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December 4, 2015

The Honorable Gina McCarthy, Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Attention: Docket ID Number EPA-OAR-2010-0505
Submitted to the Federal eRulemaking Portal (www.regulations.gov)

Re: Environmental Protection Agency's (EPA's) "Oil and Natural Gas Sector: Emission Standards for New and Modified Sources" at 80 FR 56593 (September 18, 2015)

Dear Administrator McCarthy:

American Petroleum Institute (API) respectfully submits the attached comments on the Environmental Protection Agency's (EPA's) "Oil and Natural Gas Sector: Emission Standards for New and Modified Sources" at 80 FR 56593 (September 18, 2015).

API represents over 625 oil and natural gas companies, leaders of a technology-driven industry that supplies most of America's energy, supports more than 9.8 million jobs and 8 percent of the U.S. economy, and, since 2000, has invested nearly $2 trillion in U.S. capital projects to advance all forms of energy, including alternatives. Collectively, they provide most of the nation's energy and many will be directly impacted by the proposed regulations.

The proposed rule is part of the President's "Methane Strategy," which includes multiple regulations and programs from several different agencies, intended to further reduce greenhouse gas emissions from oil and natural gas operations. However, it's important to take into account the recent methane emission trends associated with our industry. Even as U.S. oil and natural gas production has surged, methane emissions have declined significantly. For example, EPA's GHG inventory shows methane emissions from hydraulically-fractured natural gas wells have fallen nearly 79 percent since 2005 and total methane emissions from natural gas systems are down 11 percent over the same period. According to the Energy Information Agency, these reductions have occurred during a time when total U.S. gas production has increased 44% and, as a result of the increased use of natural gas, CO2 emissions from the energy sector are now near 20-year lows. These trends are indicative of what our industry, when given the freedom to innovate, can achieve to improve the environment as we bolster our nation's energy security.

Each of the proposals (Control Techniques Guidelines, Source Determination, Minor Source Tribal NSR), including this one, has potentially significant impacts on our industry's operations and, collectively, they have the potential to hinder our ability to continue providing the energy our nation demands. These cumulative impacts must be considered in conjunction with the impacts of the lowered ozone standards and the pending Bureau of Land Management (BLM) methane rule, which has not yet been proposed and will likely require costly methane controls for some of the very same emission sources. Our organizations have collaborated well in the past and API remains committed to working with EPA and the Administration to identify emission control opportunities that are both cost-effective and, when implemented, don't impact safety or hinder our ability to provide the energy our nation will continue to demand for many years to come. Attached are our comments on the "Oil and Natural Gas Sector: Emission Standards for New and Modified Sources" as well as an executive summary.

As we noted in our comment extension request, we again request that EPA officially re-open the docket for all three rulemakings when the proposed BLM methane rule is published in the Federal Register, to allow additional time for public comment once its interrelationship with the EPA proposed regulations can be fully analyzed. Also, given the limited comment period and minimal extension for these complex proposals, API will continue its review and, if warranted, provide supplemental comments to the agency that we request be included in the appropriate docket to protect the record and considered before finalizing the rules.

We look forward to working with you and your staff as these rules are developed. If you have any questions regarding the content of these comments, please contact Matthew Todd (toddm@api.org, 202-682-8319).

Sincerely,

Howard J. Feldman

Howard J. Feldman

Cc: Janet McCabe, EPA
Joe Goffman, EPA
Peter Tsirigotis, EPA
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Attachment

API Comments on the Proposed Rulemaking – Standards of Performance for New Stationary Sources: Oil and Natural Gas Production and Natural Gas Transmission and Distribution

December 4, 2015

Docket ID No. EPA-HQ-OAR-2010-0505

EXECUTIVE SUMMARY

As detailed in our comments, API has numerous concerns with EPA's proposed New Source Performance Standard (NSPS) rulemaking for the oil and natural gas sector (40 CFR Part 60, Subpart OOOOa). EPA has indicated the desire to finalize the proposed rule in June of 2016. We are concerned that this artificial deadline will hinder the agency's ability to adequately address stakeholder comments and develop a final rule that protects the environment and does not hinder America's energy renaissance. This is an unrealistic schedule for issuing a complex rule with the concerns identified that cover oil and natural gas industry segments as large and diverse as the onshore production, processing, and transmission and storage segments. EPA has only a few months to review and analyze all the submitted comments, make appropriate revisions, and complete the necessary internal and interagency reviews. As such, EPA should take sufficient time between the close of the comment period and promulgation of the final rule to adequately consider and address public comments.

Many of API's concerns stem from the broad applicability of the proposed rule and the one-size-fits-all approach to regulating an industry that varies greatly in the type, size and complexity of operations. EPA has justified the proposed regulation using economic studies on "average model facilities" without determining whether the resulting proposed control requirements are appropriate for the entire range of sources included in the source category. The proposed rule applies NSPS in unique and unprecedented ways to categories and equipment not previously listed, while relying on unsound legal justification. The notification, monitoring, recordkeeping, performance testing and reporting requirements are significantly more burdensome than justified for the small and/or temporarily affected facilities.

Listed below are API's primary concerns with the proposed rule. To facilitate review of our comments, API has summarized the concern and provided a recommendation with a reference to the detailed comments where additional supporting discussion has been included.

Direct Regulation of Methane is Unlawful

Issue – Section 111 of the Clean Air Act (CAA) requires the Agency to list a category of stationary sources if, in the Administrator's judgment, the category "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." CAA §111(b)(1)(A). It is unlawful for EPA to regulate only methane from oil and natural gas sources based on an endangerment finding that is largely attributable to other GHG pollutants from non-stationary sources. In the 2009 endangerment finding for motor vehicles, EPA found that "carbon dioxide is expected to remain the dominant anthropogenic greenhouse gas, and thus driver of climate change." See, e.g., 74 Fed. Reg. at 66519. Given that EPA concluded that carbon dioxide from motor vehicles—not methane— is the "driver of climate change," EPA cannot rely on that past finding in a rule that regulates only methane. EPA has not shown that there is a rational basis for concluding that methane, a single element of the aggregate pollutant GHGs, meets the endangerment standard called for in the CAA, or that upstream oil and natural gas sources are a significant contributor of methane. Both showings are legal prerequisites before EPA may propose Subpart OOOOa.

Recommendation – EPA must make both an endangerment and significant contribution finding for each pollutant that it seeks to regulate for a given source category. In this case, an endangerment finding must be made for methane specifically, and a significant contribution finding must be made for the proposed covered sources.

Refer to Comments 3.0 and 4.0 for detailed comments on this matter.

Direct Regulation of Methane is Unnecessary

Issue – In the proposed rule, EPA states that, for some of the regulated affected facilities, direct regulation of methane accomplishes no further reduction in methane emissions than would occur through regulation of VOC alone. EPA recognizes that under its proposal, the same controls would be required for VOC and methane as are currently required for VOC under Subpart OOOO. EPA's decision to directly regulate methane from those same sources covered by OOOO, despite this admission - which means that no significant additional methane emissions reductions will occur - is arbitrary and capricious. There is no rational basis for taking the wholly discretionary action of regulating methane or GHGs from this part of the oil and natural gas sector where EPA would achieve no additional methane reductions beyond those achieved through existing VOC standards. None of EPA's asserted reasons have merit, and therefore, EPA has not made a showing that revision of the standards is "appropriate," as required under section 111(b)(1)(B).

Recommendation – EPA should continue the practice of indirectly regulating methane through the use of natural gas as a surrogate for VOC.

Refer to Comment 7.0 for detailed comments on this matter.

EPA Needs to Address Permitting Implications Associated with Regulation of Methane

Issue – EPA has not addressed the possible permitting implications that would flow from of the direct regulation of methane. Unintended implications could include allowing methane alone to trigger PSD and Title V permitting for all sources, not just oil and natural gas sources, which would greatly increase permitting burdens and result in costs that EPA did not consider in the rulemaking. API has raised PSD permitting issues previously with the EPA and understands that EPA does not intend for NSPS OOOOa to trigger PSD and Title V permitting applicability as that runs counter to both Congressional intent and judicial precedent. Agencies and states cannot handle an increased permitting burden, and such a trigger would drastically increase the number of permits submitted, not only for the oil and natural gas sector, but for all sectors.

Recommendation – As a threshold matter, API presents the following solution to the PSD and Title V permitting issues without conceding its position that EPA is required to make a separate endangerment finding for methane and a significant contribution finding for methane from this source category. To address the possible PSD and Title V permitting implications, EPA should adopt an approach similar to that taken in the Clean Power Plan (NSPS Subpart TTTT). Specifically, EPA should make it clear that the pollutant being regulated under NSPS OOOOa is the group of six GHGs. EPA should also make it explicitly clear that methane is being used as a surrogate for the group of six. Additionally, EPA should include an explanation as well as a provision in the final rule that extends the Tailoring Rule to cover regulation of GHGs under NSPS OOOOa.

Refer to Comment 6.0 for detailed comments on this matter.

Equipment Leak Requirements

Issue – EPA has proposed a process that requires significant, unnecessary recordkeeping and reporting and requires surveys of sites that are proven to have little to no detectable leaks. Associated proposed definitions unnecessarily complicate compliance. Additionally, the initial semi-annual frequency is not warranted, and the complex process for determining frequency introduces a burdensome paperwork exercise with no emissions reduction benefit. Closed vent systems (CVS) should not be subject to duplicative requirements. As well, leak detection should not be duplicative with other state or federal enforceable leak detection requirements.

Recommendation –Streamline program to require annual inspections at sites with a compressor or storage vessel. Eliminate the requirement for a site-specific monitoring plan. Existing programs demonstrate that monitoring with an annual frequency results in very low emissions. A companywide monitoring plan will cover all the relevant material; there is no added benefit and significant added cost of developing thousands of site-specific monitoring plans. Revise definitions according to our recommendations. CVS monitoring requirements should be the same as those for fugitive emission components. Finally, exempt sites subject to state, local, or other federally enforceable leak detection programs.

Refer to Comment 27.0 for detailed comments on this matter.

Pneumatic Pump Applicability and Technical Feasibility

Issue – EPA is proposing to regulate low emitting sources which would add considerable expense and burden while providing very limited environmental benefit. EPA has ignored critical technical and safety issues in assuming that pneumatic pumps can be readily connected to existing closed vent systems. There are numerous potential safety and operational issues with connecting the discharge from a pneumatic pump to an existing control device and closed vent system. These issues can impact both the performance of the pump and result in back pressure on the other sources being controlled.

Recommendation – EPA should exempt low emitting pumps and low usage pumps, i.e. pumps that emit at an equivalent rate lower than a high bleed controller. This would be consistent with the position taken in Subpart OOOO and reinforced under the Subpart OOOOa proposal for pneumatic controllers. EPA should also provide an exemption from the requirements to control pump emissions where it has been determined to be technically infeasible or potentially unsafe.

Refer to Comment 24.0 for detailed comments on this matter.

Oil Well Completions

Issue – EPA needs to accommodate additional exemptions for certain oil well completions. There are a wide range of conditions experienced across different oil and natural gas fields and additional provisions are needed in the rule to clearly exempt certain scenarios.

Recommendation – In addition to the exemption for wells producing less than 300 scf of gas per bbl of oil, EPA should include exemptions for wells requiring artificial lift to complete flowback and for periods when flowback has stable entrained gas, foam, emulsion, or infrequent slugging gas flow such that a separator cannot be operated.

Refer to Comment 22.2 for detailed comments on this matter.

EPA Must Recognize Implementation Challenges

Issue – As we learned in the development of Subpart OOOO, API urges EPA to exercise caution in the development of these rules to allow operational flexibility as it seeks "one size fits all" regulatory solutions. Consideration must be given to the implementation of these new rules to ensure industry is able to comply. Consistent with the original Subpart OOOO rulemaking, EPA should consider a similar compliance schedule for the proposed NSPS rule. We would also urge EPA to accommodate operators that are currently implementing leak monitoring and repair requirements, whether due to existing air permits, state or local regulations or voluntary commitments, to satisfy the federal rule requirements and minimize regulatory burden for those operators.

Recommendation – If promulgated as written, EPA should allow a phased implementation for completion, pneumatic pump, and leak detection and repair (LDAR) requirements to accommodate the number of affected facilities and the associated engineering, implementation and training needed to comply with the new rules.

Refer to Comments 22.5, 24.0 and 25.0 for detailed comments on this matter.

Compliance Assurance Requirements for Subpart OOOOa Are Overly Burdensome

Issue – The monitoring and testing requirements are overly burdensome for Subpart OOOOa. The remote, dispersed and unmanned nature of facilities that lack electrical power, make the requirements logistically impractical, technically difficult and uneconomic. The use of NESHAP HH major source-type compliance requirements for storage vessels is confusing and unjustifiably stringent for NSPS.

Recommendation – CPMS requirements for monitoring centrifugal compressors and pneumatic controllers should be eliminated in lieu of the sensory inspections required for storage vessels. Additionally, the performance testing requirements should be revised.

Refer to Comment 12.2 and 12.4 for detailed comments on this matter.

Subpart OOOO Retroactive Requirements

Issue- EPA proposed several new requirements for control devices and closed vent systems to subpart OOOO that could be viewed as new requirements to be applied retroactively to affected facilities initially constructed between August 23, 2011 and September 18, 2015. This is inappropriate as NSPS rule changes may only be prospective and not retrospective. Amongst the numerous changes, proposed paragraph §60.5370(d) encapsulates the problem best by stating: *You are deemed to be in compliance with this subpart if you are in compliance with all applicable provisions of subpart OOOOa of this part.* This suggests that new requirements in subpart OOOOa for subpart OOOO affected facilities will be applicable when subpart OOOOa is finalized. The only purpose for modifying subpart OOOO should be to end date the rule since it is being replaced with subpart OOOOa.

Recommendation – EPA should remove all new compliance requirements being proposed in subpart OOOO and only finalize changes to paragraphs §60.5360 and §60.5365 which end date the applicability of subpart OOOO and that correct issues that do not add new regulatory burden.

Refer to Comment 19.0 for detailed comments on this matter.

Multipollutant Cost Effectiveness Approach is Not Appropriate

Issue – In justifying the proposed requirements, EPA utilized a multipollutant approach to determine if costs were reasonable. EPA's reliance on the multipollutant methodology is arbitrary and capricious because it is inconsistent with EPA's own "rational basis" test for determining whether regulation of an additional pollutant from a source category is appropriate. As EPA clearly states, under its "rational basis" test, the Agency must have a rational basis for regulating *each* "pollutant." *See* 80 Fed. Reg. at 56601. EPA's multipollutant approach is inconsistent with that test because it allows the Agency to find that regulation of multiple "pollutants" is reasonable where regulation of each pollutant individually would not be. *See id.* at 56636.

Recommendation – EPA must re-evaluate and only assess the reasonableness of costs based on each pollutant.

Refer to Comment 10.0 for detailed comments on this matter.

Social Cost of Methane

Issue – EPA has inappropriately applied a social cost of methane (SC-CH_4) estimate that is highly speculative, not sufficiently peer-reviewed, and ultimately not suitable for policy applications. The SC-CH_4 is based on the approach used for quantifying the social cost of carbon (SCC) and therefore carries with it all of the same challenges to accurately calculating the benefits of the rule, and seriously affect the scientific and economic reliability of the SC-CH_4. The peer-reviewers selected by EPA did not reach a consensus and all found inconsistencies and other issues with the calculations used to generate the SC-CH_4, as did an independent review by NERA. The issues associated with the estimation and use of the SC-CH_4 include: differences in the way methane emissions was included in the three models; significant differences in the damage functions between the models; issues with the averaging approach used to synthesize the results; the inclusion of an unjustifiably low discount rate given the short atmospheric lifespan of CH_4; the inclusion of global benefits rather than domestic benefits; and the *ad hoc* nature of EPA's assumption of the indirect effects on radiative forcing. Independent review by NERA found that the benefits provided by the rule, after compensating for flaws in EPA's calculation, could be as much as 94% lower. When combined with the revised cost estimates and reduced emission benefits found by ERM, the rule could result in net costs of more than $1 billion in 2025.

Recommendation – There are significant uncertainties inherent in the newly-developed social cost of methane (SCM) calculation, and it may significantly overestimate methane's environmental impacts. Further, there has been a lack of adequate peer review for the SC-CH_4 estimate. As such, EPA's use of the social cost of methane is inappropriate to justify this rulemaking.

Refer to Comment 21.0 for detailed comments on this matter.

Next Generation Compliance

Issue – API believes the Next Generation Compliance Options discussed in the proposal preamble are unnecessary and represent an overreach by EPA of its authority. API believes the Next Generation Compliance Alternatives discussed in the preamble are not feasible or legal, nor do they achieve goals of assuring better compliance.

Recommendation – EPA must justify the legal basis for and formally propose any Next Generation Compliance provisions in a separate rulemaking before adopting them.

Refer to Comment 18.0 for detailed comments on this matter.

Electronic Reporting

Issue – EPA should not write electronic reporting into Subpart OOOO and Subpart OOOOa until the system is able to accommodate the unique nature of the oil and natural gas industry. The electronic reporting system is not proven generally at this time. Further, the system will require configuration to allow the current area based reporting vs facility by facility. In the past, system revisions have resulted in significant IT challenges, and appropriate time needs to be allowed for the agency to develop, QA/QC, user test and train reporters on the new system.

Recommendation – EPA should amend the final rule language to formally allow for continuation of current reporting approaches (under Subpart OOOO) for three years to allow for rollout of the electronic reporting system..

Refer to Comment 11.0 for detailed comments on this matter.

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Attachment A – Recommended Rule Language Edits

Attachment B – API Comments on EPA's NSPS Electronic Reporting Proposal

Attachment C – Technical Review of Western Climate Initiative Proposals to Meter Fuel and Control Gas

Attachment D – API Comments on EPA's White Paper on Liquids Unloading

Attachment E – API's Review of EPA's Cost Benefit Analysis

Attachment F – Comparison of the LDAR Requirements Proposed in Subpart OOOOa to Existing State LDAR Program

GENERAL COMMENTS

Throughout these comments API has provided suggested rule language to assist in revised regulatory text in redline/strikeout format. A consolidated version is provided of recommended rule language in Attachment A by section. While Attachment A has been prepared as a summary of API's suggested edits to the rule language, the markups shown in these comments should be taken as our preferred position in the event of any differences between these comments and Attachment A.

1.0 EXTENSION OF COMMENT PERIOD AND FINAL RULE DEADLINE

While API appreciates the additional 17 day extension that EPA granted to submit comments, a minimum of 120 days was required to provide an adequate set of comments to a rulemaking as broad, high impact, precedent setting, and complex as these proposed rules. Further, the NSPS rules are only a part of the proposed regulations that our industry is facing. EPA has also released proposed control technique guidelines for implementation of the revised ozone air quality standard and pending regulatory requirements from the Department of Interior's BLM on federal lands will also add to the cumulative impact to our industry and future operations. We urged the EPA and the Administration to coordinate its efforts and strongly encouraged EPA to extend its comment periods to allow a minimum of 30 days overlap with the BLM rulemaking currently under development.

Without this overlap, industry does not have the chance to understand the cumulative impacts and provide meaningful feedback to avoid conflicting requirements across the separate agencies. API has developed as complete a set of comments as time allowed. However, much of the information EPA requested, as well as additional information API wanted to provide is not included because of time limitations.

2.0 EPA UNLAWFULLY SEEKS TO EXPAND THE OIL AND NATURAL GAS SECTOR SOURCE CATEGORY

In the proposed rule, EPA seeks to unlawfully expand the scope of the oil and natural gas sector source category—even beyond the expansion that EPA undertook in 2012 with Subpart OOOO, which API has opposed as unlawful.[1] EPA's attempt here to expand even further the types of emissions sources that would be subject to the NSPS is likewise unlawful. In this proposal, several types of never-before-regulated emissions sources would be regulated under NSPS: hydraulically fractured oil well completions, pneumatic pumps and fugitive emissions from well sites, and compressor stations. 80 Fed. Reg. at 56594. Some source types would also be regulated more generally for methane and VOC emissions, as only a small subset are currently regulated for VOC: pneumatic controllers, centrifugal compressors, and reciprocating compressors (except for compressors at well sites). *Id.* at 56595.

2.1 The Scope Of The Source Category Is Unlawfully Overbroad And Not Supported By The 1979 Listing Or The Gas Processing Plant NSPS

EPA's proposed NSPS would cover an even greater number of very small source types in EPA's broadly defined "oil and natural gas source category," which, according to EPA, includes production, processing,

[1] API Comments on 2011 Proposed NSPS at 3-8 (Nov. 30, 2011), EPA-HQ-OAR-2010-0505-4266 ("API 2011 Comments").

transmission, and storage. Id. at 56594. EPA again maintains, as it did in the original Subpart OOOO rulemaking, that all emissions sources proposed for regulation are covered by its 1979 listing of the oil and natural gas category. See id. at 56600 ("EPA interprets the 1979 listing broadly to include the various segments of the natural gas industry (production, processing, transmission, and storage).").

EPA is incorrect that the 1979 original source category determination can be read to include the numerous smaller emissions points covered by this proposal. The 1979 listing was focused on major-emitting operations and cannot be reasonably construed as encompassing small, discrete sources that exist separate and apart from a large facility, like a processing plant.

In its 1979 listing, EPA made it clear that the category was listed to satisfy section 111(f) of the Clean Air Act. 44 Fed. Reg. 49222 (Aug. 21, 1979). That section required EPA to create a list of "categories of major stationary sources" that had not been listed as of August 7, 1977, under section 111(b)(1)(A) of the Act and to promulgate NSPS for the listed categories according to a set schedule. EPA explained in the listing rule that its list included "major source categories," which EPA defined to include "those categories for which an average size plant has the potential to emit 100 tons or more per year of any one pollutant." Id.

Although EPA provided no further explanation in its original 1979 listing decision as to what facilities it intended to regulate under the "crude oil and natural gas production" source category, there can be no doubt that the category originally included "stationary sources" (i.e., "plants") that typically have a potential to emit at least 100 tons per year of a regulated pollutant. This communicates two important limitations on the original listing decision. First, EPA was focused on discrete "plants" or "stationary sources." Second, EPA was focused on large emitting plants or stationary sources. As a result, the original listing decision cannot reasonably be interpreted to extend to the types of sources EPA seeks to regulate in the proposal. The additional source types that EPA seeks to regulate in this proposal could not plausibly be considered part and parcel of major emitting plants.

EPA claims that its priority list analysis at the time of original listing shows that the Agency intended to regulate sources beyond the "production source segment" category because EPA evaluated equipment that is used in various segments of the natural gas industry, such as stationary pipeline compressor engines. 80 Fed. Reg. at 56600. But this does not evince an intent to regulate non-major source types but only that the Agency evaluated equipment located at what it perceived to be major facilities.

EPA next asserts that in the preamble to a subsequently proposed NSPS for natural gas processing plants, "EPA described the major emission points of this source category to include process, storage and equipment leaks," and that this supports broad regulation of even the smallest sources in the oil and natural gas industry. See id. (citing 49 Fed. Reg. 2636, 2637 (Jan. 20, 1984)). But, EPA recognized that the emissions points it was proposing to regulate in that rulemaking—process units and compressors—were located at gas processing plants. 49 Fed. Reg. at 2638; see also 50 Fed. Reg. 26122, 26123 (June 24, 1985) (affected units in final rule are process units and compressors at gas processing plants). It is telling that the Agency decided to regulate only natural gas processing plants—the closest thing to a major-emitting plant that can be found in this sector—in that NSPS.

2.2 EPA Is Not Authorized To Arbitrarily Expand A Source Category

As explained above, EPA incorrectly asserts that it is not listing a new source category or otherwise expanding the existing category. See 80 Fed. Reg. at 56600-01. The Agency goes on to say that even if a revision of the source category were required, it believes it is presenting information sufficient to support that revision by showing that four "segments" of the oil and natural gas industry warrant regulation. Id. at 56601, 56608-09. EPA is incorrect.

EPA fails to make the required statutory findings. Under section 111(b)(1)(A), EPA is authorized to regulate additional source types if and only if it: (1) defines a discrete "category" of stationary sources;

and (2) determines that emissions from the source category cause or significantly contribute to endangerment to health or the environment.

EPA makes no effort whatsoever to demonstrate that emissions from the particular additionally-regulated sources in Subpart OOOOa cause or contribute to endangerment to health or the environment. Instead, the Agency simply asserts general public health effects associated with GHGs, VOC, and SO_2 and then evaluates emissions from oil and natural gas sources generally. See id. at 56601-08. For methane, EPA merely breaks down emissions into four general "segments" (natural gas production, natural gas processing, natural gas transmission and storage, and petroleum production) but does not evaluate particular source type emissions within those segments. EPA does nothing to break down its evaluation of emissions even by sector segment for SO_2 and VOC. This failure to investigate the key statutory listing criteria is patently arbitrary and plainly violates the requirement in section 307(d)(3) of the Clean Air Act to clearly set forth the basis and purpose of the proposal.

Under EPA's logic, as long as certain types of stationary sources in a category, or segment of a category, cause or significantly contribute to endangerment to health or the environment, it can lump together in the defined source category (or segment of a source category) all manner of ancillary equipment and operations, even if those ancillary equipment and operations do not in and of themselves significantly contribute to the previously-identified endangerment. See id. at 56601. This is not a reasonable interpretation of section 111(b)(1)(A) because such an interpretation would bestow virtually unlimited regulatory authority upon EPA—allowing EPA to evade the express listing criteria by creating loose associations of nominally related sources in a sector.

Lastly, section 111(f)(3) of the Clean Air Act requires EPA to "consult with appropriate representatives of the Governors" prior to "promulgating any regulations under this subsection." As explained above, EPA originally listed the "crude oil and natural gas production" source category in 1979 pursuant to section 111(f), which means that the requirement of section 111(f)(3) applies. Consequently, EPA has a clear obligation to consult with the Governors and should have done so prior to proposing the rule so that the public would have an opportunity to know the views of the Governors and submit comments on the record. Although EPA did have some general discussions with the States, see id. at 56609, this does not meet the procedural requirement of section 111(f)(3). EPA's failure to consult with the Governors and State air pollution control agencies on the specific substance of this proposal—including whether the category can be revised in the way contemplated and whether the standards are appropriate – is a fundamental procedural error. The uniqueness of the new affected facilities (very small in cost and/or quantity of emissions or of non-routine, temporary, and construction nature) in particular justifies consultation with the States on the specific proposed action as it will further increase the States' permitting burdens if finalized.

2.3 EPA's Regulation Of Extremely Small Affected Facilities Is Unlawful

As it did in the 2012 rule finalizing Subpart OOOO, EPA errs in this proposal in asserting that single individual components (such as pneumatic devices, compressors, and tanks) and single activities (such as each oil well completion) constitute separate "affected facilities" for purposes of the NSPS. *See e.g.*, Proposed § 60.5365a, 80 Fed. Reg. at 56663. EPA's fine parsing of the definition of affected facility to expand applicability of the rules is fundamentally flawed for three distinct reasons.

First, EPA fails to explain where it finds legal authority for such an approach, and thus, falls far short of EPA's obligation to include in the proposed rule "the major legal interpretations… underlying the proposed rule." CAA § 307(d)(3)(C).

Second, and more importantly, the proposal is flawed because the statute simply does not confer authority on EPA to define a source category and then define a different "affected facility" for purposes of determining what constitutes a new source. As explained above, the statute unambiguously requires EPA to identify and regulate "categories of stationary sources." *Id.* § 111(b)(1)(A). Similarly, the statute defines the term "new source" to mean "any stationary source" that is constructed or modified after proposal of an applicable standard. *Id.* § 111(a)(2). There can be no doubt that the "stationary source" that is identified for listing purposes must be the same "stationary source" used to define what constitutes a new source. In other words, by defining a category of "stationary sources" to be regulated under section 111, EPA unavoidably identifies the "stationary source" that must be used in applying the definition of "new source." *See* 80 Fed. Reg. at 56610 ("We note that the terms 'emission source,' 'source type' and 'source,' as used in this preamble, refer to equipment, processes and activities that emit VOC and/or methane. This term does not refer to specific facilities, in contrast to usage of the term 'source' in the contexts of permitting and section 112 actions.").

To be sure, section 111 provides EPA with some regulatory flexibility—for example, the Agency clearly "may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards." CAA § 111(b)(2). But the authority to parse a given category of stationary sources for purposes of standard setting is distinctly different from the asserted authority to redefine what constitutes a "new source" within the given source category. *Asarco Inc. v. EPA*, 578 F.2d 319, 327 n.24 (D.C. Cir. 1978) ("This language on its face merely allows the Administrator to set different standards for different classes, types, and sizes of sources. It does not give the Administrator authority to rewrite the definition of a stationary source…."). EPA has flexibility in defining in the first instance the stationary sources to be regulated, but the act of defining the "stationary sources" fixes the "affected facility" for purposes of determining what constitutes a new source.

Third, even assuming for the sake of argument that EPA has authority to designate portions of stationary sources as "affected facilities" for purposes of determining what constitutes a "new source," EPA has failed to follow the analytical framework established in prior rules for making such designations. For example, in establishing the NSPS for VOC emissions from synthetic organic chemical manufacturing industry ("SOCMI") wastewater, EPA explained that a balancing must be done. A "narrower" definition of affected facility can be favorable because "a broader definition means that replacement equipment is less likely to be regulated under the NSPS." 59 Fed. Reg. 46780, 46789 (Sept. 12, 1994). On the other hand, a "broader" definition may be appropriate upon consideration of "the relevant statutory factors (technical feasibility, cost, energy, and other environmental factors)." *Id.* In the case of the SOCMI rule, EPA selected the process unit as the appropriate affected facility because it "allows for routine equipment replacement and minor changes or expansions in existing facilities without subjecting either single emission sources or entire plant sites to requirements of the proposed standards." *Id.* at 46790. EPA's failure to engage in reasoned assessment according to these established criteria renders the proposed rule arbitrary and capricious and not in accord with the law.

2.4 Hydraulically Fractured Oil Well Completions Cannot Be "Affected Facilities" Under NSPS

In this rulemaking, EPA proposes to regulate hydraulically fractured oil well completions for the first time. API has opposed EPA's prior proposal to regulate natural gas well completions. *See* API 2011 Comments at 7-8. EPA rejected those comments in a cursory manner in the 2012 Subpart OOOO final rule. 77 Fed. Reg. at 49511 n.11. EPA disagreed with API's assertion that EPA's regulation of well completion is a regulation of "construction activities," and instead maintained that the Agency was regulating "emissions resulting from the physical change." *Id.*

API reiterates its comments made with regard to natural gas well completions because they are equally applicable to EPA's proposal to regulate oil well completion for the first time. Emissions from well completions differ fundamentally from emissions regulated under any NSPS prior to Subpart OOOO. It goes without saying that the purpose of oil wells is to produce oil. A well completion is not part of the normal operation of a well in that completion activities do not continuously occur as a well is producing or, for that matter, are not repeated more than once or twice over the life of a well (a life that typically spans years and often spans decades). Instead, a well completion is a construction-related activity that must be accomplished for a well to begin producing and thereafter engage in normal operations. To the extent that a producing well must be "recompleted," this activity constitutes maintenance of the well because it is needed to assure the ongoing proper operation and suitable productivity of the well.

Until EPA's unlawful regulation of natural gas wells in 2012, EPA had never sought to impose section 111 emissions limitations or standards on construction or maintenance activities at affected facilities. In fact, EPA had actively worked to exclude construction and maintenance activities from coverage by an NSPS. For example, the initial performance tests and compliance determinations for affected facilities typically are not required to be conducted until "within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility." 40 C.F.R. § 60.8(a). Similarly, performance tests must be conducted under conditions reflecting "representative performance of the affected facility." *Id.* § 60.8(c). Prior to Subpart OOOO, periods of source construction and maintenance had never been suggested to be "representative" of normal source operation under the NSPS program.

To the extent that well completions can be considered a "stationary source," which API disputes , they are a distinct type of stationary source that cannot rationally belong to the same source category as the other disparate elements of the oil and natural gas production industry (such as natural gas processing plants). EPA has not previously found and has not proposed to find that emissions from well completions cause or significantly contribute to air pollution that may reasonably endanger health or the environment. Therefore, EPA is not authorized to list or regulate well completions under section 111.

In addition, EPA has not explained why it has not followed a decades-long practice under section 111 of regulating emissions that result only from normal operation of affected facilities and expressly excluding construction-related emissions from regulation in this proposal. As noted in API's 2011 comments, regulation of construction-related emissions is a significant substantive departure in the Agency's prior interpretation and implementation of section 111. The failure to provide a reasoned explanation of why this departure is justified, and the failure to present the legal basis for regulating non-routine emissions, is arbitrary and capricious and plainly violates EPA's obligation to clearly set forth "the major legal interpretations and policy considerations underlying the proposed rule." CAA § 307(d)(3)(C).

3.0 EPA CANNOT RELY ON AN ENDANGERMENT FINDING FOR A COLLECTION OF SIX GREENHOUSE GASES TO REGULATE ONLY METHANE

Section 111 requires the Agency to list a category of stationary sources if, in the Administrator's judgment, the category "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." *Id.* § 111(b)(1)(A). This requires the Agency, first, to make an "endangerment finding" that the air pollution it intends to regulate from that source category "may reasonably be anticipated to endanger public health or welfare." *Id.* Next, the agency must determine that the source category "causes, or contributes significantly to" that air pollution. *Id.* These threshold findings are required before EPA proposes new standards for existing source categories.

In December 2009, EPA made an endangerment finding for motor vehicles under section 202(a) of the Clean Air Act in which the Agency determined that "six greenhouse gases *taken in combination* endanger both the public health and the public welfare . . . ." 74 Fed. Reg. 66496, 66497 (Dec. 15, 2009) (emphasis added). EPA "[s]pecifically . . . define[d] the 'air pollution' referred to in CAA section 202(a) to be the *mix of six long-lived and directly-emitted greenhouse gases* . . .," *id.* at 66497 (emphasis added), in the "aggregate," *id.* at 66519. EPA made clear that "the air pollution is the *combined mix* of six key directly-emitted, long-lived and well-mixed greenhouse gases . . . ." *Id.* at 66516 (emphasis added). The six greenhouse gases included in the aggregate in EPA's section 202(a) endangerment finding were carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). *Id.*

In the proposal here, EPA "identifies the air pollutant that it proposes to regulate as the pollutant GHGs . . . ." *Id.* at 56601. EPA explains that of the "six well-mixed GHGs . . . only two of these gases—CO_2 and methane—are reported as non-zero emissions for the oil and natural gas production sources and natural gas processing and transmission sources that are being addressed within this rule." *Id.* at 56607-08. As EPA admits, however, "only methane will be reduced directly by the proposed standards." *Id.*

It is unlawful for EPA to regulate only methane based on an endangerment finding that is largely attributable to other pollutants. Of the six greenhouse gases, carbon dioxide is emitted in vastly greater quantities (even on a carbon dioxide equivalent basis) than methane. In the 2009 endangerment finding for motor vehicles, EPA recognized this, finding that "carbon dioxide is expected to remain the *dominant anthropogenic greenhouse gas, and thus driver of climate change*." *See*, *e.g.*, 74 Fed. Reg. at 66519. Given that EPA concluded that carbon dioxide—not methane— is the "driver of climate change," EPA cannot rely on that past finding in a rule that regulates only methane. EPA has not shown that there is a rational basis for concluding that methane, a single element of the aggregate pollutant GHGs, meets the endangerment standard called for in the statute.

4.0 EPA MUST MAKE AN ENDANGERMENT AND SIGNIFICANT CONTRIBUTION FINDING FOR EACH POLLUTANT THAT IT SEEKS TO REGULATE FOR A GIVEN SOURCE CATEGORY

EPA sets forth a so-called "rational basis" approach to the regulation of pollutants under section 111 under which it asserts that an endangerment and significant contribution finding based on *one* pollutant emitted by a source category broadly gives EPA the ability to regulate *any* pollutant emitted from that source category. EPA claims that:

[O]nce the EPA has determined that the source category causes, or contributes significantly to, air pollution that may reasonably be anticipated to endanger public health or welfare, and has listed the source category on that basis, the EPA interprets section 111(b)(1)(A) to provide authority to establish a standard of performance for *any* pollutant emitted by that source category as long as the EPA has a rational basis for setting a standard for the pollutant.

80 Fed. Reg. at 56601 (emphasis added). EPA bases its position on three claims. First, EPA argues that the Agency is not required to make a new endangerment finding with regard to the source category because it is not listing a new source category. *Id.* In EPA's view, section 111(b)(1)(A) requires an endangerment finding only in order to initially list a source category. *Id.* Second, EPA argues that EPA has discretion, in what it determines to be a statutory gap, to specify what pollutants should be regulated once a source category is listed. *Id.* Third, EPA claims that past Agency practice supports this approach. *See id.* ("EPA has previously interpreted this provision as granting it the discretion to determine which pollutants should be regulated."). As such, EPA "believes that the 1979 listing of this source category provides sufficient authority for this action . . . ." *Id.*

EPA's interpretation directly contradicts the plain language of section 111(b)(1)(A) of the Clean Air Act. That section requires EPA to list a category of stationary sources if, in the Administrator's judgment, the category "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." CAA § 111(b)(1)(A). This section unambiguously requires EPA to list and regulate according to endangerment and significant contribution findings for particular pollutants. EPA mistakes its source of authority for an unlimited grant of authority. Read in context, the statute permits EPA to regulate stationary sources that emit pollutants that may reasonably be anticipated to endanger public health or welfare *for those pollutants* which led to the endangerment finding and to which the source category significantly contributes. It does not grant EPA unlimited authority to regulate *any* pollutant emitted by that source. *See Mich. v. EPA*, 268 F.3d 1075, 1081 (D.C. Cir. 2001) ("EPA is a federal agency—a creature of statute. It has . . . only those authorities conferred upon it by Congress . . . . [I]f there is no statute conferring authority, a federal agency has none.").

Even if the statute were ambiguous, EPA's interpretation of the statute is unreasonable. EPA claims that the statute is silent as to what pollutants should be the subject of standards from the source category, and "in the absence of specific direction or enumerated criteria in the statute concerning what pollutants from a given source category should be the subject of [a] standard, it is appropriate for EPA to exercise its authority to adopt a reasonable interpretation of this provision." 80 Fed. Reg. at 56593, 56601. Into this alleged statutory silence, EPA injects the "authority to establish a standard for performance for *any pollutant* emitted by that source category as long as the EPA has a rational basis for setting a standard for the pollutant." *See id.* (emphasis added). Regulating any pollutant emitted from a source category based on an endangerment and significant contribution finding for just a single pollutant is manifestly unreasonable. EPA may not simply substitute a "rational basis test," which is not contained in Section 111 of the Clean Air Act, for its more stringent requirements.

Under the Agency's interpretation, EPA's regulation of *any* pollutant is limited only by EPA's prior determination that *an entirely different pollutant* endangers public health or welfare, that the source category's emissions of that different pollutant contribute significantly to that endangerment, and that there is somehow a "rational basis"—words not found in section 111— to regulate other pollutants. This is not a test. It is an unlimited grant of authority for EPA to be the final arbiter of whether to regulate pollutants for which it has not made the necessary statutory findings.

After a single endangerment and contribution finding, EPA could for all intents and purposes regulate any pollutant from that source regardless of whether the source contributed significantly to the endangerment in question. This is not what Congress intended when it established such a high bar for regulation under section 111(b). *See* CAA § 111(b)(1)(A). EPA's interpretation is untethered from the statute, adrift in an unlimited "rational basis test" of the Agency's own creation. This is a patently unreasonable interpretation of the statute.

EPA's position is even more untenable because it relies on a cause-or-contribute significantly finding made for a different pollutant over thirty years ago. A significant period of time has passed since EPA made its finding. EPA's original finding for this source category may no longer be valid. Regulating methane on the basis of a finding made many years earlier that the source category contributed significantly to endangering pollution of another kind without an independent examination and analysis of the pollutant that EPA intends to regulate is arbitrary and capricious.

5.0 THE PROPOSED SIGNIFICANT CONTRIBUTION FINDING FOR METHANE EMISSIONS FROM THE OIL AND NATURAL GAS SECTOR IS UNLAWFUL BECAUSE EPA FAILED TO DEFINE WHAT CONSTITUTES "SIGNIFICANT" CONTRIBUTION

As an alternative to its "rational basis" test, EPA proposes to find that methane emissions from the oil and natural gas sector contribute significantly to endangering GHG emissions. 80 Fed. Reg. 56593, 56601. This alternative finding is unlawful because EPA provides no legal basis or analysis as to what constitutes a "significant contribution." In fact, EPA's recent actions suggest that EPA has no standard for making a "significant contribution" finding. When EPA proposed standards of performance for GHG emissions from new electric generating units ("EGUs"), the Agency stated in the preamble that:

[I]f the EPA were required to make a cause-or-contribute-significantly finding for CO_2 emissions from the fossil fuel-fired EGUs, as a prerequisite to regulating such emissions under CAA section 111, the same facts that support our rational basis determination would support such a finding. In particular, as noted, *fossil fuel-fired EGUs emit almost one-third of all U.S. GHG emissions*, and constitute by far the largest single stationary source category of GHG emissions; and the CO_2 emissions from even a single new coal-fired power plant may amount to millions of tons each year.

79 Fed. Reg. 1430, 1456 (Jan. 8, 2014). EPA noted that "at present, it is not necessary for the EPA to decide whether it must identify a specific threshold for the amount of emissions from a source category that constitutes a significant contribution" because "[u]nder any reasonable threshold or definition, the emissions from EGUs are a significant contribution." *Id.* Thus, in the proposed NSPS for EGUs, EPA recognized that a specific reasonable threshold for "significant contribution" may be necessary, but the agency determined that one-third of all U.S. GHG emissions would be significant "[u]nder any reasonable threshold." *Id.*

Regardless of EPA's position in the proposed NSPS for EGUs, it is plainly unreasonable fro EPA to make the same assumption here. In the proposed rule, EPA concludes that GHG emissions from oil and natural gas processing and transmission sources constitute 3 percent of total GHG emissions in the United States and 0.3 percent of global GHG emissions. 80 Fed. Reg. 56593, 56608. Yet, EPA does not provide any analysis for why three percent of emissions may be significant, identify at what level GHG emissions are significant, or explain why it believes it is unnecessary for it to identify a threshold for significance. The Agency simply declares these emissions to be significant. This is arbitrary and capricious.

6.0 EPA MUST INCLUDE A PROVISION IN SUBPART OOOOA TO ENSURE THE TAILORING RULE FRAMEWORK IN THE PSD AND TITLE V PERMITTING RULE APPLY AND THAT METHANE ALONE WILL NOT TRIGGER PSD OR TITLE V PERMITTING

Pollutants that are subject to the prevention of significant deterioration ("PSD") permitting program are identified in EPA's PSD rules in the definition of "regulated NSR [new source review] pollutant." 40 C.F.R. §§ 52.21(b)(50), 51.166(b)(49). That definition has four Subparts, the second of which covers pollutants regulated under section 111. The fourth Subpart covers "[a]ny pollutant that is otherwise subject to regulation under the Act."

EPA's Tailoring Rule limits the number of sources required to obtain PSD permits due to GHG emissions under the *fourth* Subpart of the "regulated NSR pollutant" definition. Similarly, the Tailoring Rule in the Title V rules limits the number of sources required to obtain Title V permits by incorporating the term "subject to regulation" in the definition of major source. After the Supreme Court's decision in *Utility Air Regulatory Group v. EPA*, 134 S. Ct. 2427 (2014) (and subsequent remand proceedings before the D.C. Circuit),[2] part of the original Tailoring Rule remains in effect. A source cannot trigger PSD and Title V permitting requirements solely because of its GHG emissions; only emissions of non-GHG pollutants can trigger PSD and Title V requirements. Moreover, where non-GHG emissions trigger PSD and Title V permitting requirements for a so-called "anyway source," that source's GHG emissions will be subject to PSD and Title V permitting requirements only if the source emits GHGs in excess of 75,000 tons per year of carbon dioxide equivalent.

In the PSD rules, the *second* Subpart of the "regulated NSR pollutant" has no Tailoring Rule equivalent in Part 51 or 52. EPA has recognized this gap and stated it intends to conduct a rulemaking to set a *de minimis* threshold for GHGs that would apply to all four Subparts of the definition for all types of sources. 80 Fed. Reg. at 64630. EPA has not yet conducted a rulemaking to address this issue, however.

[2] Per Curiam Order, *Coal. for Responsible Regulation v. EPA*, No. 09-1322 (D.C. Cir. Apr. 10, 2015), ECF Doc. No. 1546840.

Thus, when EPA finalized NSPS Subpart TTTT, which addresses carbon dioxide emissions from new electric generating units, it included language in Subpart TTTT to make clear that the "anyway" source framework applies to the second part of the "regulated NSR pollutant" definition. Similarly, the EPA included in the language a provision to make clear the "anyway" source framework applies in the Title V regulation as well. *See id.*

EPA must also ensure their action of naming only methane in Subpart OOOOa cannot trigger PSD or Title V permitting and instead that methane should be considered a surrogate for the existing group of six greenhouse gas pollutants. Such a fix was included in the final NSPS Subpart TTTT by adding language to clarify the pollutant being regulated by the Subpart is greenhouses gases in the form of a limitation on emissions of carbon dioxide. A similar clarification should be added to Subpart OOOOa, as well as a discussion in the preamble, to ensure methane on its own cannot cause a source to be considered major for PSD and Title V purposes and that a PSD major modification cannot be caused solely due to an increase in methane emissions.

API proposes the following specific rule language to correct the issue, modeled after NSPS TTTT:

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 emission 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).

(2) For the purposes of 40 CFR 52.21(b)(50)(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 § 52.21(b)(49) of this chapter.

(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.

(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.

As further support for this clarification, in the preamble to the final Subpart TTTT, EPA recognized that EPA "will need to consider adding provisions like 40 CFR 60.5515 to other Subparts of part 60" until it undertakes the broadly applicable rulemaking it is considering. 80 Fed. Reg. at 64630. The Subpart TTTT approach should be taken in Subpart OOOOa because it would confirm in regulatory language that States do not need to amend their existing state implementation plans.

7.0 FOR AFFECTED FACILITIES WHERE REGULATION OF METHANE IN ADDITION TO VOC ACHIEVES NO APPRECIABLE ADDITIONAL REDUCTION IN METHANE EMISSIONS, THERE IS NO NEED OR JUSTIFICATION FOR METHANE OR GHGS TO BE REGULATED.

In the proposed rule, EPA admits that for some of the regulated affected facilities, direct regulation of methane accomplishes no further reduction in methane emissions than would occur through regulation of VOC alone. EPA recognizes that under its proposal, the same controls would be required for VOC and methane as are currently required for VOC under the 2012 NSPS. *See, e.g.*, *id.* at 56610 (explaining standards for centrifugal compressors and pneumatic controllers). EPA acknowledges that for sources in the production and processing segment of the oil and natural gas sector, certain stakeholders (including API) have stated that, as a result, the Agency should rely on VOC standards and not propose redundant methane standards that impose no additional control requirements and result in no additional emissions reductions. *Id.* at 56609. API maintains that position in these comments.[3] There is no rational basis for taking the wholly discretionary action[4] of regulating methane or GHGs from this part of the oil and natural gas sector where EPA would achieve no additional emissions reductions beyond those achieved through existing VOC standards. None of EPA's asserted reasons have merit, and therefore, EPA has not made a showing that revision of the standards is "appropriate," as required under section 111(b)(1)(B). For that reason, EPA must issue a new proposal that presents its rationale for why its revision is "appropriate."

First, EPA generally asserts that because the source category's methane emissions at current levels "contribute substantially to nationwide GHG emissions" and are "expected to increase," methane emissions "cannot be treated simply as an incidental benefit to VOC reduction." *Id.* at 56599. But there will be no further reductions in methane emissions from already-VOC-regulated sources if methane is regulated directly, so additional emissions reductions would not occur vis-à-vis current levels. Moreover, any attempted reliance on future emissions growth is speculative at present and cannot serve as a rational basis. Regulation must be grounded in reality, not hypotheticals.

Second, EPA contends that direct regulation of methane in addition to VOC "promote[s] consistency" such that all affected sources are subject to both VOC and methane standards. *Id.* But this "consistency" accomplishes no benefit in practice. Instead it will increase the compliance burden for affected facilities, without any beneficial environmental or health effect. For that reason, it is distinguishable from the Kraft Pulp Mill NSPS example that EPA cites, where emissions limits of already regulated sources under NSPS Subpart BB "were adjusted downward" to make them consistent with those in Part 63 Subpart S and thereby "ease[the] compliance burden for the sources." *See id.* at 56599 n.8.

EPA has not, and cannot, provide a rational basis for direct regulation of methane because regulation for the sake of regulation is never rational. Congress recognized as much in section 301(a) of the Clean Air Act, where Congress authorized the Administrator only to "prescribe such regulations as are *necessary* to carry out [her] functions." (emphasis added). EPA cannot meet that requirement here.

8.0 EPA'S STANDARDS THAT ACHIEVE NO ADDITIONAL REDUCTION IN EMISSIONS CANNOT MEET THE REQUIREMENT TO CONSIDER THE COST OF EMISSIONS REDUCTIONS.

As noted above, by EPA's own admission, the regulation of methane emissions from sources already regulated under Subpart OOOO for VOC emissions will achieve no additional emissions reductions. EPA therefore cannot meet the requirements for determining the "best system of emission reduction" (BSER) that the CAA requires.

EPA must "tak[e] into account the cost of achieving [emissions] reduction" in its BSER determination. CAA § 111(a)(1). Sources already regulated under Subpart OOOO for their VOC emissions will achieve

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[3] In the proposed rule, EPA "anticipates … stakeholders will express their views during the comment period." 80 Fed. Reg. at 56609.

[4] EPA recognizes that the regulation of additional pollutants is discretionary. *Id.* at 56599 & n.7.

zero additional emissions reduction and yet will incur additional costs to comply with new methane requirements. EPA cannot determine a standard to be BSER where it imposes costs yet achieves no reduction. That would be *per se* cost-ineffective.

9.0 THE PROPOSED RULE IS ARBITRARY AND CAPRICIOUS BECAUSE EPA FAILED TO CONSIDER THE IMPLICATIONS OF SECTION 111(D) OF THE CLEAN AIR ACT

EPA interprets section 111(d) of the Clean Air Act to apply to existing sources that would be regulated under a section 111(b) NSPS if the source were new, provided the source category and/or pollutant is not otherwise regulated under section 108 or 112 of the Act. *See* 80 Fed. Reg. 64662 (Oct. 23, 2015) (EPA's "Clean Power Plan" to regulate carbon dioxide emissions from existing electric generating units).[5] Under EPA's interpretation, final promulgation of the proposed rule would trigger an obligation for the Agency to issue emissions guidelines for existing oil and natural gas sources under section 111(d).[6] Assuming, for the sake of argument, that EPA's interpretation were permissible, the proposed rule should have to consider section 111(d) impacts. Yet, the proposed rule includes no reference at all to section 111(d) and no discussion of the potential regulatory implications to existing sources under section 111(d) by promulgating a NSPS for the oil and natural gas sector under section 111(b). As is plainly evident from the Clean Power Plan, regulation of existing sources under section 111(d) can and likely would have far greater potential impacts than the proposed standard for new sources. As a result, the Agency should have estimated the costs of regulating existing oil and natural gas sources in the proposed rule given its interpretation of the Act. EPA's utter failure to consider this important aspect of the decision to implement a NSPS renders the decision arbitrary and capricious. *See Motor Vehicle Mfrs. Ass'n v. State Farm Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) ("Normally, an agency rule would be arbitrary and capricious if the agency has … entirely failed to consider an important aspect of the problem….").

While EPA should have considered the impacts of the regulation of existing sources under section 111(d) as part of the proposed rule. The Clean Air Act does not impose a deadline on the Agency to propose emissions guidelines pursuant to section 111(d) once it has promulgated standards of performance for new sources under section 111(b). *See* CAA § 111(d). Moreover, because the proposed rule is legally flawed for the reasons described elsewhere in these comments, EPA would have no authority to adopt section 111(d) guidelines for oil and natural gas sources because the regulations under section 111(d) must apply only to "any existing source for any air pollutant . . . to which a standard of performance under this section would apply if such existing source were a new source." *Id.* § 111(d)(1)(A).

[5] EPA's interpretation will be challenged in litigation over the Clean Power Plan. *See West Virginia, et al. v. EPA*, No. 15-1363 (D.C. Cir.).

[6] API does not agree with EPA's interpretation of the statute presented in the Clean Power Plan that the Agency has authority to issue § 111(d) standards for affected facilities that are subject to § 112 standards. Rather, API asserts that if a source category is regulated under § 112, then EPA cannot regulate sources in that source category under § 111(d). *See* CAA § 111(d)(1)(A)(i). Because § 112 standards apply to the oil and gas sector, EPA lacks authority to issue § 111(d) standards for this sector.

10.0 EPA'S COST METHODOLOGY IS INCONSISTENT WITH ITS OWN "RATIONAL BASIS" TEST AND IS THEREFORE ARBITRARY AND CAPRICIOUS.

For some sources in the proposal, EPA finds that "cost-effective controls that can simultaneously reduce both methane and VOC emissions from . . . equipment . . . would *not occur* were we to focus solely on VOC reductions." 80 Fed. Reg. at 56599 (emphasis added). This methodological cost justification for regulating methane is inconsistent with EPA's own test for regulating an additional pollutant from a source category and is thus arbitrary and capricious.

In the proposal, EPA uses two different methodologies for assessing whether costs are reasonable. *Id.* at 56617. Under EPA's single pollutant approach, all of the costs are attributed to only one pollutant (i.e., methane or VOC) because the same controls are used for VOC and methane. *Id*. Under the second approach—known as the "multipollutant cost-effectiveness" approach—the annualized costs are apportioned based on the relative reduction of each pollutant by a control. *Id.* If application of either the individual pollutant approach or the multipollutant cost-effectiveness approach results in a determination that regulation imposes reasonable costs, EPA concludes that control is cost-justified. For at least certain sources, EPA justifies controls based on the multipollutant approach alone, as the costs evaluated under the single pollutant approach would not be reasonable.[7]

EPA's reliance on the multipollutant methodology is arbitrary and capricious because it is inconsistent with EPA's own "rational basis" test for determining whether regulation of an additional pollutant from a source category is appropriate. As EPA clearly states, under its "rational basis" test, the Agency must have a rational basis for regulating *each* "pollutant." *See* 80 Fed. Reg. at 56601. EPA's multipollutant approach is inconsistent with that test because it allows the Agency to find that regulation of multiple "pollutants" is reasonable where regulation of each pollutant individually would not be. *See id.* at 56636.

11.0 EPA SHOULD NOT REQUIRE THE USE OF ELECTRONIC REPORTING UNDER SUBPART OOOO AND SUBPART OOOOA.

On March 20, 2015, EPA proposed the "Electronic Reporting and Recordkeeping Requirements for New Source Performance Standards'' (80 FR 15099, March 20, 2015). EPA should not require the use of electronic reporting under Subpart OOOOa since the system is not yet established and application of EPA's Compliance and Emissions Data Reporting Interface (CEDRI) to the oil and natural gas industry has unique challenges.

As mentioned in our June 18, 2015 comment letter on EPA's proposed requirements for electronic reporting, the proposed electronic reporting approach is in conflict with Subpart OOOO (and proposed Subpart OOOOa) requirements. As a result, a requirement to use EPA's electronic reporting tool should not be finalized at this time. Given the overlapping relevance to the unique challenges under Subpart OOOOa for electronic reporting, a copy of our June 18, 2015 comments is included as Attachment B.

EPA is proposing that the annual reports required by this Subpart be submitted through CEDRI starting 90 days after a template is available. Because of the unique operations of this industrial category, we see several problems with applying CEDRI as proposed, and API requests that these concerns be resolved before these new requirements are finalized for Subpart OOOO or Subpart OOOOa.

[7] API's review of the proposed rule finds only one such example—EPA's determination that a semi-annual monitoring and repair program for fugitive emissions at well sites imposes reasonable costs under the multipollutant approach but not under the single pollutant approach. 80 Fed. Reg. at 56636.

Under this proposal the Subpart OOOO and Subpart OOOOa annual reports required by §60.5420(b) and §60.5420a(b) respectively must be submitted electronically once a template is available. Under Subpart OOOO and Subpart OOOOa, each regulated item is treated as a separate affected facility; however, they are reported together in the annual report. The individual affected facilities are identified in the annual report in different ways (often by their latitude and longitude) but not necessarily by the site where they are located, since there often is no site address and the affected facility (e.g., well) may be the only thing at that location. That is why Subpart OOOO does not require that all types of affected facilities be linked with a particular site (e.g., Subpart OOOO requires wells and storage tanks be identified by their longitude and latitude).

As we understand it, the CEDRI system links reports to the site at which they are located. Identifying each site separately in CEDRI would require deconstruction of the annual report as currently specified in Subpart OOOO (a change which was not proposed), imposing very large unjustified burdens that have not been considered and that are inconsistent with the promulgated reporting requirements of Subpart OOOO. For instance, one member company reports they have approximately 8,000 such sites and another member reports upwards of 20,000 sites. Although not all of the sites currently require reporting under Subpart OOOO, there may be hundreds of thousands of sites in petroleum upstream operations as new wells are drilled and new equipment is added to existing sites.

The CEDRI requirement to link every affected facility to a site could therefore require thousands of reports and responsible official certifications for each current Subpart OOOO report.

API, therefore, requests that the CEDRI system be modified to accept Subpart OOOO and OOOOa annual reports as currently specified in §60.5420 of Subpart OOOO and not require linking the reports to particular sites and that the proposed amendments of Subpart OOOO and Subpart OOOOa not be finalized until those revisions are completed.

Subpart OOOO and Subpart OOOOa require that the annual report be certified, as does the CEDRI system, however, these Subparts have a specific definition of "certifying official" that is different from the definition on the CEDRI webpage, and API therefore requests that the final revision to Subpart OOOO clarify that the certifying official for CEDRI reports is the one defined in §60.5430 of Subpart OOOO and §60.5430a of Subpart OOOOa. Furthermore, no additional certifications should be required than are currently required by Subpart OOOO or Subpart OOOOa without notice and comment rulemaking that addresses this specific issue.

For these reasons, API asks that EPA make CEDRI system and Electronic Reporting Tool (ERT) allowed alternatives to submitting hardcopy or PDF reports, at least for several years, until all of the operability and integration issues can be resolved.

As part of time afforded under a phase-in approach discussed above, API is committed to work with EPA on mechanisms to efficiently enable use of the CEDRI system for the oil and natural gas industry (e.g. develop mechanisms to support reporting of multiple affected sources at a time as is currently done on a regional basis by operators).

12.0 THE CONTROL DEVICE TESTING AND MONITORING COMPLIANCE ASSURANCE REQUIREMENTS ARE NOT APPROPRIATE

12.1 Oil and Natural Gas Production Sites are Unique from Traditional Stationary Sources

The sources covered by the current Subpart OOOO and the proposed Subpart OOOOa, particularly those in the production segment, are unique from typical stationary sources covered by NSPS in that they are small sites, located in remote areas, dispersed from each other (often requiring an hour or more travel time between regulated sites), and typically unmanned. These sites lack the infrastructure of power, communication or even a simply found geographic address that are required to make many of the historic compliance assurance measures function. Because EPA has "force fit" the testing, monitoring, and other compliance assurance requirements designed for traditional stationary sources to the oil and natural gas industry, the proposed testing and monitoring requirements result in unnecessary burden without a commensurate benefit. Sections 12.1.1 through 12.1.3 briefly describe some of the unique aspects of the oil and natural gas industry. Sections 12.2 and 12.3 provide specific examples of the inappropriateness of these requirements and provide recommendations that will ensure compliance and environmental benefit without creating unnecessary and costly burdens on the industry.

12.1.1 Oil & Gas Production Operating Conditions are not Steady State

Oil and natural gas operations are unique due to the dependence on the naturally occurring underground nature of the resource being harvested. This section summarizes some of those unique characteristics and the impact on emission control devices (primarily combustion control devices).

Unlike most industrial sectors where operating conditions are defined in the engineering stage, the oil and natural gas production sector does not operate at steady state conditions. Equipment design must be tailored to the conditions and fluid compositions supplied by the reservoir. Oil and natural gas is located thousands of feet below the surface and must flow in two or three phases to the surface. Ideally, this flow would occur at a relatively steady rate at a velocity fast enough to suspend small droplets of produced water and liquid hydrocarbons during the vertical ascent to the surface. The mixture is then separated in the two or three phase separator with steady pulses of produced water sent from the bottom of the separator to its storage vessel, hydrocarbon liquids off the middle to its storage vessel, and natural gas off the top of the separator to the gathering system. This may occur at times but it is not typical.

As production declines and velocity in a vertical pipe decrease, the small droplets start to move slower than the gas and combine into larger and larger droplets. These eventually form slugs of liquid that must be pushed up the pipe. The increasing back-pressure on the reservoir reduces in-flow, production, and hence velocity. As backpressure on the reservoir increases and the velocity continues to decrease, the liquid column in the wellbore can stop the gas flow until the gas pressure below the slug increases sufficiently to push the liquid to the surface. The management of these wellbore liquids is a major concern throughout the life of a well that mandates changes in both down hole and surface equipment. The impact to environmental emissions controls is that flow to the control device varies from essentially zero to high flow rates and quickly back to zero rapidly and often. This highly variable, non-steady state flow mandates equipment to be sized much larger than ideal steady state conditions would dictate and makes flow measurement infeasible.

12.1.2 Production Separator Operation

The purpose of the two or three-phase production separator is to separate the two or three-phase flow from the well, to ensure that only natural gas goes to the gathering system and to ensure only liquid hydrocarbons and produced water are sent to their respective storage vessels. Separators are sized to give sufficient "residence time" to allow the separation of phases to take place. Since the actual mix of gas, oil (or condensate), and produced water varies randomly with time, it is impossible to predict when or how often a given control-action will occur.

The flow into the separator is made up of the fluids that the reservoir produces at any given moment, as modified by the transport of those fluids to the surface. The liquid levels in the separator are maintained by valves (often called dump valves) on the separator outlets to the oil/condensate storage vessel and the produced water storage vessel (although liquid collection systems are sometimes used in lieu of a storage vessel). The dump valves are sized to handle the highest flow rate of liquid that the separator can be expected to receive. Because of the highly variable flow conditions, separators normally provide flow to storage vessels in short spurts, typically lasting only seconds, to maintain the required liquid levels, and dump cycles may be separated by many minutes, hours, or even days.

12.1.3 Closed Vent System Flow Rate

Gas flow from the storage vessel into the closed vent system (CVS) predominantly results from flashing vapors (resulting from the spurts of liquids from the separator) and dwarfs the working and standing emissions typical from storage vessels (that occur between spurts). However, the CVS and control device must be sized sufficiently to handle the peak vapor volumes expected. Measuring the flow in CVS causes two distinct problematic issues. The normal volumes from working and standing losses and the flashing of separator liquids are at very low velocities that are hard to measure with current measurement technology (see Technical Review of Western Climate Initiative Proposals to Meter Fuel and Control Gas, Attachment C). Measuring the flow of flash vapors and peak flow rates would require a device that can go from zero flow to maximum flow in milliseconds and be able to go back to zero just as quickly. The hysteresis (i.e., the amount that the previous state impacts the future state) and the latency (i.e., the time required to return to steady flow after a transient) of the very best commercial measurement devices available today are both inadequate for millisecond-scale transients. Currently for minerals accounting purposes the Federal Government and States do not require flow measurement for liquids but only gaging or strapping of the tank because of the lack of adequate measurement technology.

12.2 The Proposed Testing, Monitoring, and Other Compliance Assurance Requirements are Inappropriate for the Oil and Natural Gas Industry

12.2.1 The NESHAP-Level Approach For Compliance Assurance Is Inappropriate And Unrealistic For Oil And Natural Gas Production Sites

For the most part, EPA has copied the full MACT control device and compliance assurance requirements in NESHAP HH (40 CFR 63, Subpart HH) for Subpart OOOOa rather than craft cost-effective requirements tailored to address the unique situations related to oil and natural gas operations. The capital cost of the control device is trivial in comparison to the cost of the performance tests, monitoring, recordkeeping, etc. for complying with NESHAP HH. These ongoing operating and maintenance costs were not adequately considered by EPA in the cost effectiveness determination for Subpart OOOOa. Furthermore, Subpart OOOOa applies to dispersed locations that do not have electricity, may not have automation and may have limited space for existing automation to accept additional inputs into their programmable logic controller (PLC) and remote transmitting unit (RTU) space. Although it may be appropriate to evaluate control devices similar to those found in NESHAP HH major sources, it is not appropriate to arbitrarily invoke compliance assurance requirements intended for the maximum control of hazardous air pollutants (HAPs) as the standard for an NSPS regulation for the control of volatile organic compounds (VOCs) or methane.

Examples of the inappropriateness of invoking MACT compliance assurance requirements for NSPS include but are not limited to:

- §60.5417a(a) requires Continuous Parameter Monitoring System (CPMS) for control devices. EPA did not include the cost for installing, maintaining, and operating a CPMS in any of the impact assessments for this rulemaking. Most affected facilities in the production segment of the industry will be located in remote areas without available electricity or limited remote transmitting unit (RTU) space. In addition, a programmable logic controller (PLC) is often needed to record, average, and analyze the large amounts of data to determine if a parameter is exceeded, resulting in activation of a control system or signal for site visit evaluation. The calibration, maintenance, and repair of a CPMS requires specialized crafts knowledgeable in instrumentation and controllers. This work cannot be performed by lease operators during normal inspection visits.

- §60.5417a(f)(1) requires the operator to establish minimum and/or maximum values for the operation parameter and operate the control device within the range. As explained in section 12.3.4, this requirement is impractical to meet for either manufacturer certified combustors or combustion controls where the performance test is performed in the field, but for different reasons. This requirement is the same as the NESHAP HH requirement located in §63.773(d)(5)(i)(a) & (c).
- Similar to above, §60.5417a(d)(1)(iii) requires that a flare pilot, used for centrifugal compressors and pneumatic pumps controls, be assured by a heat detection sensor and continuous controller. Section 60.5417a(a) makes this appear to be a CPMS requiring all of the assurance provisions of (c), (f) and (g). This requirement is essentially identical to the one in §63.773(d)(3)(i)(C) with the CPMS general provisions located §63.773(d)(1) requiring to meet (4), (6), & (7). Requiring a pilot monitoring device to meet the requirements for a CPMS is extremely burdensome for any rule but is unprecedented for NSPS regulations.
- Compliance Demonstrations (§60.5412a) and Test Methods (§60.5413a). EPA reference methods that determine percent reduction on a mass basis, as is specified in Subpart HH major source control requirements where Subpart OOOOa does not specify percent reduction of a pollutant on a mass basis. This causes the measurement of volume that is not practical or in many cases possible with the types of operations and fluid flows typical for these facilities.

12.2.2 Compliance Assurance Requirements Are Unnecessarily Complex

The use of extensive cross referencing both between sections concerning control devices (i.e. §60.5412a for initial compliance requirements, §60.5413 for performance testing, and §60.5417a for continuous monitoring requirements) and various test methodologies renders the requirements confusing and nearly impossible to follow. These segmented requirements unnecessarily add to the compliance burden and are likely to lead to errors and misunderstanding. Companies that operate stationary sources subject to EPA's NSPS and NESHAP regulations may have personnel whose sole job is to understand EPA's complex requirements. However, many companies regulated by Subpart OOOOa are primarily small businesses that do not have this luxury. API members, along with the consultants they have hired, have had difficulty in interpreting the requirements for control devices as proposed. There is still not agreement of interpretation within API with many of the provisions.

12.2.3 API Agrees With EPA's Proposal To Maintain The Streamlined Monitoring Requirements For Storage Vessels But Disagrees With The Proposed Addition Of Performance Testing Requirements

During the "reconsideration" of Subpart OOOO (proposed April 12, 2013, finalized September 23, 2013 and continued until this proposal), EPA found that "compliance monitoring provisions and field testing provisions of the final rule may not be appropriate for this large number of affected storage vessels, which is much greater than we had expected and with many in remote locations." Further, EPA found it appropriate to only include "streamlined monitoring and continuous compliance demonstration requirements to provide assurance" (see 78 FR 22134). The streamlined monitoring provisions consisted of monthly sensory (i.e. OVA) inspections and monthly observation for visible smoke emissions employing section 11 of EPA Method 22 for a 15 minute period.

In this proposal, EPA has retained the "streamlined monitoring provisions" (see §60.5412a(d)(1)(i) through (iii)). Despite the fact that nothing has changed since 2012 with regard to the number of storage vessels and their remote location, EPA reinstated the performance testing without responding to most of the concerns raised during the reconsideration process. API supports EPA's decision to maintain the "streamlined monitoring provisions" in lieu of most of the continuous monitoring requirements finalized in 2012. Additionally, API appreciates and supports EPA's revision to the outlet concentration compliance method of §60.5412a(d)(1)(iv)(B) raising the TOC (minus methane and ethane) level from 20 ppmv to 600 ppmv. However, EPA did not address API's significant concerns regarding the percent pollutant reduction method of §60.5412a(d)(1)(iv)(A) or any of the performance testing provisions of §60.5413a or continuous monitoring provisions of §60.5417a. API continues to believe that unaddressed provisions are unnecessarily complex and stringent.

12.2.4 The Compliance Assurance Requirements For Centrifugal Compressors Are Not Justified

During discussions with EPA, API was told that the control device monitoring and testing requirements of the 2012 rule were retained since few centrifugal compressors were expected to require control and that most of these affected sources would be located at more developed facilities, such as Natural Gas Processing Plants. While this statement may sufficiently explain the retention of some of the monitoring provisions, it does not address the practical considerations in complying with the performance test provisions and the identifying parameter ranges required for the continuous monitoring. Although there are a few centrifugal compressors that require control, almost all of the control devices also control gases from other sources, such as storage vessels, that bring in the impracticality of flow measurement discussed in Section 12.1.3.

12.2.5 The Proposed Compliance Assurance Requirements For Pneumatic Pumps Are Filled With Problems

There are many issues with the proposed compliance assurance provisions for pneumatic pumps. Following are three major issues associated with the compliance assurance requirements. These are discussed at length in Section 24.0.

Compliance Assurance Requirements of an Existing CVS/Control Device Should Not Change

EPA determined that the benefit of controlling the discharge of a pneumatic pump was insufficient to justify the installation of a control device, thus the requirement to only connect new pneumatic pumps to existing CVS/control device. Further, EPA only considered the cost of piping the pump discharge to the CVS but did not include costs for additional compliance assurance (see Section 22.2.1 – 24.3.1). Most control devices are expected to be installed due to state minor source NSR permits. These permits have their own compliance assurance requirements which are significantly different than those for OOOOa centrifugal compressors, resulting in significant additional cost. These additional costs have not been included in EPA's cost/benefit analysis, cannot be justified with the low emission reduction benefits achieved, and do not provide additional environmental benefit. Thus, API recommends that EPA not any require additional compliance assurance requirements in OOOOa be applied for a CVS or control device when a pneumatic pump is connected to it (see Section 24.2).

Pneumatic Pumps Are Located Near Storage Vessels, Not Centrifugal Compressors

As stated above, EPA believed that few centrifugal compressors were expected to require control, and these few are mainly expected to be at natural gas processing plants. Therefore, EPA proposed that pneumatic pumps at natural gas processing plants must have no natural gas emissions, thus tying centrifugal compressor compliance assurance requirements to pneumatic pumps is not logical. However, pneumatic pumps are most often located at well sites and small compressor stations that are more likely to have controls devices installed to control emissions from storage vessels. Well sites do not have the communications infrastructure that would be required to be installed under the centrifugal compressor compliance assurance requirements (see §60.5417a(a)) making these additional requirements an even greater burden. As noted above, API believes that no additional compliance assurance requirements should be added beyond what are already required for the existing control device. However, if EPA decides to add new compliance assurance requirements when a new pneumatic pump is connected to an existing control devise, it should be the storage vessel compliance assurance requirements, not those for centrifugal compressors.

Clarification is Needed When a Pneumatic Pump Must be Connected to a CVS/Control Device

There is significant uncertainty on when a pneumatic pump must be connected to a control device. Control device is an undefined term and defining it is a necessary first step to resolve this issue (see Sections 13.0) . Another great source of uncertainty is when a boiler or process heater is considered a control device and when it is part of a process (see Section 13.0). API believes that pneumatic pumps should not be required to be routed to a boiler or heater.

Further, the control device and the pneumatic pump may be owned/operated by two different companies (i.e. chemical injection for gathering system corrosion control at a well site). In this case, even though a control device is at the location, it is not available to the owner/operator of the pneumatic pump (see Section 24.4.5). Finally, instances occur where it is not technically feasible to connect the pneumatic pump to the control device (see 24.3.2).

12.3 Compliance Assurance Requirements for Combustion Control Devices

12.3.1 The Proposed Compliance Assurance Requirements May Discourage The Use Of Enclosed Combustors

The design of enclosed combustors intrinsically yields higher destruction efficiencies than flares because of the heater style of burner and protection from cross wind. The enclosure also creates an induced draft of air that aids complete combustion of heavier (higher molecular weight) hydrocarbon streams. Additionally, the enclosure isolates the flame from sight that may cause concern to some members of the public. These benefits sometimes encourage industry to install the high cost internal (i.e., "enclosed") combustor instead of the commonly used open flame flare. Enclosed combustors do have the ability to be performance tested where the open nature of flares do not. It is ironic that EPA is requiring substantially more burdensome monitoring and performance testing requirements for enclosed combustors in the proposed rule even though these combustors have greater environmental benefit than flares. It is counterproductive for the environment to disadvantage enclosed combustors with compliance assurance requirements just because they are technically feasible. EPA should encourage the use of enclosed combustors by using the same visual inspection requirements as with flares for opacity.

12.3.2 The Continuous Parameter Monitoring System (CPMS) Provisions For Centrifugal Compressors And Pneumatic Pumps Are Inappropriate

API supports the EPA's proposal to not require CPMS or other monitoring systems on storage vessel combustion control devices. As will be discussed below, API does not understand the value of the CPMS requirements that are proposed for combustion control devices for centrifugal compressors and pneumatic pumps. Installing and operating a continuous pilot and the use of visual inspection for opacity (as required for storage vessel affected facilities in §60.5412a(d)(1)(ii) & (iii)) is adequate to assure complete combustion and encourages the use of enclosed combustors. The only additional compliance assurance procedure should be to check the air vent per manufacture recommendations any time opacity is seen (as required in §60.5417(h)(1)(A)).

12.3.3 The Determination Of CPMS Range Determinations In Field Performance Test Is Technically Impractical

Section 60.5417a(f)(1) requires that for any parameter that requires CPMS monitoring, the operator must determine the minimum or maximum value of the parameter that continuously achieves the performance requirements in §60.5412a(a). Section §60.5417(f)(1)(i) requires a performance test performed by the operator to determine the minimum or the maximum operating parameter based values measured during the performance test. However, the operator has limited ability to adjust the conditions of the process to test the control device. The performance test must be run at the conditions available when the test is scheduled. The operator is unable to vary the operating conditions to determine the limit of the operating parameter as a manufacturer does when conducting a shop test on an enclosed combustor. Section 60.5417a(f)(1)(i) cannot practically be complied with, because the performance test cannot be completed at the full range of conditions for which the control device will be operated. Furthermore, this extends far beyond what EPA requires for testing control devices at area sources under NESHAP HH, which applies to nearly all oil and natural gas production sites. In fact, the requirements approach the NESHAP HH requirements for major sources like natural gas processing facilities. For NSPS at a remote, unmanned site, it is more reasonable to test the device during current operating conditions.

12.3.4 It Is Not Technically Feasible To Meet The CPMS Flow Measurement Requirements For Manufacturer Certified Combustion Control Devices

Paragraph 60.5417a(f)(1)(iii) requires that for manufacturer certified enclosed combustors, an operator must install CPMS measurement on the inlet flow to assure that the flow is not greater than the maximum or less than the minimum that the manufacture specifies. The CPMS requirements only apply to centrifugal compressors (that have relatively stable flow rates) and pneumatic pumps, but the same control devices will often be controlling emissions from storage vessels as well. As explained in section 12.1.3, the measurement of flow from storage vessels is very difficult even when only the normal emissions must be measured. Requiring both the minimum and maximum range to be measured, it is doubtful if a single instrument can measure both values. The pump flow as well is intermittent, low pressure, low velocity/flow and difficult to measure as discussed in Section 24.0.

12.4 Compliance Options For Combustion Control Devices

Section §60.5412a specifies four compliance options that can be used to assure compliance with the control requirements of storage vessels (see §60.5412a(d)(1)(iv)) and centrifugal compressors and pneumatic pumps (see §60.5412a(a)(1)). These options include (1) percent reduction of the pollutant, (2) limiting the concentration in the exhaust, (3) maintaining a minimum combustion zone temperature, and (4) inject the stream into the flames zone of a boiler or process heater. Comments are provided below on options 1 and 2. As explained in Section 13.0 below, option 4 is a direct conflict with the definition of "route to a process" in both Subparts OOOO/OOOOa and NESHAP HH. Therefore, API recommends that EPA remove §60.5412a(a)(1)(iv) and §60.5412a(d)(1)(iv)(D).

12.4.1 Percent Reduction Of Pollutant Should Be Based On Volume Not Mass And Should Not Requirement Measurement of Flow To The Control

The standards for centrifugal compressors, pneumatic pumps, and storage vessels each require a percent reduction.

- For centrifugal compressors, §60.5380a(a)(1) requires that methane and VOC emissions be reduced by 95.0 percent or greater
- For pneumatic pumps, §60.5393a(b)(1) requires that natural gas emissions by 95.0 percent, and

- For storage vessels,§60.5395(a)(2) requires that VOC emissions be reduced by 95.0 percent

Note that none of these standards specify the basis for the 95.0 percent reduction. However the initial compliance demonstration requirements in §60.5412a(a)(1)(i) for centrifugal compressors and pneumatic pumps and in §60.5412a(d)(1)(iv)(A) for storage vessels add the requirement that this percent reduction in emissions be determined on a mass basis. The associated performance test requirements of §60.5413a(b)(3) for calculating percent reduction by weight of pollutants requires the measurement of flow to the control device. The requirements of §60.5412a and §60.5413a were predominantly adopted from the major source NESHAP requirements in Subpart HH that specify control requirements of 95 percent reduction by weight. While mass reduction requirements may be appropriate and specified by Subpart HH, they are burdensome and impractical for NSPS requirements for small, remote, dispersed and unmanned production facilities.

Section 12.1.3 above describes the many difficulties encountered when attempting to measure the flow of vapors to a control device at oil and natural gas production sites. EPA has not explained the reason for prescribing the reduction of pollutants to be determined by weight in the compliance demonstration and performance testing requirements when a mass destruction was not specified as part of the control requirements. Conditions of intermittent high/low flow conditions, variable and turbulent flow, and variable temperature and pressure make it infeasible to perform the test methods in the production field that are typically used in refineries or chemical plants. Coupled with the dispersed and remote nature of the small sources regulated under this rule, the proposed requirements are not appropriate and are unnecessarily burdensome. API requests EPA to determine percent of TOC reduction through a carbon balance methodology similar to that described in EPA's Flare Efficiency Study Report.[8]

The requirement in §60.5413a(b)(3)) should be modified to require reduction of TOC emissions by 95% on a volumetric concentration basis using a "carbon balance" methodology for analysis of the exhaust stack effluent from an "enclosed combustion device" being used as a control device to demonstrate reduction efficiency.

Methodologies 25A for TOC (calibrated to propane), 3A for CO_2 and O_2, and 10 for CO should be specified for testing of the stack effluent gas. The CO_2 measured using Method 3A should be adjusted downward by the latest published atmospheric CO_2 concentration, as reported from the Mauna Loa monitoring site by NOAA's Earth System Research Laboratory, multiplied by the ratio of O_2 measured in the stack effluent as compared to the ambient O_2 content of 20.8 volume %. (3A measured CO_2 (ppmv) – (Mauna Loa Concentration (ppmv) X (3A measured O_2 (ppmv)/208,000 (ppmv) ambient O_2 concentration).

The percent pollutant reduction or destruction efficiency of 95% would be demonstrated when the following equation yields a value of 95% or greater:

$(CO_{2c} + CO)/(CO_{2c} + CO + (3 * TOC))$

Where:

CO_{2c} = CO_2 ppmv concentration measured in the stack via method 3A minus the ambient CO2 ppmv concentration present in the stack determined as described above.

CO = CO concentration measured in the stack via method 10

[8] . Technical Report "EPA-600/2-83-052" "FLARE EFFICIENCY STUDY" by Marc McDaniel, July 1983 (see http://www3.epa.gov/ttn/chief/ap42/ch13/related/ref_01c13s05_jan1995.pdf).

TOC = Total Organic Carbon, expressed as propane, measured in the stack via method 25A

The following Table 12-1 shows this calculation and outcome for an assumed stack effluent composition:

Table 12-1 Assumed Stack Effluent Composition

Outlet CO_2	30,000	Measured Value
Outlet CO	100	
Outlet TOC	30	
Outlet O_2	150,000	
Ambient O_2	208,000	
Ambient CO_2	388	
Outlet CO_{2c} from combustion	29,720	Outlet CO_2 - ((Ambient CO_2 X (Outlet O_2/Ambient O_2))
Destruction Efficiency	99.70%	$(CO_{2c} + CO)/(CO_2c + CO + (3*TOC))$

12.4.2 API Supports EPA's Revision Of The Concentration Of Exhaust Limit To 600 PPMV

In response to "reconsideration petitioners", EPA proposed to revise the combustion device compliance option of demonstrating an exit concentration of less than 20 ppmv to 600 ppmv as propane (see §60.5412a(a)(1)(ii) and §60.5412a(d)(1)(iv)(B)) as being more representative of a 95% reduction in VOC. EPA solicited comments on this proposed amendment (see 80 FR 56645). API agrees that an exit concentration of 600 ppmv is more representative of a 95% destruction efficiency and supports this proposal.

12.5 EPA Must Revise The Provisions Related To Flares Subject To §60.18

API has several issues with the requirements in Subpart OOOO and proposed Subpart OOOOa that are related to the requirement that flares used as control devices meet §60.18 of the general provisions. One these issues, which is addressed in Section 12.5.2, is related to the inadequacy of the requirements related to flares for storage vessel affected facilities. There are also many technical challenges that make is infeasible to comply with the §60.18 provisions that occur both at production sites and natural gas processing plants. These issues, along with recommended regulatory changes, are discussed in sections 12.5.2 through 12.5.6.

12.5.1 The Proposed Requirements For Flares Are Inconsistent And Inadequate, Particularly As They Apply To Storage Vessel Affected Facilities

The proposed regulatory compliance requirements, with respect to flares and their conformance to §60.18 of the General Provisions of 40 CFR part 60, are reasonably clear for centrifugal compressor affected facilities. The construction of those requirements in Subpart OOOO both generally results in adoption of §60.18(b) requirements for flares yet innovatively allows flexibility to adopt new or superior flare technologies through performance testing. However, this is not true for storage vessel affected facilities. Clarity for applicable requirements, with respect to flares and their conformance to §60.18, for storage vessel affected facilities could be accomplished in a similar manner.

For example, §60.5412(a)(3) of Subpart OOOO clearly identifies a flare designed and operated in accordance with the requirements of §60.5413(a)(1) as an acceptable control device for centrifugal compressors affected facilities. However, there is no analogous allowance of the use of a flare as an acceptable control option in §60.5412(d) for storage vessel affected facilities. An addition to §60.5412(d) of a requirement, similar to §60.5412(a)(3), specifying that a flare must be designed and operated in accordance with the requirements of §60.5413 would result in the same clarity for storage vessel affected facilities. An additional sentence could be added to the introductory paragraph in §60.5413 to say that the performance test exemptions for flares in §60.5413(a)(1) are applicable to both storage vessel and centrifugal compressor affected facilities. The change recommended above to the introduction to §60.5413 is necessary without regard to the flare provisions as the requirements in §60.5413(d) and (e) for manufacturer tested devices also apply to storage vessel affected facilities.

Similarly, for Subpart OOOOa, an addition to §60.5412a(d) of a requirement, similar to §60.5412a(a)(3), specifying that a flare must be designed and operated in accordance with the requirements of §60.5413a would carry the clarity for storage vessel affected facilities to Subpart OOOOa. An additional sentence in the introductory paragraph in §60.5413a is unnecessary because it includes applicability to centrifugal compressor affected facility, pneumatic pump affected facility, and storage vessel affected facility as proposed.

These changes would result in clear and appropriate requirements for flares used as control devices for storage vessel affected facilities. Specific recommendations for these amendments are provided in Section 12.5.6.

While the recommendations above will provide clarity that flares are acceptable control devices for storage vessel affected facilities, as well as clarify the requirements of these flares, there are numerous issues associated with the broad application of the provisions of §60.18 to flares to Subpart OOOO and OOOOa affected facilities. These issues are discussed in the following sections. Additional regulatory recommendations are provided to rectify these problems and allow the continued use of flares in the oil and natural gas industry.

12.5.2 There are Technical Challenges in Meeting the §60.18 for Flares in Oil and Natural Gas Production and Gas Processing that Must be Addressed

Flares are an attractive control device choice for the oil and natural gas industry due to their simplicity, reliability, lower maintenance requirements, and effectiveness in reducing organic compound emissions. The requirements in §60.18 of the 40 CFR part 60 General Provisions were developed by EPA to generally apply to flares. However, these requirements were developed and refined based on industrial flares primarily used at large petroleum refineries and petrochemical plants. As discussed above in section 12.1, there are unique aspects of the oil and natural gas industry that require accommodations in the control device requirements. The following sections suggest changes related to the application of the §60.18 provisions to Subpart OOOO and OOOOa affected facilities that will allow the compliant use of flares in the oil and natural gas industry without compromising their effectiveness in reducing VOC and methane emissions.

12.5.3 The Use Of Electronic Ignition Systems Should Be Allowed

§60.18(c)(2) requires that flares be operated with a flame present at all times, as determined by monitoring using a thermocouple or any other equivalent device to detect the presence of a flame. API continues to believe that an option to use electronic ignition systems should be allowed for the oil and natural gas sector. Since oil and natural gas operations are not always steady state, flares with continuously lit pilots (24/7) can unnecessarily burn and waste fuel gas for the pilot while causing unnecessary emissions when there is otherwise no emission stream being burned. An attractive and effective alternative is to allow the use of electronic ignition systems that ensure a flame is present whenever emissions are being routed to the flare.

In addition, many oil and natural gas production sites are remote and unmanned. In these situations, an electronic ignition system has proven to be a more reliable means of ensuring there is always a flame when emissions are routed to the flare rather than attempting to maintain a continuous pilot.

In the Natural Gas STAR program, EPA published a Partner Recognized Opportunity (PRO) in PRO Fact Sheet No. 903.[9] Presumably this was published because EPA approves of the design, recognizes its benefits and wanted to promote its use in industry. EPA should not forfeit the benefits of this control technology enhancement by disallowing its use. As an established and preferred technology by EPA in the Natural Gas STAR program, operators should not have to petition EPA for approval.

API recognizes the need to ensure that the electronic ignition system is working and that a flame is present at all times when emissions are being routed to the flare. API believes that the existing requirements in §60.18(f)(2) already provides an appropriate requirement: Paragraph (e) states that "Flares used to comply with provisions of this Subpart shall be operated at all times <u>when emissions may be vented to them</u>" and (f)(2) states "The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame." With the simple amendments to §60.5413(a) and §60.5413a(a) and §60.5417(d)(1) and §60.5417a(d)(1) shown below, EPA can allow the use of auto-ignition devices while also ensuring compliance.

Specific recommendations for these amendments are provided in Section 12.5.6

12.5.4 Testing Should Not Be Required To Demonstrate Compliance With §60.18(f)(4)

Paragraph 60.18(f)(4) requires that the volumetric flow rate be "*determined by Reference Methods 2, 2A, 2C, or 2D as appropriate*". As a result, a test will be required for every flare used to comply with Subparts OOOO and OOOOa. As discussed in section 11.1, the measurement of flow is impractical and potentially impossible at oil and natural gas production sites. In addition, even if these technical challenges were ignored, EPA's estimate of impacts did not include significant costs that would be incurred by the industry.

While not specifically referenced in this paragraph, the provisions in §60.8(c) require that performance tests be conducted on conditions that reflect "*representative performance of the affected facility*." During representative conditions, the exit velocities of the flare at oil and natural gas sites will never approach 400 feet per second. This can be easily demonstrated through the use of engineering calculations rather than testing or direct measurements. Specific changes must be made to §60.5413(a) and §60.5413a(a) to correct this situation. The recommendations for these amendments are provided in Section 12.5.6

The technical challenges related to volumetric flow rate are not unique to storage vessels in the production segment. At many gas processing plants, pressure release devices are often routed to flares along with the emissions from other equipment. While there are typically no emissions from these pressure release devices, they can develop leaks. Under Subparts OOOO and OOOOa, these pressure relief devices are subject to §60.482-4a(a) of NSPS Subpart VVa. Since these pressure release devices are routed to a "closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device", they are exempt from the leak detection and repair (LDAR) requirements in §60.482-4a(a) and (b), but are subject to the closed vent system and control device requirements of §60.482-10a. Paragraph §60.482-10a(d) requires flares to comply with §60.18. The leaks that would occur from these pressure release devices would be very low, meaning that the

[9] http://www3.epa.gov/gasstar/documents/installelectronicflareignitiondevices.pdf

difficulties in measuring the flow to these flares results in costly test programs that are entirely unnecessary given the extremely low flow rates. Therefore, API also recommends that the volumetric flow rate for these flares also be allowed to be determined using engineering calculations. API suggests that paragraphs be added to §60.5401 and §60.5401a to address this technical infeasibility situation. These recommendations for these amendments are provided in Section 12.5.6

12.5.5 Sonic And Other Flares Operated During Maintenance, Startup, Shutdown, And Malfunction Situations Should Not Be Required To Comply With The Exit Velocity Requirements In §60.18(c)(4)

In EPA's September 18, 2015 Federal Register Notice (80 FR 56646), EPA specifically requested comment on the use of pressure-assisted flares in the oil and natural gas industry.

As EPA notes, pressure-assisted, or sonic, flares are designed to exceed §60.18's maximum exit velocity of 400 feet per second. As a result, they do not meet §60.18. Some facilities with potential large volume flows may utilize sonic flares, such as those included at onshore natural gas processing facilities, to control emissions in times of emergency, upsets, or maintenance. Sonic flares offer advantages over traditional low-pressure flares in some applications. For example, some designs allow smokeless operation over the entire operating range without any assist medium. This is a clear benefit for remote areas. Additionally, with no assist medium, energy usage and its related emissions are minimized and there remains no potential for steam/air over-assist. Some designs also offer less low frequency noise and less flame visibility in low profile designs. Sonic flares operate with destruction efficiencies that are at least as equivalent to, and generally greater, than low pressure flares.

Pressure-assisted (sonic) flares are not designed for continuous use, but instead operate in emergency, upset or maintenance situations where high volumes and pressures are sent to the flare. In some scenarios, pressure relief valves subject to LDAR monitoring are routed to sonic flares for the purpose of emergencies or upsets. Maintenance events are also routed to these flares in some cases.

However, a conflict with the velocity limits in §60.18(c)(3) is not limited to the case of pressure-assisted flares. Velocity limits for commonly used low-pressure flares (ground or elevated steam-assisted, air-assisted or unassisted flares) are achievable under representative day-to-day conditions. However, velocity limits for even low-pressure flares can be exceeded under conditions that approach the hydraulic capacity of flares. General application of §60.18(b) to a Subpart without the inclusion of §60.11 or an alternative exemption for periods of emergency, upset or maintenance is problematic.

Flares designed under §60.18(b) may exceed velocity limits during periods of emergency, upset or maintenance. In order to remain in compliance with the velocity limits, flare operators would need to install additional flare capacity for SSM events either by replacing an existing flare or adding additional flares. Therefore, the exemption from the §60.18 maximum velocity requirements should not be limited to pressure-assisted flares, but rather to all flares during periods of emergency, upset, or maintenance. As discussed in section 12.5.7 below, there is substantial evidence that indicates that the performance of flares will be maintained at these higher velocities.

Therefore, in order to allow the use of sonic flares and traditional flares designed under §60.18(b) for the oil and natural gas industry, EPA should exempt flares from the maximum velocity requirements in §60.18(c)(4).

Revisions are needed to §60.5413(a) and §60.5413a(a), and to §60.5401 and §60.5401a to allow the use of flares in these situations. The recommendations for these amendments are provided in Section 12.5.6.

In addition, changes are needed to Table 3 of both Subparts OOOO and OOOOa. The recommendations for these amendments are provided in Section 12.5.6

12.5.6 Recommended Rule Changes To Address Issues With Flare Requirements

The following are the recommended rule changes related to the issues discussed above that are related to the requirement that flares used for Subparts OOOO and OOOOa comply with the requirements of §60.18.

Subpart OOOO

§60.5401
(h) For a flare that is subject to §60.18 via §60.482-10a(d), the volumetric flowrate used to calculate the actual exit velocity in §60.18(f)(4) may be determined using engineering calculations based on conditions that reflect representative performance of the process unit. In addition, the velocity limits in §60.18(c)(3) do not apply during periods of emergency, upset, or maintenance.

§60.5412
(d) Each control device used to meet the emission reduction standard in §60.5395(d) for your storage vessel affected facility must be installed according to paragraphs (d)(1) through (3) of this section, as applicable, and (d)(4). As an alternative to paragraph (d)(1) of this section, you may install a control device model tested under §60.5413(d), which meets the criteria in §60.5413(d)(11) and §60.5413(e).
* * * * *
(3) You must design and operate a flare in accordance with the requirements of §60.5413.
(~~3~~4) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes from working or flash losses are vented from the storage vessel affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

§60.5413
This section applies to the performance testing of control devices used to demonstrate compliance with the emissions standards for your centrifugal compressor and storage vessel affected facility. You must demonstrate that a control device achieves the performance requirements of §60.5412(a) using the performance test methods and procedures specified in this section. For condensers, you may use a design analysis as specified in paragraph (c) of this section in lieu of complying with paragraph (b) of this section. In addition, this section contains the requirements for enclosed combustion device performance tests conducted by the manufacturer applicable to both storage vessel and centrifugal compressor affected facilities.
(a) *Performance test exemptions.* You are exempt from the requirements to conduct performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through (7) of this section.
(1) A flare that is designed and operated in accordance with §60.18(b), with the exceptions noted in paragraphs (a)(1)(i) through (iii) of this section. You must conduct the compliance determination using Method 22 at 40 CFR part 60, appendix A-7, to determine visible emissions.
(i) A flare that is equipped with an electronic ignition system will satisfy the requirements in §60.18(c)(2) and (e),
(ii) The volumetric flowrate used to calculate the actual exit velocity in §60.18(f)(4) may be determined using engineering calculations based on conditions that reflect representative performance of the centrifugal compressor, pneumatic pump, or storage vessel affected facility, and

(iii) During periods of emergency, upset, or maintenance, the velocity limits in §60.18(c)(3) do not apply.

§60.5417(d)(1)
(iii) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the ~~continuous ignition of the pilot flame~~ presence of a flame as required in §60.5412(d)(4).

Table 3 to Subpart OOOO of Part 60 – Applicability of General Provisions to Subpart OOOO

General provisions citation	Subject of citation	Applies to subpart?	Explanation
§ 60.18	General control device and work practice requirements	Yes	Except that (1) A flare that is equipped with an electronic ignition system will satisfy the requirements in §60.18(c)(2). (2) The volumetric flowrate used to calculate the actual exit velocity in §60.18(f)(4) may be determined using engineering calculations based on conditions that reflect representative performance of the centrifugal compressor, pneumatic pump, or storage vessel affected facility. (3) During periods of emergency, upset, or maintenance, the velocity limits in §60.18(c)(3) do not apply.

Subpart OOOOa

§60.5401a
(h) For a flare that is subject to §60.18 via §60.482-10a(d), the volumetric flowrate used to calculate the actual exit velocity in §60.18(f)(4) may be determined using engineering calculations based on conditions that reflect representative performance of the process unit. In addition, the velocity limits in §60.18(c)(3) do not apply during periods of emergency, upset, or maintenance.

§60.5412a
(d) Each control device used to meet the emission reduction standard in §60.5395a(a) for your storage vessel affected facility must be installed according to paragraphs (d)(1) through (3) of this section, as applicable, and (d)(4). As an alternative to paragraph (d)(1) of this section, you may install a control device model tested under §60.5413a(d), which meets the criteria in §60.5413a(d)(11) and §60.5413a(e).
* * * * *
(3) You must design and operate a flare in accordance with the requirements of §60.5413a.
(~~3~~4) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes from working or flash losses are vented from the storage vessel affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

§60.5413a(a)
(1) A flare that is designed and operated in accordance with §60.18(b), with the exceptions noted in paragraphs (a)(1)(i) through (iii) of this section. You must conduct

the compliance determination using Method 22 of appendix A-7 of this part to determine visible emissions.
(i) A flare that is equipped with an electronic ignition system will satisfy the requirements in §60.18(c)(2) and (e),
(ii) The volumetric flowrate used to calculate the actual exit velocity in §60.18(f)(4) may be determined using engineering calculations based on conditions that reflect representative performance of the centrifugal compressor, pneumatic pump, or storage vessel affected facility, and
(iii) During periods of emergency, upset, or maintenance, the velocity limits in §60.18(c)(3) do not apply.

§60.5417a(d)(1)
(iii) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the ~~continuous ignition of the pilot flame~~ presence of a flame as required in §60.5412(d)(4).

Table 3 to Subpart OOOOa of Part 60 – Applicability of General Provisions to Subpart OOOO

General provisions citation	Subject of citation	Applies to subpart?	Explanation
§ 60.18	General control device and work practice requirements	Yes	Except that (1) A flare that is equipped with an electronic ignition system will satisfy the requirements in §60.18(c)(2). (2) The volumetric flowrate used to calculate the actual exit velocity in §60.18(f)(4) may be determined using engineering calculations based on conditions that reflect representative performance of the centrifugal compressor, pneumatic pump, or storage vessel affected facility. (3) During periods of emergency, upset, or maintenance, the velocity limits in §60.18(c)(3) do not apply.

12.5.7 Velocity Limits In §60.18(C)(3) Are Unnecessary To Ensure High Destruction Efficiency In Flares

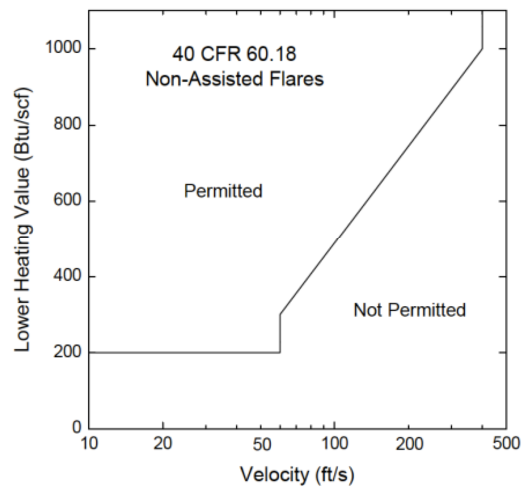
There is substantial evidence that flares operating with higher exit velocities are effective in reducing emissions. Following is a discussion of this evidence. [10]

Origins of Existing Flare Velocity Limits

The velocity limits in 40 CFR 60.18 were originally promulgated on January 21, 1986 and are graphically depicted below. The figure shows flame exit velocities in feet-per-second (fps) along the x-axis and lower heating value of the waste gas in Btu/scf along the y-axis. A minimum heat content is required of 200 Btu/scf for unassisted flares or 300 Btu/scf for assisted flares up to 60 fps, where the required heat content increases as a function of exit velocity until a maximum allowable velocity of 400 fps is reached.

[10] Adapted from "A Review of Flare Velocity Limits in 40 CFR 60.18 and 63.11." Prepared for American Petroleum Institute October 26, 2014 by Scott Evans.

Figure 12-1 Current EPA Flare Velocity Limits



This relationship was developed following a series of EPA sponsored tests conducted in the 1980's that examined how various flare operating parameters, including velocity, affect flare performance. The tests with relevance to the current velocity requirements are the 1983 McDaniel[11] test and the 1984 Pohl[12] test. The focus of the 1985 Pohl[13] and 1986 Pohl[14] studies was not on high velocity, but any test runs from these studies where the exit velocity of the flare was greater than 60 feet per second (fps) have been included in this analysis.

The 1986 limits appear to originate with only four data points from these tests – the average value at the upper limits of each study. The 60 fps, 300 Btu/scf limit for steam-assisted flares was set based on a single data point -- McDaniel 1983[11] test 57. The 200 Btu/scf limit for unassisted flares was also set based on a single data point – McDaniel test 59. These tests were performed on an 8.6-inch steam-assisted flare fueled with a propylene/nitrogen mix. The data are shown in Figure 12-3. The data are binned by heat content, where red dots indicate test runs whose combustion zone net heating value (NHVVG) is less than 270 Btu/scf, green dots indicate test runs with NHVVG between 270 and 500 Btu/scf, and blue indicate test runs with NHVVG greater than 500 Btu/scf.

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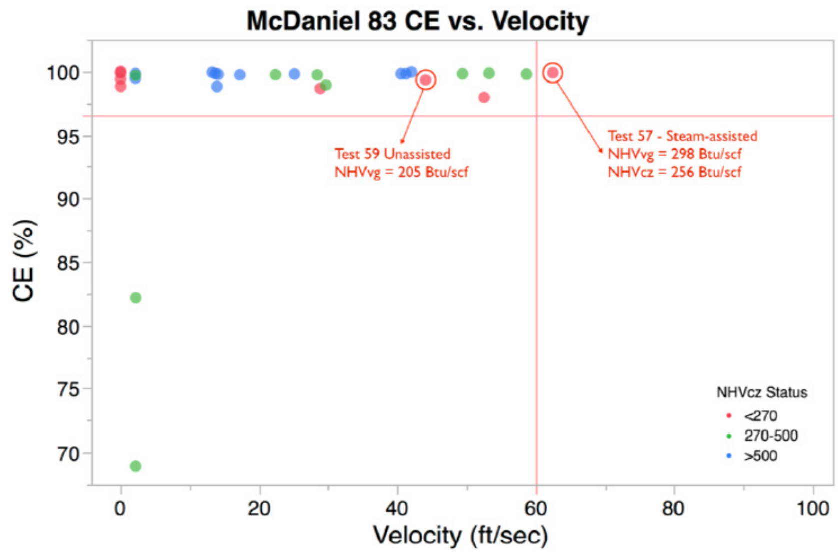
[11] McDaniel, M.; "Flare Efficiency Study," EPA-600/2-83-052, July 1983
[12] Pohl, J., et. Al.; "Evaluation of the Efficiency of Industrial Flares: Test Results," EPA-600/2-84-095
[13] Pohl, J, and Soelberg, N.; "Evaluation of the Efficiency of Industrial Flares: Flare Head Design and Gas Compostion," EPA-600/2-85-106, September 1986
[14] Pohl, J, and Soelberg, N.; "Evaluation of the Efficiency of Industrial Flares: H2S Gas Mixtures and Pilot Assisted Flares," EPA-600/2-86-080; September 1986

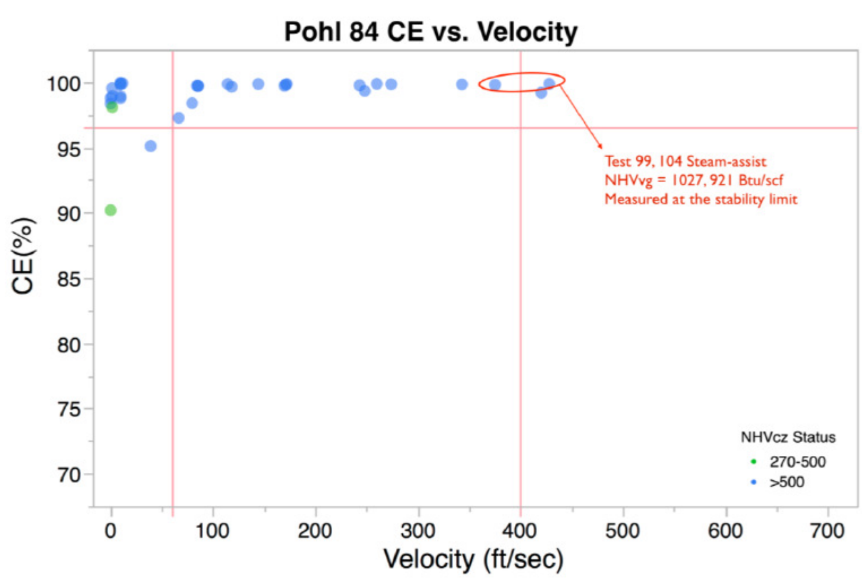
Figure 12-2 A Comparison of Combustion Efficiency vs Velocity for McDaniel 1983



McDaniel did not collect data at velocities higher than 60 fps. At the 60 fps upper limit of the data, combustion efficiency remained very high and with no evidence of a trend toward lower combustion efficiency. These data were used to establish the 60 fps velocity limit although there is no evidence that operating at higher velocities results in degraded combustion efficiency.

The 400 fps, 1,000 Btu/scf limit appears to be set based on two data points from flame stability test runs 99 and 104 from Pohl 1984.[12] That study was performed on a 3-inch steam assisted flare fueled with a propane/nitrogen mix. These data are shown in Figure 12-3. The data are binned by heat content, where green dots indicate test runs with combustion zone net heating value (NHVCZ) between 270 and 500 Btu/scf and blue indicate test runs with NHVCZ greater than 500 Btu/scf.

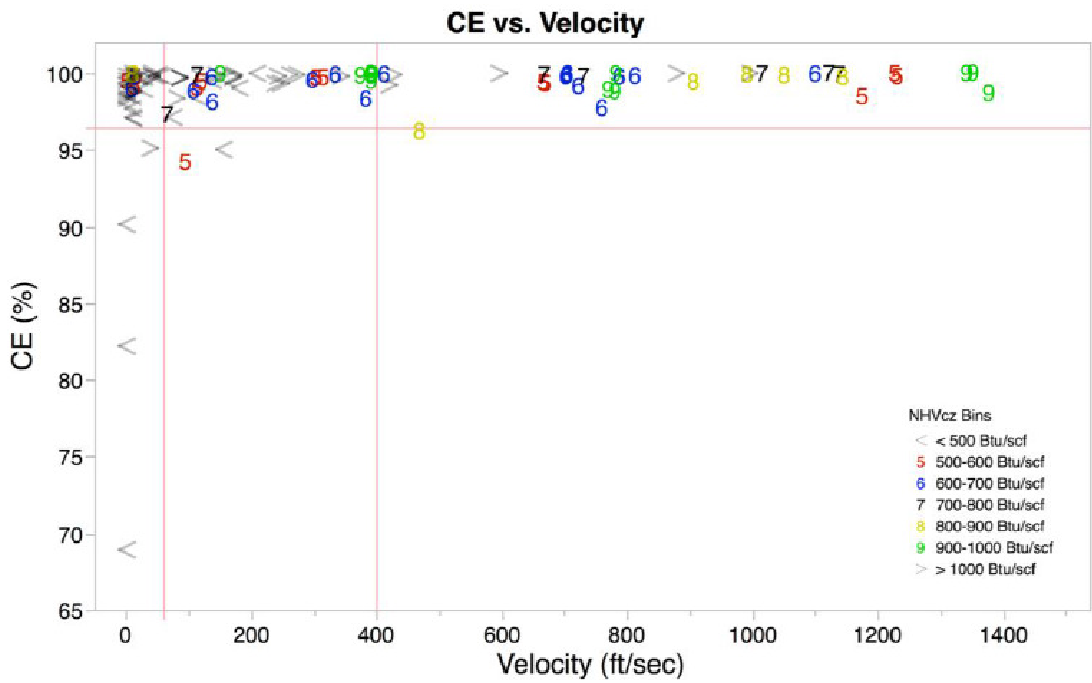
Figure 12-3 A Comparison of Combustion Efficiency vs Velocity for Pohl 1984



Similarly to the data used to establish the 60 fps limit, data collected in this study were not collected at velocities higher than the upper limit of 400 fps. As in McDaniel 83, Pohl 84 showed no evidence of a trend towards lower combustion efficiency at the upper velocity limit measured. These data were used to establish the 400 fps limit although there is no evidence that operating at higher velocities results in degraded combustion efficiency.

High Velocity Flare Test DataFigure 12-4 shows all data from publically available high velocity flare tests as of October 2014. Some low velocity data are also included to the extent that they were measured during a test series including high velocity data. Data includes the 1980's flare studies referenced above as well as more recent studies (Marathon Garyville[15] and Dow[16]). This data is similarly displayed based upon combustion efficiency (CE) as a function of exit velocity in fps. The data is binned by NHVCZ in groups of 500 Btu/scf. Only data with NHVCZ > 270 are included.

Figure 12-4 A Comparison of Combustion Efficiency vs Velocity for All Publically Available High Velocity Flare Tests binned by NHVCZ Range



Almost all of the low velocity data that also have low CE have NHVCZ values less than 500 Btu/scf. Additionally, virtually all of the test runs with velocity greater than the current limit of 400 fps, were conducted at NHVCZ values less than the current 1,000 Btu/scf limit. This graph clearly shows that high combustion efficiency above the current limits is not only possible, but that it is assured based upon available test data.

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[15] Clean Air Engineering, "Performance Test of Steam-Assisted and Pressure-Assisted Ground Flare Burners with Passive FTIR – Garyville," March 21, 2013

[16] Varner, V., Kodesh, Z.; "Emission Testing of Pressure Assisted Flare Burners," Presented at the American Flame Research Committee 2014 Industrial Combustion Symposium, September 2014

Flame Stability

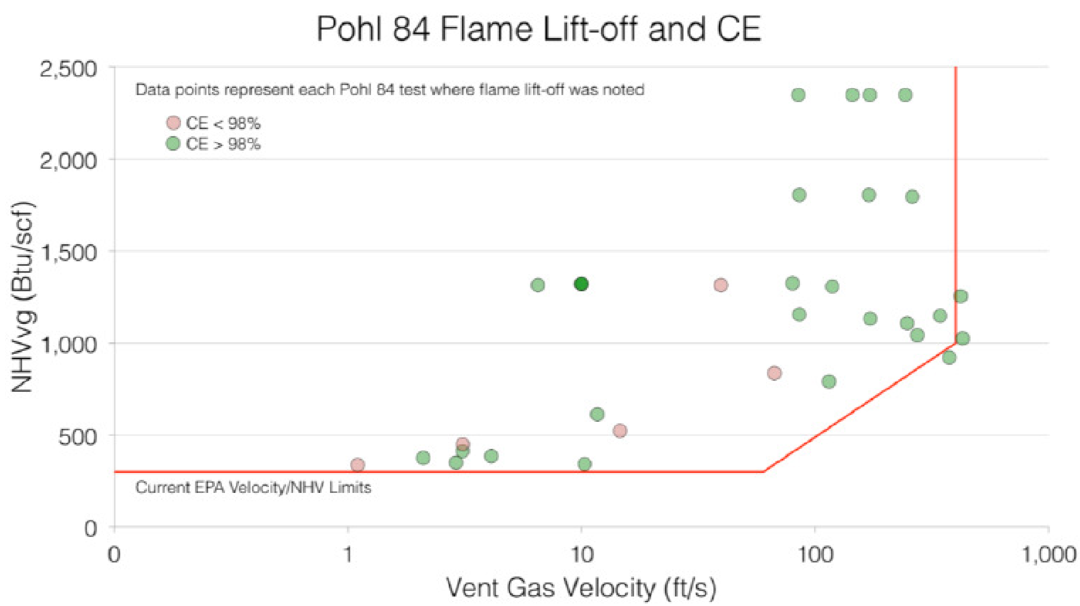
The claim is often made that the reason velocity limits are necessary is to ensure "flame stability." However, flame stability has been defined differently in different studies. McDaniel did not address flame stability. Pohl defines flame stability as:

"The term *flame stability* simply means that a flame is maintained; flame instability occurs when the jet velocity exceeds the flame velocity and the flame goes out." [Pohl 84, p2-3]

Others[17] have defined flame stability in terms of "lift-off", a conditions that occurs when the base of the flame detaches from the flare tip.

While there is no doubt that Pohl's definition results in unacceptable flare performance, there is little evidence that flame lift-off has any correlation either positive or negative to combustion efficiency. Figure 12-5 shows every data point from Pohl 84 where flame lift-off was noted in the report.

Figure 12-5 A Comparison of Flame Lift-Off and Combustion Efficiency from Pohl 84



Twenty-seven of the 32 lifted flames showed high combustion efficiency. None of the remaining five points had measured combustion efficiency below 91%. Figure 12-5 clearly shows that flame lift-off does not affect combustion efficiency over a wide range of velocities and net heating values.

Concern over flame lift-off affecting combustion efficiency is not supported by the data. The only definition of flame stability with relevance to velocity limits is Pohl's definition that a high velocity flame is stable until it goes out.

There is also no evidence of a gradual decline of combustion efficiency when approaching the point where the flame is extinguished or the "snuff point." Both the Pohl 84 data and the Marathon Garyville

[17] Shore, D., "Improving Flare Design: A Transition From Art-Form to Engineering Science," Presented at AFRC-JFRC October, 2007.

data were collected as near as possible to the snuff point while still maintaining a flame. No evidence of degraded combustion efficiency was noted.

Conclusion

Current flare velocity limits restrict flare operation above 60 fps and prohibit operation entirely above 400 fps. This paper reviewed data from the data sets used to establish those federal regulatory velocity limits as well as recent high velocity flare test results.

All of the data collected, including the data used previously to set current limits as well as recently collected data, show that high velocity flaring results in high flare combustion efficiency (>96.5%). Previous limits were based solely on lack of data at higher flare exit velocities. There is no indication either in the 1980's studies or the more recent flare studies that high velocity flaring contributes to poor combustion efficiency.

The data on high velocity flaring is consistent with combustion theory, which shows that high velocity flames result in better air entrainment and mixing and so result in higher combustion efficiency. Limits on high velocity flaring are unnecessary and, in fact, counter-productive.

12.6 Control Devices in Compliance with NESHAP Subpart HH Should be Exempt

There is a high likelihood that a site with equipment subject to MACT HH (40 CFR 63, Subpart HH) will also have affected facilities subject to Subpart OOOOa. In these situations, it is possible a control device will be used to comply with both MACT HH and Subpart OOOOa. This could result in the same control device being subject to requirements under both Subparts that are not entirely aligned. In order to avoid these needless requirements, API requests that §60.5412a clearly state that control devices that are subject to 40 CFR 63, Subpart HH are exempt from the requirements in Subpart OOOOa. Following is recommended regulatory language to clarify this exemption.

§60.5412a

You must meet the applicable requirements of this section for each control device used to comply with the emission standards for your centrifugal compressor affected facility, pneumatic pump affected facility, or storage vessel affected facility. Control devices in compliance with the requirements in §63.771 of 40 CFR 63, Subpart HH are exempt from the requirements in this Subpart.

12.7 While EPA Has Been Testing Various Manufacturer Devices, the Process has been Slow

NSPS Subpart OOOO (40 CFR 60, Subpart OOOO) and MACT HH and HHH (40 CFR 63, Subparts HH and HHH) allow for the use of combustion devices that are tested by the manufacturer which eliminates the need for source testing at the site. EPA maintains a list of approved Combustion Control Devices[18] on their website. EPA has also stated that the current "approved list" will be adopted for OOOOa. API requests confirmation of this in the response to comments to reflect EPA's intent.

However, there are several issues with the approval process. First, more than half of the devices listed on the website are characterized as "under review", and they have maintained this status for a long period of time (one or more years). According to one manufacturer, the approval process should be less than a month. The NSPS will result in the need for many more combustion devices to control existing sources, which increases the need to step up the approval process. Closer inspection revealed that incomplete test reports may be a possible cause for achieving "under review" status, and therefore it may not be a fault of

[18] http://www3.epa.gov/airquality/oilandgas/pdfs/mantesteddevices.pdf

EPA's process. However, EPA needs to investigate the cause for these long delays in this approval process and correct them.

Second, manufacturers report that relief from propene testing would decrease the testing costs considerably. It makes no sense to require propene testing for combustion devices that will be used at oil and natural gas production facilities as there are insignificant amounts of double bond hydrocarbon compounds in natural gas. API requests that §60.5413a(d)(2) be modified as follows to allow the use of propane to expedite the approval process.

> (2) Performance testing must consist of three 1-hour (or longer) test runs for each of the four firing rate settings specified in paragraphs (d)(2)(i) through (iv) of this section, making a total of 12 test runs per test. ~~Propene (propylene)~~ Propane gas must be used for the testing fuel. All fuel analyses must be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

13.0 EPA MUST ELIMINATE THE CONFUSION AND CONFLICT ASSOCIATED WITH "CONTROL DEVICE" AND "ROUTED TO A PROCESS"

It clear from the proposed control requirements for centrifugal compressors (§60.5380a(a)(2)), pneumatic pumps (§60.5393a(b)(4), and storage vessels (§60.5395a(b)(1)) that "route to a process" was intended as an alternative to a control device. For example:

§60.5380a(a)(2): If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of §60.5411a(b). The cover must be connected through a closed vent system that meets the requirements of §60.5411a(a) and the closed vent system must be routed to a control device that meets the conditions specified in §60.5412a(a), (b) and (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

However, the definitions and provisions related to "control device" and "routed to a process" are inconsistent and confusing, and in some instances, conflicting. This is particularly the case with regard to boilers and process heaters. The following sections highlight these issues and suggest a solution that will eliminate the confusion and conflicts without any reduction in the effectiveness of the rule.

13.1 Definition Of "Routed To A Process" Should Be Clarified

Section 60.5430 of proposed §60.5430a of Subpart OOOOa includes the following definition:

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.

The use of "routed to a process" is clear as used in §60.5365a(e)(3) in connection to a VRU, as these emissions are recycled and incorporated into a product.

This definition also unmistakably applies to situations where the emissions are combusted in a boiler or process heater. There are three different ways in which hydrocarbon vapors can be fed into a boiler or process heater for destruction – 1) vapors routed to the flame zone, 2) vapors routed to the fuel system as a primary fuel, and 3) vapors routed to the combustion air supply as a secondary fuel. For all three of these methods of introducing hydrocarbon emissions into a boiler or process heater the emissions are clearly "consumed in the same manner as the material that fulfills the same function in the process". Further, the emissions are "transformed by chemical reaction into materials that are not regulated materials". However, Subparts OOOO and OOOOa are not as clear how this definition applies for boilers and process heaters. EPA must clarify this linkage between "routed to a process" and boilers and process heaters throughout the final rule.

Despite the fact that EPA defined routed to a process/route to a process in a manner that would include all situations when emissions are routed to a boiler or process heater, there are instances throughout both Subpart OOOO and OOOOa where EPA appears to consider boilers and process heaters as control devices. For example, in §60.5412(a)(1) and §60.5412a(a)(1), EPA includes boilers and process heaters in a parenthetical describing a combustion device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater). Similarly, this same parenthetical description of enclosed combustion device in in §60.5412(d)(1) and §60.5412a(d)(1). Further, in the list of "control devices" exempted from performance testing in §60.5413(a) and §60.5412a(a), there are several specific boiler and process heater examples that are exempted.

One of these exemptions, specifically §60.5413(a)(3) and §60.5412a(a)(3), exempts boilers or process heater "into which the vent stream is introduced with the primary fuel or is used as the primary fuel." These seems to indicate that EPA draws a distinction between the three situations described above where emissions are routed to a boiler or process heater (even though they are all three clearly covered by the definition of "routed to a process").

The recommended changes discussed below resolve this conflict.

13.1.1 NSPS SUBPARTS VV AND VVA INCLUDE THE CONCEPT OF "FUEL GAS"

In the rulemakings for NSPS Subparts VV and VVa, EPA has addressed this same basic situation in a clear and reasonable manner. For example, §60.482-4a(c) states that:

"Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in §60.482-10a is exempted from the requirements of paragraphs (a) and (b) of this section."

Further, Subpart VVa includes the following related definitions.

Fuel gas means gases that are combusted to derive useful work or heat.

Fuel gas system means the offsite and onsite piping and flow and pressure control system that gathers gaseous stream(s) generated by onsite operations, may blend them with other sources of gas, and transports the gaseous stream for use as fuel gas in combustion devices or in-process combustion equipment, such as furnaces and gas turbines, either singly or in combination.

API believes that this precedent can be utilized to improve the clarity in Subparts OOOO and OOOOa. This recommendation is provided below.

13.1.2 Recommended Change To Definition Of "Routed To A Process Or Route To A Process"

API recommends that the following changes be made to the definition of routed to a process or route to a process" in both Subparts OOOO and OOOOa.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered. Emissions used as fuel gas in a boiler, process heater, or other combustion device are considered to be routed to a process.

API further recommends that the following definition of fuel gas be added.

Fuel gas means gases that are combusted to derive useful work or heat.

13.2 Definitions of "Control Device", "Combustion Device", and "Combustion Control Device"

The confusion discussed above between related to boilers and process heaters and routed to a process is acerbated by the fact that neither Subpart OOOO or Subpart OOOOa define control device. In addition to this situation that needs to be corrected, the Subpart OOOOa proposal for pneumatic pumps make defining "control device" critical. This is discussed later in Section 24.0.

As discussed in section 13.1.2, the definition of "routed to a process" clearly includes routing emissions to a boiler or process heater to be consumed, yet both Subparts OOOO and OOOOa discuss boilers and process heaters as control devices in other places.

In addition, the situation is further confused as EPA uses the terms "combustion device", "combustion control device", and "enclosed combustion control device" in an arbitrary manner that further confuses the situation. None of these terms are defined in proposed Subpart OOOOa.

In conjunction with the recommended definitions in section 13.1.2, **API offers the following definitions to be added to §60.5430a of OOOOa.**

> *Control device* means any equipment used for recovering or oxidizing volatile organic compound (VOC) or methane emissions. Such equipment includes, but is not limited to, absorbers, carbon adsorbers, condensers, and combustion devices. Recovery devices that recycle the emissions back to the process, and combustion devices that use the emissions as fuel gas, are not considered control devices under this Subpart.
>
> *Combustion control device means* a thermal vapor incinerator, catalytic vapor incinerator, flare, or other combustion device that do not burn emissions as a fuel gas.
>
> *Enclosed combustion control device* means a combustion control device with an enclosure such that the flame is not an open flame.

This definition of control device, along with the definition of "routed to a process or route to a process" recognizes that routing to a process is not emissions control but rather a beneficial use or reuse of exhaust gases and vapors. Thus, routing pneumatic pump exhaust or compressor blowdown gas to be used as a fuel gas would not make heaters or boilers using these streams part of a control device.

In addition, the following changes are needed throughout Subpart OOOOa to rectify the inconsistent usage of these terms throughout. These changes also address the changes related to boilers and process heaters and "routed to a process."

> **§60.5412a**
> (a) Each control device used to meet the emission reduction standard in §60.5380a(a)(1) for your centrifugal compressor affected facility or §60.5393a(b)(1) for your pneumatic pump must be installed according to paragraphs (a)(1) through (3) of this section. As an alternative, you may install a combustion control device model tested under §60.5413a(d), which meets the criteria in §60.5413a(d)(11) and §60.5413a(e).
> (1) Each combustion control device ~~(e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater)~~ , except for a flare, must be designed and operated in accordance with one of the performance requirements specified in paragraphs (a)(1)(i) through (~~iv~~iii) of this section.
> * * * * *

~~(iv) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.~~

* * * * *

(d) Each control device used to meet the emission reduction standard in section §60.5395a(a) for a storage vessel must be installed according to paragraphs (d)(1) through (4) of this section, as applicable. As an alternative to paragraph (d)(1) of this section, you may install a combustion control device model tested under section §60.5413a(d), which meets the criteria in section §60.5413a(d)(11) and §60.5413a(e).

(1) For each enclosed combustion control device ~~(e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater)~~ you must meet the requirements in paragraphs (d)(1)(i) through (iv) of this section.

* * * * *

(iv) Each combustion control device ~~(e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater)~~ must be designed and operated in accordance with one of the performance requirements specified in paragraphs (A) through (~~D~~C) of this section.

* * * * *

~~(D) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.~~

§60.5413a

(a) Performance test exemptions. You are exempt from the requirements to conduct performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through (~~7~~5) of this section.

~~(2) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.~~

~~(3) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel.~~

(~~4~~2) A boiler or process heater burning hazardous waste for which you have either been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 266, Subpart H; or you have certified compliance with the interim status requirements of 40 CFR part 266, Subpart H.

(~~5~~3) A hazardous waste incinerator for which you have been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 264, Subpart O; or you have certified compliance with the interim status requirements of 40 CFR part 265, Subpart O.

(~~6~~4) A performance test is waived in accordance with §60.8(b).

(~~7~~5) A combustion control device whose model can be demonstrated to meet the performance requirements of §60.5412a(a) or (d) through a performance test conducted by the manufacturer, as specified in paragraph (d) of this section.

* * * * *

(b)(3)(iv) Reserved ~~If the vent stream entering a boiler or process heater with a design capacity less than 44 megawatts is introduced with the combustion air or as a secondary fuel, you must determine the weight-percent reduction of total TOC (minus methane and ethane) across the device by comparing the TOC (minus methane and ethane) in all combusted vent streams and primary and secondary fuels with the TOC (minus methane and ethane) exiting the device, respectively~~.

§60.5417a
(b) Reserved ~~You are exempt from the monitoring requirements specified in paragraphs (c) through (g) of this section for the control devices listed in paragraphs (b)(1) and (2) of this section.~~
~~(1) A boiler or process heater in which all vent streams are introduced with the primary fuel or are used as the primary fuel.~~
~~(2) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.~~
* * * * *
(d)(1)(iv) Reserved ~~For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5°C, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.~~
* * * * *
(d)(1)(viii) (A) The continuous monitoring system must measure gas flow rate at the inlet to the combustion control device. The monitoring instrument must have an accuracy of ±2 percent or better. The flow rate at the inlet to the combustion control device must not exceed the maximum or be less than the minimum flow rate determined by the manufacturer.
(B) A monitoring device that continuously indicates the presence of the pilot flame while emissions are routed to the combustion control device.

Similar requirements exist in Subpart OOOO and Subpart HH that should also be modified because of their conflict with the "route to a process" provisions.

14.0 THE PROPOSED BY-PASS DEVICE REQUIREMENTS ARE NOT REASONABLE AND WERE NOT JUSTIFIED BY EPA

EPA has added requirement to install a flow indicator and audible alarm and initiate notification via remote alarm to the nearest field office on the bypass device that could divert the stream away from the control device or process to the atmosphere. There are numerous issues with this proposal:

1. It appears to create retroactively revised requirements for existing sources under Subpart OOOO, which should not be done.
2. The proposal in Subparts OOOO and OOOOa is inconsistent.
3. EPA did not include the cost of the alarm and notification system in the cost analysis for Subparts OOOO or OOOOa.
4. Requiring notification presumes that automation with remote transmission capabilities is already present on site which may not be the case. If existing automation and remote transmission capabilities don't exist it would be unreasonable to require installation of these for purposes of monitoring a bypass device.
5. The verification processes are different for secured and non-secured devices.

These issues are discussed below in sections 14.1 through14.4. The by-pass requirements should be the same for non-secured and secured devices, only indicate an alarm onsite, and the requirements should not retroactively revise Subpart OOOO. Table 14-1 illustrates the existing rule language and points out inconsistencies and Table 14-2 provides recommended rule changes.

14.1 Retroactive Equipment Requirements

EPA appears to have retroactively changed the requirements under §60.5411(a)(3)(i)(A), §60.5411(c)(3)(i)(A), and §60.5416(c)(3)(i) to require that an alarm must be transmitted to the nearest field office since these rules apply to sources installed between August 23, 2011 and September 18, 2015. Previously, for compressors, there must only be an alarm with no indication of the location and for storage vessels there was an option for an alarm on site or remote alarm. Subpart OOOO currently reads:

§60.5411(a)(3)(i)(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that is **capable of taking periodic readings as specified in §60.5416(a)(4) and sounds an alarm** when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. **[Emphasis Added]**

§60.5411(c)(3)(i)(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere **that sounds an alarm, <u>or</u>, initiates notification via remote alarm to the nearest field office,** when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. **[Emphasis Added]**

EPA has no authority under § 111 to impose retroactive requirements. Therefore, EPA must make it clear in the final rule that these new requirements apply only prospectively to newly affected sources. In any event, the additional cost of having to add the equipment, do the programming, and maintenance of a system not already in place to send a notification to the nearest field office was not included in the cost analysis as discussed further in Section 14.3. Please Table 14-2 see for proposed changes to the rule.

14.2 The Requirements Are Inconsistent for Bypass Devices for Subparts OOOO and OOOOa

The proposed requirements are inconsistent between Subpart OOOO and Subpart OOOOa and between the different affected sources. These inconsistencies lead to problems implementing the requirements. A facility may have an affected storage vessel and an affected pump with multiple alarm requirements. If these requirements remain in Subpart OOOO, the requirement should be consistent with Subpart OOOOa to avoid confusion. Furthermore, the requirement should be consistent between the affected sources (i.e.,storage vessels, pumps, and compressors).

Please see Table 14-1 for further information on the inconsistencies between the two proposals and Table 14-2 for proposed changes to the rule.

14.3 EPA Did Not Consider the Cost of the Alarm and Notification Requirements

In the proposed non-secured by-pass device requirements, EPA did not consider the cost and technical feasibility of an audible alarm and notification via remote alarm at the nearest field office. A remote alarm at a field office does not add any additional environmental benefit where an onsite device meets the intent of the alarm requirements. There are several considerations for a field office to receive data from field locations including onsite equipment, programming, and installation and maintenance. Adding an alarm will require installation of new equipment requiring potentially a facility to be shut down and the equipment purged so that "hot work" can be performed to install the equipment which will result in additional emissions. Furthermore, a company would need a remote transmitter unit (RTU) installed or have an existing RTU with sufficient capacity to transmit a signal from the device to an operations center to notify the operations center. There are also cost associated with programming, installation, and maintenance of the alarm. Equipment and installation costs are several thousands of dollars for each data point, per site, routed into a system, even if existing monitoring equipment is located onsite. Ongoing support and maintenance of the monitored parameter is required to sustain operation. EPA did not include any of these costs in the justification for the proposed requirements.

14.4 The Verification Process between Secured and Non-secure is Inconsistent

For bypass devices secured with a car-seal or lock-and-key type configuration, the requirement is for visual verification that the device is secured. The requirements for non-secured devices should be similar and only require verification if the alarm - whether audio or visual - has been triggered. Since there is a flow indicator present, the amount vented would be known. Please see Table 14-2 for proposed changes to the rule.

Table 14-1 Comparison of Regulation Text as Written

Purpose			
Purple text is an OOOOa change from the previous OOOO version, Blue is inconsistencies between 1) **OOOO and OOOOa** and 2) **sources**.			
OOOO Centrifugal Compressors	**OOOOa Compressors, and Pumps**	**OOOO Storage Vessels**	**OOOOa Storage Vessels**
§60.5411(a)(3)(i)(A) – Centrifugal Compressors You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible alarm, and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to §60.5420(c)(8).	§60.5411a(a)(3)(i)(A) – Compressors, and Pumps You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and visible alarm, and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to §60.5420a(c)(8).	§60.5411a(c)(3)(i)(A) – Storage Vessels You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible alarm and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to §60.5420(c)(8).	§60.5411a(c)(3)(i)(A) – Storage Vessels You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger and audible and visible alarm, and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is sounded according to §60.5420a(c)(8).
§60.5416(a)(4)(i) – Compressors Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the	§60.5416a(a)(4)(i) – Compressors, and Pumps Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the steam	§60.5416(c)(3)(i) - Storage Vessels You must properly install, calibrate and maintain a flow indicator at the inlet to the bypass device that could divert the stream	§60.5416a(c)(3)(i) - Storage Vessels You must properly install, calibrate and maintain a flow indicator at the inlet to the

Purpose text is an OOOOa change from the previous OOOO version, Blue is inconsistencies between 1) **OOOO and OOOOa** and 2) **sources**.			
OOOO Centrifugal Compressors	**OOOOa Compressors, and Pumps**	**OOOO Storage Vessels**	**OOOOa Storage Vessels**
steam away from the control device to the atmosphere.	away from the control device to the atmosphere.	away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible alarm, and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to §60.5420(c)(8).	bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and visible alarm, and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is sounded according to §60.5420a(c)(8).

Table 14-2 Recommended Rule Text Revisions for Bypass Requirements – Redline

Consistent Text			
§60.5411(c)(3)(i)(A) – Centrifugal Compressors You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and/or visible alarm~~, and initiate notification via remote alarm to the nearest field office,~~ when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is discovered activated according to §60.5420(c)(8).	§60.5411a(a)(3)(i)(A) – Compressors, and Pumps You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and/or visible alarm~~, and initiate notification via remote alarm to the nearest field office,~~ when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is discovered ~~activated~~ according to §60.5420a(c)(8).	§60.5411(c)(3)(i)(A) – Storage Vessels You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and/or visible alarm, ~~and initiate notification via remote alarm to the nearest field office,~~ when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is discovered activated according to §60.5420(c)(8).	§60.5411a(c)(3)(i)(A) – Storage Vessels You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and/or visible alarm and ~~initiate notification via remote alarm to the nearest field office,~~ when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is discovered ~~sounded~~ according to §60.5420a(c)(8).

Consistent Text			
§60.5416(a)(4)(i) – Compressors ~~Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the steam away from the control device to the atmosphere.~~ You must properly install, calibrate and maintain a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and visible alarm, ~~and initiate notification via remote alarm to the nearest field office,~~ when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is discovered activated according to §60.5420(c)(8).	§60.5416a(a)(4)(i) – Compressors, and Pumps ~~Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the steam away from the control device to the atmosphere.~~ You must properly install, calibrate and maintain a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and visible alarm, ~~and initiate notification via remote alarm to the nearest field office,~~ when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is discovered activated according to §60.5420(c)(8).	§60.5416(c)(3)(i) - Storage Vessels You must properly install, calibrate and maintain a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and visible alarm, ~~and initiate notification via remote alarm to the nearest field office,~~ when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is discovered activated according to §60.5420(c)(8).	§60.5416a(c)(3)(i) - Storage Vessels . You must properly install, calibrate and maintain a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and visible alarm, ~~and initiate notification via remote alarm to the nearest field office,~~ when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is discovered ~~sounded~~ activated according to §60.5420a(c)(8).

15.0 THERE IS UNNECESSARY OVERLAP AND REDUNDANCY BETWEEN THE COVER AND CLOSED VENT SYSEM AND FUGITIVE EMISSION REQUIREMENTS

EPA proposes fugitive monitoring like requirements for closed vent systems, but also includes closed vent systems in the definition of Fugitive Emission Components. This results in CVS being subject to both closed vent system and fugitive emission component monitoring requirements in §60.5397a and §60.5416a. This creates a situation which is unnecessarily duplicative and redundant. Specifically, EPA has required both optical gas imaging monitoring for the tank cover and the closed vent systems under §60.5397a, as well the following under §60.5416a:

- Annual Method 21 (M21) monitoring and visual inspections for closed vent systems for centrifugal compressors and pneumatic pumps, and
- Monthly olfactory, visual, and auditory inspections for storage vessel covers and closed vent systems.

This could result in as many as three different leak detection programs at a single facility.

To avoid this conflict, API provides recommendations that will eliminate this overlap while still ensuring that emissions from leaks from closed vent system components are minimized. The problem and API's recommendations are discussed in detail in Sections 26.0.

16.0 THE PROPOSED EQUATION FOR CAPITAL EXPENDITURE IS NOT REPRESENTATIVE OF CURRENT ECONOMIC CONDITIONS.

16.1 The Proposed Equation Models Inflation Improperly, Potentially Accelerating Moving Sites From KKK To OOOO And Impacting Processing Plant Economics.

The original equation proposed by EPA in §60.5430a is the following; A = B * Y, where Y = 1 – 0.575*log(1982-X), X = the year and B = 4.5. This formula was modeled based on the inflation of the late 1970s and early 1980s. This inflation was much higher than that seen today. Simply inserting 2011 into this equation will unrepresentatively discount the value of B. API proposes that EPA use a Consumer Price Index (CPI) based equation to discount B (valued at 4.5% for our industry) as shown below:

Y = (CPI of date of construction or reconstruction/CPI of date of component price data)

The component price data must be adjusted for inflation if it is not current data.
Figure 16-1 and Figure 16-2 depict a comparison of the two equations showing the value of A, the red curve using the proposed equation Y = 1 – 0.575*log(2011-X), and the blue curve showing the equation above using 2012 price data. This demonstrates that the equation proposed by the EPA unrepresentatively overstates the effect of inflation in terms of discounting the value of B. The second graph (Figure 16-2) shows that using Y = 1 – 0.575*log(1982-X), and 1982 as the date of component price data, the value of Y predicts inflation adequately for the late 1970s and early 1980s.

The effect of the improper use of inflation is that gas plants that are built after 1982 that were not designed to comply with the more stringent OOOO regulations will be forced to comply with OOOO with as little as one valve added to the process unit. Large replacements of "equipment" (as defined in the regulation) may be needed to comply with this change, and permanent plant shutdowns may occur as a result because these replacements are uneconomic. This could result in increased flaring of wet gas and increased VOC emissions, or the shutting in of oil wells as a result.

In addition, EPA must ensure that the definition of expenditure is not retroactive to eliminate interpretation issues.

Figure 16-1 AAAGRP Discount from B = 4.5% Method Comparison (2011)

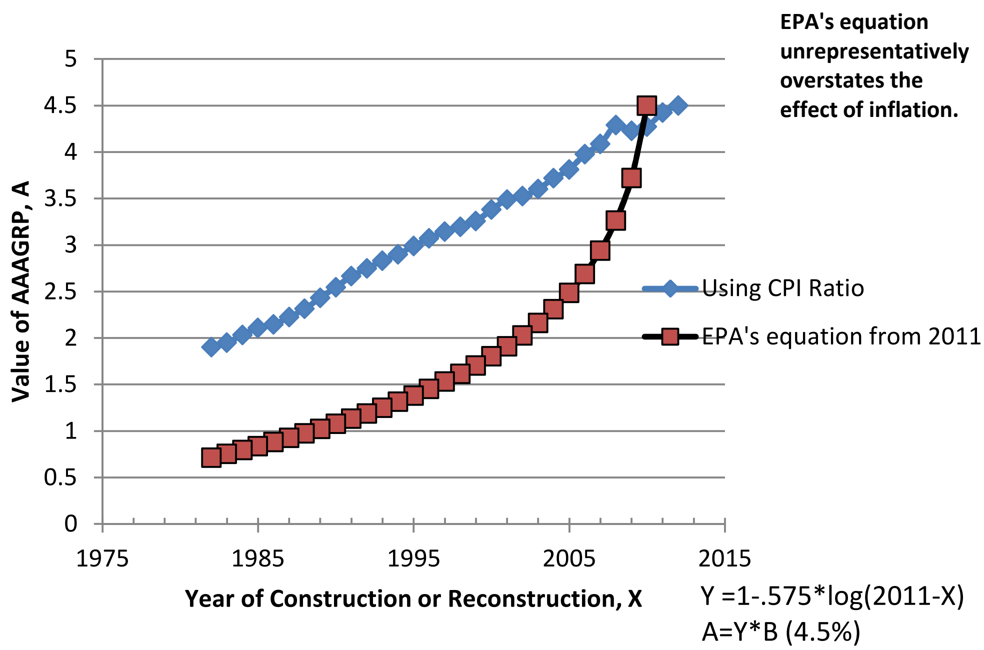
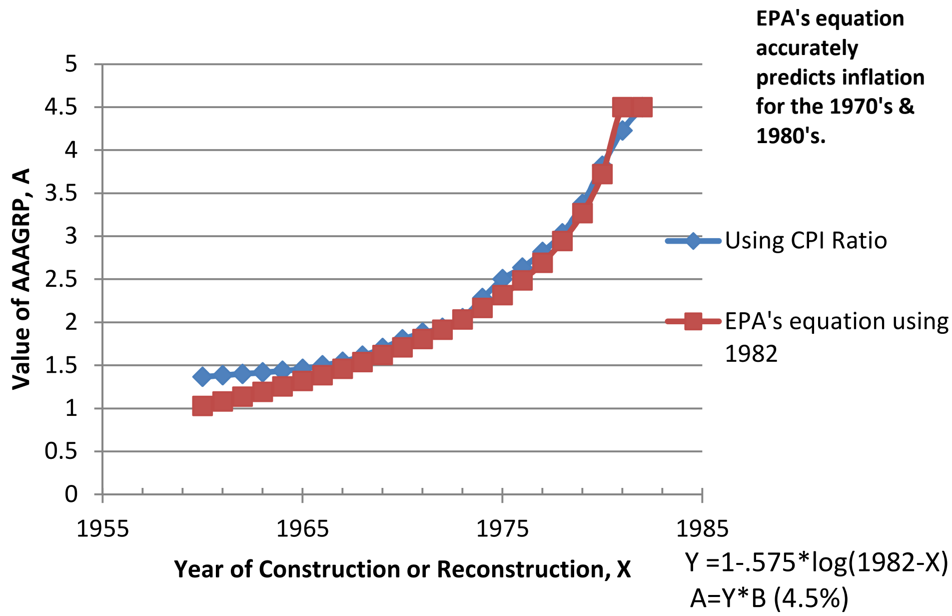


Figure 16-2 AAAGRP Discount from B=4.5% Method Comparison (1982).



17.0 API SUPPORTS EPA'S CONCLUSION REGARDING LIQUIDS UNLOADING REQUIREMENTS

Well-bore fluid dynamics and the portfolio of techniques, practices, and technologies that the industry uses to manage well-bore liquids are extremely complex. EPA has solicited significant comment on many aspects of liquids unloading operations within the preamble. Specifically EPA has sought comment (FR 56645) on:

- the level of methane and VOC emissions per unloading event, the number of unloading events per year, and the number of wells that perform liquids unloading.
- characteristics of the well that play a role in the frequency of liquids unloading events and the level of emissions,
- demonstrated techniques to reduce the emissions from liquids unloading events, including the use of smart automation, and the effectiveness and cost of these techniques,
- whether there are demonstrated techniques that can be employed on new wells that will reduce the emissions from liquids unloading events in the future, and
- whether emissions from liquids unloading can be captured and routed to a control device and whether this has been demonstrated in practice.

API prepared information in Comments in response to EPA's White Paper on Liquid Unloading, which has been included as an attachment to this document as Attachment D. Due to inadequate time in the comment period, API refers EPA to this set of comments previously submitted.

API also reiterates its previous position that to adequately evaluate options to reduce venting of wells and the emissions that result, it is necessary to understand the reasons that wells are vented, alternatives to venting that will still provide for well-bore liquid loading management, and the envelope of conditions where these alternatives are feasible. As EPA mentioned, emissions from liquids unloading are highly skewed and well-specific. This process is better left managed by companies under voluntary programs to manage, mitigate and implement. As such, API supports EPA's decision to not include requirements on liquids unloading.

18.0 NEXT GENERATION COMPLIANCE CONSIDERATIONS

18.1 EPA Should Not Be Seeking Comment Under Specific Rulemaking Packages For "Next Generation Compliance" Approaches That Could Be Expected To Have Broad Applicability.

The general next generation compliance topics for which EPA is seeking input in Section X of the preamble of the NSPS proposal (i.e. Use of Third-Party Verification, Third-Party Reporting, and expansions of Electronic Reporting) are broad issues that should not be addressed as part of sector-specific rulemakings.

Additionally, in whatever context considered, any Next Generation Compliance elements should clearly be shown to aid in the demonstration of compliance to EPA and not substitute non-EPA entities to perform EPA's responsibilities. The measures outlined in the preamble are unnecessarily punitive for a rule of general applicability.

18.2 Any EPA Actions Related To "Next Generation Compliance" Must Be Based Upon Proposed Rule Language.

No proposed rule text is provided that incorporates the issues on which EPA is soliciting comment in Section X of the preamble to the Subpart OOOO and Subpart OOOOa proposals. As a result, commenters do not have adequate clarity or notice of how the third party verification system would work and cannot ascertain whether the regulatory text would faithfully implement the concept. To resolve these problems, EPA would need to formally propose any third-party verification or third-party reporting requirements before finalizing any of them.

EPA has previously dealt with a similar situation and the corresponding need to provide comment on proposed requirements during the development of NSPS Subpart VVa and CISWI rules. *See* 73 Fed. Reg. 31,372, 31,373 (June 2, 2008) EPA determined that "[s]ection 60.482-11a is stayed from August 1, 2008 until further notice" because "these were first introduced in the final rule (indeed, with respect to connector monitoring, we explicitly stated in the proposal that we did not intend to address them in this rulemaking. Accordingly, <u>certain facilities may be out of compliance with requirements for which they had no notice or time to come into compliance</u>.") (emphasis added); *see also Portland Cement Ass'n v. E.P.A.*, 665 F.3d 177, 186 (2011) ("While we certainly require some degree of foresight on the part of commenters, we do not require telepathy. We should be especially reluctant to require advocates for affected industries and groups to anticipate every contingency. To hold otherwise would encourage strategic vagueness on the part of agencies and overly defensive, excessive commentary on the part of interested parties seeking to preserve all possible options for appeal. Neither response well serves the administrative process. Whatever warning EPA offered regarding CISWI was too vague and noncommittal to trigger a response from PCA. Indeed, as far as EPA did hint at its next steps, it suggested it would reevaluate the NESHAP standards after the CISWI definition was promulgated.").

18.3 Independent Third-Party Verification

In the preamble, EPA asserts that third-party verification "may" improve compliance[19]; however, EPA provides no information regarding how third-party verification would actually improve compliance. EPA does not explain why self-certification programs (like those under existing NSPS programs) would not work or why third party verification would improve compliance.

The following comments provide some additional comments discussing why API believes the options discussed in the preamble are neither legal nor necessary.

18.3.1 EPA Lacks Authority To Require Third-Party Verification.

As was noted in API's November 30, 2011 comments on the original Subpart OOOO proposal and EPA's request at that time for comment on innovative compliance options, EPA has again, in this rulemaking, not explained where it finds legal authority to impose a third-party verification requirement.

While EPA has authority to require such monitoring, recordkeeping, notification, and reporting requirements as are reasonably needed to assure compliance with Part 60 emissions standards. There is nothing on the face of the statute (and the statute cannot reasonably be construed as) authorizing EPA to require affected facilities to hire contractors to do EPA's work. EPA freely admitted in the 2011 Subpart OOOO proposal that assuring compliance with the well completion requirements would be "very difficult and burdensome for state, local and tribal agencies and EPA permitting staff, inspectors and compliance officers." As was the case in the original rulemaking, it again appears the purpose of the third-party verification requirement would be for the third-party verifiers to relieve burden on EPA. Simply put, EPA does not have authority under the CAA to require affected facilities to hire contractors to do work on behalf of the Agency.

Moreover, such a requirement would run afoul of the Anti-Deficiency Act. A third party verification requirement clearly would circumvent the limited Congressional budget appropriation for EPA enforcement activity. Such circumvention violates the prohibition against authorizing expenditures "exceeding an amount available in an appropriation or fund for the expenditure." 31 U.S.C. §1341(a)(1)(A).

For these reasons, even with a re-proposal, EPA is without authority to impose a third party verification requirement.

18.3.2 EPA's Logic On Requiring Third-Party Verification Of The Adequate Design Of Closed Vent Systems Is Flawed And Such A Requirement Is Unnecessary.

EPA requests comments to whether they should specify criteria by which a professional engineer (PE) might verify that a closed vent system is designed to accommodate all streams routed to the facility's control system, or whether they might cite to current engineering codes that produce the same outcome.

The need for third-party review of well-pad designs is unnecessary if EPA believes that the proposed rule language is sufficiently clear. Further, API believe EPA could exceed its CAA authority under 111(b)(5) and (h) if such a requirement were to be finalized. The oil and natural gas industry regularly designs and builds some of the most sophisticated engineered systems in use anywhere. As such, the value derived from a third-party verification of system design would seem to only be to provide an extension of EPA's manpower and expertise. As noted above, such a requirement would run afoul of the Anti-Deficiency Act.

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[19] FR 56648: "…well-structured third-party compliance monitoring and reporting may further improve compliance."

Oil and natural gas company engineering staff, with experience in the oil and natural gas industry and emissions control systems, and many with PE registration, are able to design systems effectively. This is especially true for modern hydraulically fractured shale oil and natural gas facilities, which are very different to the small single vertical well installations that dominated the industry in years past.

In addition to the above issues, the implementation of a third-party verification system would be complicated by the fact that any validation step would only have potential utility if it occurred prior to finalizing design and equipment construction. Specifically, any validation would need to take place prior to any required air permit applications are developed, adding time to what can already be a long process.

EPA should not attempt to expand any NSPS regulations by regulating the process or mechanical design of storage vessels or the closed vent systems through the use of third-party reviews of control devices or vapor recovery systems. Owners and operators are responsible for designing process equipment based on individual site process conditions and safety considerations. It would be a massive undertaking for EPA to attempt to write regulations regarding the specific "proper" design of storage vessels and closed vent systems. It is doubtful if EPA could provide enough flexibility in process and mechanical design of equipment regulations to cover all the unique process conditions at individual facilities.

Also, EPA has failed to take into consideration the availability of enough qualified consultants to perform process design analysis and compliance auditing. It is one thing to require third-party contracting, but quite another to find qualified contractors. EPA's proposal to limit perceived conflicts of interests would further shrink this limited pool of qualified contractors.

18.3.3 EPA's Request For Details On Pressure Monitoring Systems For Storage Vessels Is Unnecessary.

In the preamble, EPA requests comment as to what types of cost-effective pressure monitoring systems can be utilized to ensure that the pressure settings on relief devices and thief hatches are not lower than the operating pressure in the closed vent to the control device and what types of reporting from such systems should be required, such as through a supervisory control and data acquisition (SCADA) system (FR 56649).

While recognizing the importance of proper design and operation of equipment, it is inappropriate for EPA to be considering this level of engineering detail as part of rulemaking. EPA has already specified requirements for inspecting closed vent systems and performing inspections to identify any leaks and these measures are adequate to address any potential issues related to how systems are designed and operated. Additionally, the design of well pads and tank batteries undergo engineering and safety reviews as part of their development. These reviews serve to ensure that materials flowing from wells are appropriately captured and routed as intended.

18.3.4 EPA Should Not Presume Industry Will Fail To Properly Implement The Proposed Leak Detection And Repair Requirements.

In Section X of the NSPS preamble, EPA solicits comments on an audit program of the collection of fugitive emissions components at well sites and compressor stations (FR 56649).

EPA explained the request for input on this matter based on the comment that they "have ample experience from our enhanced LDAR efforts under our Air Toxics Enforcement Initiative, that even when methods are in place, routine monitoring for fugitives may not be as effective in practice as in design." This analogy is flawed for numerous reasons, not the least of which is that most issues identified by the Air Toxics Enforcement Initiative relate to alleged failures related to the implementation of M21-based LDAR programs at facilities with thousands, and in some cases, up to hundreds of thousands of individual components subject to monitoring. It is noted that the scope of the oil and natural gas site operations are significantly different than any situations addressed in the enforcement initiative cited.

In the preamble (FR 56649-56650), EPA is quite detailed in describing the potential structure of an audit program for LDAR compliance as well as alternative auditor/auditing approaches with "less rigorous" independence criteria. Meanwhile, within the proposed Subpart OOOOa provisions, EPA has provided specific requirements related to the recordkeeping and work practices that must be followed as part of the leak detection requirements (see Section 27.0 of these comments for proposed provisions).

EPA is right that there will be challenges with the implementation of the LDAR requirements as proposed. See Section 27.0 of these comments for additional discussion of API's recommendations related to suggested improvements to the proposal rule to help address these challenges.

However, API believes it is unwarranted for EPA to assume or anticipate that industry will not comply with the regulatory requirements. As a result, it is inappropriate for EPA to preemptively require additional compliance measures that have been historically used as part of consent orders resulting from enforcement actions.

Even if EPA has statutory authority to require third party verifications, the same factors that make compliance assurance difficult and burdensome for State and EPA staff (such as geographically dispersed and remote locations) would make any use of third party verification costly to the regulated industry. In the proposed rulemaking and supporting documentation, EPA does not quantify or evaluate in the Regulatory Impact Analysis or proposed rule the costs associated with third party verification. In the GHG reporting program, EPA similarly proposed a third-party verification of the GHG report and declined to include in its final rule. See 74 Fed. Reg. 56,520, 56,5282-84 (October 30, 2009) (for a national program involving significant reporting such as the GHG reporting program, third-party verification was not the preferred approach). Specifically, EPA expressed concerns that a third party verification program: (1) would require EPA to establish third-party verification protocols; (2) would require EPA to develop a system to qualify and accredit third party verifiers; and (3) would require EPA to develop and administer a process to ensure verifiers do not have conflicts of interest. EPA thought that setting up a third-party program would slow down implementation of the rule. EPA also estimated that the first year of the program (with a third-party verification requirement) would cost $42 million. GHG reporting rule and Subpart OOOOa would cover a similar scope and thus raise similar concerns as were raised in the GHG reporting rule. Accordingly, any action by EPA to incorporate verification into Subpart OOOOa must progress through a formal rulemaking process with proper assessment of cost-benefit of the additional requirements.

18.3.5 Transparency And Public Access To Information Resulting From Potential Auditing Provisions (FR 56650).

"EPA seeks comment on whether, and to what extent, the public should have access to the compliance reports, portions or summaries of them and/or any other information or documentation produced pursuant to the auditing provisions. EPA is also considering the approach it should take to balance public access to the audits and the need to protect Confidential Business Information (CBI). To balance these potentially competing interests, EPA is reviewing a variety of approaches that may include limiting public access to portions of the audits and/or posting public audit grades or scores to inform the public of the auditing outcomes without compromising confidential or sensitive information. EPA seeks comment on these transparency and public access to information issues in the context of the proposed auditing provisions."

As stated above, API believes a requirement to use third-party auditing would exceed EPA's CAA authority, is unnecessary and any such program would face many changes to design and implementation. Even if EPA has the authority , it is necessary to include clear requirements in the rulemaking proposal regarding what information would be required to be submitted to the EPA or made available upon request.

18.4 Third-Party Data Reporting (e.g. Vendors)

18.4.1 EPA's Concept Of Having Control Device Vendors Provide Direct Submittals To The Agency Is Both Flawed And Unnecessary.

In Section X of the preamble, EPA solicits comment on potential third-party approaches such as the "post card" reporting described above that could be implemented to streamline and enhance compliance (FR 56651).

In the preamble, EPA appropriately acknowledges the limitations to how such an approach might work for the oil and natural gas sector:

> *"We understand the issues for this sector, with making the ''postcard'' model work as we envisioned. One of the issues is related to the granularity of the reporting by the manufacturer as compared to the reporting by the source to the EPA or delegated authority. For example, the manufacturer may only know that they sold 500 units of a particular control device, but may not know where it is actually installed. Lack of a unique ''user ID'' being reported by both sides can limit the utility of the postcard model in this instance."*

Requiring manufacturers to provide data to EPA regarding the number of control devices sold to different companies adds no value and could even likely be a source of confusion to reconcile which specific piece of equipment went where. Further, in many cases where the same model control device is installed in many locations, what matters is how that equipment is operated on site, not what serial number is on a particular control device.

For example, when an owner or operator purchases a "certified control device" from a vendor, the owner would be required to submit the model and serial number to the Agency. Additionally the vendor would be required to submit the same information, thereby confirming what the owner had reported. This is unnecessary burden on both the operator and the vendor, and is unprecedented in its duplicative reporting. As noted above, owner/operators will often buy units in bulk and not install these units for months or even years. This will cause unnecessary tracking and verification of installations against vendor-supplied data to EPA. The serial numbers of equipment are available at all times and if a question is ever raised about the unit, the Agency could then contact the vendor with any questions for verification. Having dual reporting will continually lead to confusion and unnecessary time spent reconciling equipment versus reporting.

In the preamble, EPA states:

> *"…a primary concern is that an owner or operator would install a control device, and not conduct a performance test, claiming that they installed a device listed on the Oil and natural gas page. We believe that we can build on the success of GIS imbedded digital photos for green completions (''REC PIX''), already in the rule, by developing a similar requirement for installed manufacturer tested control devices. Enhancing the records and reports by requiring specifics of the control device (make, model and serial number) and requiring the digital picture, will allow us to match a particular control device at a specific location with control device models listed on the Oil and natural gas page. Having this information electronically reported to CEDRI will further enhance our ability to evaluate compliance with the rule."*

API questions the success EPA claims regarding the use of GIS imbedded digital photos for green completions (''REC PIX''), already in the rule. Many API member companies are not utilizing the photo – an optional approach for recordkeeping – for affected gas wells. API disagrees strongly with EPA's assertion that widespread misrepresentation by industry is or will be a problem. EPA is adding burden when they will not gain any more benefit from requiring a photo versus seeking submittal of the make and model of the control device.

EPA further states:

> *"While we are soliciting comment on third-party reporting by combustor vendors directly to the EPA, we propose to require that owners or operators include information regarding purchase of a pre-tested combustor model in their Notice of Compliance Status as part of the first annual report following the compliance period in which the combustor commences operation. The information would include (1) make, model and serial number of the purchased device; (2) date of purchase; (3) inlet gas flow rate; (4) latitude and longitude of the emission source being controlled by the combustor; (5) digital GIS and date stamp-imbedded photo of the combustor once it is installed; and (6) certification of continuous compliance. The owner or operator would be required to submit information to CEDRI in lieu of a field performance test."*

The above statement is misleading; the use of the photo is optional, consistent with the reduced emission completion option. The proposed rule includes the following language under §60.5420a(c)(5)(vi)(G):

> *"As an alternative to the requirements of paragraph (c)(5)(vi)(D) of this section, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the storage vessel and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the storage vessel and control device 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."*

18.5 Electronic Reporting - EPA should not require the reporting of data related to rule compliance in multiple locations since this adds cost with no benefit and violates the First Amendment

In the preamble, EPA solicited comments on potentially requiring owners and operators of affected facilities to report quantitative environmental results on their corporate maintained web sites (FR 56652):

> *"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)."*

It is inappropriate for EPA to require the reporting of environmental performance on corporate maintained websites; it far exceeds any CAA authority to require records and violates the first amendment. Any requirement to alter the company's website would be a content base restriction subject to strict scrutiny. See, *Reed v. Town of Gilbert,* 135 S. Ct. 2218 (2015). And without conceding that this is commercial speech, this would not even meet the test for appropriate regulation of commercial speech. In *Central Hudson Gas & Elec. Corp v. Public Service Comm'n* , 447 U.S 557(1980), 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." *Id.* at 566. Should EPA adopt this requirement it would fail both. This data is already being reporting to the agency as required under the existing rule, and the to one degree or another already provided to the public. To require reporting of the same or similar data via company websites is both unnecessary does further advance the government interest, and is unequivocally more burdensome.[20] EPA should not pursue this requirement.

19.0 EPA SHOULD NOT FINALIZE RETROACTIVE REQUIREMENTS TO SUBPART OOOO

EPA proposed several new requirements for control devices and closed vent systems to Subpart OOOO that could only be viewed as new requirements to be applied retroactively to affected facilities initially constructed between August 23, 2011 and September 18, 2015. This is inappropriate as NSPS rule changes should only be prospective and not retrospective. Amongst the numerous changes, proposed paragraph §60.5370(d) encapsulates the problem best by stating: *You are deemed to be in compliance with this subpart if you are in compliance with all applicable provisions of Subpart OOOOa of this part.* This suggests that new requirements in Subpart OOOOa for Subpart OOOO affected facilities will be applicable when subpart OOOOa is finalized. Examples of the specific problems cause by this retroactivity can be found in Sections 14.1 and 25.6.1 for detailed comments on this matter for bypass devices and storage vessels, respectively.

The D.C. Circuit has made it clear that regulatory agencies do not have authority to impose retroactive regulations unless that authority is expressly provided by Congress. Georgetown University Hospital v. Bowen, 821 F. 2d 750, 757 (D.C. Cir. 1987) (absent clear Congressional intent to the contrary, "legislative rules [should] be given future effect only."). There is no indication in § 111 or the CAA as a whole that Congress granted EPA authority to impose retroactive requirements under an NSPS. Therefore, EPA should make it clear in this rule that all new requirements apply prospectively and only to newly affected sources. The only purpose for modifying any part in the existing Subpart OOOO should be to end date the rule and correct issues that do not add new regulatory burden since it is being replaced with Subpart OOOOa. EPA should remove all new compliance requirements being proposed in subpart OOOO and only finalize changes to paragraphs §60.5360 and §60.5365 which 1) end date the applicability of Subpart OOOO and 2) technical clarifications.

20.0 EPA SHOULD PROVIDE AN EXEMPTION FOR SOURCES ALREADY REGULATED BY AN ENFORCEABLE STATE PROGRAM

Numerous states have been proactive in developing regulatory programs to address emissions from the oil and natural gas operations. Clearly EPA is well aware of these programs, as Wyoming and Colorado programs are mentioned numerous times in the September 18, 2015 preamble for the proposed regulations. In fact, EPA relied heavily on aspects of the programs in these states in developing the proposed NSPS subpart OOOOa requirements. EPA also utilized technical information developed by the states to assist in the estimation of the impacts of the proposed federal rules.

The existing regulatory programs in Colorado and Wyoming, as well as other states, are in full force and are being successfully implementing and achieving reductions in VOC and methane emissions. As new

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[20] Costs for building and maintaining such a website could easily each $15,000 or more annually per company, depending on the number of reports and site configuration.

oil and natural gas operations begin, they are subject to these regulations. And these regulations cover the same emission sources, typically with the same basic control requirements, as the proposed subpart OOOOa. If EPA moves forward with subpart OOOOa as proposed, the result will be that sources will be subject to overlapping and duplicative requirements. This situation will result in increased financial burden for the oil and gas industry without any environmental benefit.

In order to avoid this situation, API requests that EPA include provisions in the final subpart OOOOa that would clarify that sources that are subject to legally and practically enforceable requirements that address the same emission sources are not affected facilities under the rule. The precedent for this provision has already been established for this industry, as storage vessels can avoid being a subpart OOOO affected facility by having legally and practically enforceable requirements – see §60.5365(e).

For the fugitive emission standards for well sites and compressor stations, this request is discussed in detail in 27.2.2. However, API believes that it is warranted that such a provision also apply to well completions, compressors, and pneumatic pumps.

API recommends the following regulatory changes in §60.5365a.

§60.5365a

(a)(5) A well completion operation in compliance with a legally and practically enforceable requirement that requires the reduction of VOC or methane is not an affected facility.

(b) Each centrifugal compressor affected facility, which is a single centrifugal compressor using wet seals. A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart. A centrifugal compressor in compliance with a legally and practically enforceable requirement that requires at least a 95% reduction in VOC or methane emissions is not an affected facility.

(c) Each reciprocating compressor affected facility, which is a single reciprocating compressor. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart. A reciprocating compressor in compliance with a legally and practically enforceable requirement that requires the reduction of VOC or methane is not an affected facility.

(h)(1) For natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas driven chemical/methanol pump or natural gas-driven diaphragm pump.
(2) For locations other than natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven chemical/methanol pump or natural gas-driven diaphragm pump for which a control device is located on site. A pneumatic pump that is in compliance with a legally and practically enforceable requirement that requires the reduction of VOC or methane is not an affected facility.

Note that there are additional revisions to §60.5365a(h)(1) and §60.5365a(h)(2) proposed in Section 24.4.1 and Section 24.4.5. See 24.4.5 for combined language.

Recommended regulatory changes for the fugitive program are provided in section 27.2.12.

Also, additional changes are recommended to various aspects of §60.5365a throughout this comment document. Specifically, see sections 22.2.2 and 22.2.3 for recommended changes for wells (completions), 24.3.3, 24.4.1, and 24.4.5 for pneumatic pumps, 25.1 and 25.2 for storage vessels, and 27.2.12.

21.0 SOCIAL COST OF METHANE

21.1 EPA's Use Of A Social Cost Of Methane Value Should Undergo Notice And Comment.

The benefits of the proposed rule are estimated using a social cost of methane (SC-CH_4), which has been derived from the approach the Interagency Working Group ("IWG") – a group of thirteen federal agencies developed for the Social Cost of Carbon (SCC). EPA's selected value for SC-CH_4 in this proposed rulemaking is arbitrarily taken from one scientific report that attempts to find an equivalent SC-CH_4 from the SCC, and for which EPA only requested a peer review, not formal public review and commenting. (80 Fed. Reg. at 56655) Moreover, even if the SC-CH_4 estimate development process was transparent, rigorous, and adequately peer-reviewed, the modeling conducted in this effort does not offer a reasonably acceptable range of accuracy for use in policymaking. In addition, the EPA has failed to disclose and quantify key uncertainties to inform decision makers and the public about the effects and uncertainties of alternative regulatory actions as required by OMB. For these and the reasons elaborated in this section, the SC-CH_4 should not be used to determine benefits as part of this rulemaking.

21.2 Assessment Of EPA's Overall Benefit-Cost Analysis

The EPA has prepared a Regulatory Impact Analysis (RIA) of the proposed Subpart OOOOa rules for reducing emissions at newly constructed, reconstructed, and modified oil and natural gas facilities. RIAs are required for rules that will have an annual impact in excess of $100 million. Based on Executive Orders 12866 and 13563, the EPA is required to use the best available scientific and economic information available to quantify the benefits and costs of proposed rules.

EPA has estimated the benefits of the proposed rule using the SC-CH_4. Annualized engineering costs are estimated for each source based on capital costs, one-time labor costs, and on-going annual costs. EPA projected both the total costs and total benefits for the first year the full rule is in effect (2020) and for 2025 to demonstrate how affected sources accumulate over time. The net benefits in these years are the difference between the total benefits and costs, measured in 2012 dollars.

EPA's benefit-cost analysis as presented in the RIA shows that the overall benefits estimated to support the rulemaking are only marginally higher than the overall costs. For the selected regulatory option (Option 2), EPA estimates that the annual costs of the proposed rule will range from $320 to $420 million by 2025, and the annual benefits will be between $460 and $550 million (in 2012 dollars, using a three percent discount rate).

Reviewing the benefit-cost analysis more closely identifies aspects of the regulation where EPA is pursuing regulation despite their own analysis indicating that the costs outweigh the benefits for specific elements of the regulation. Within the RIA, the EPA does not provide annualized benefits for reducing fugitive emissions at both oil and natural gas well sites separately; rather, it reports only a single annual value for fugitive emissions from well sites. In 2025, the RIA estimates annual costs will be $160 million and that annual benefits at a 3 percent discount rate will be $150 million. Thus, as a group, fugitive emission controls for well sites do not pass the benefit cost test (meaning that costs are higher than benefits), even using the EPA's benefit and cost numbers.

21.3 Addressing Errors In EPA's Overall Benefit-Cost Analysis

A review of EPA's analysis of baseline emissions, emission reductions, and cost estimates is detailed in Attachment E. A number of issues were found with the EPA cost estimates, as well as the assumptions underlying the emission reduction estimates. Table 21-1 presents the benefit cost analysis estimates for 2025 from EPA compared to the estimates that correct some of the issues identified. The second set of columns shown in Table 21-1 show the estimated benefits and costs after correcting the key issues found, including:

- Oil well completions: EPA underestimated the cost of combustion controls for oil well completions. An adjustment was also made to reflect the fact that many hydraulically fractured development oil well completions are controlled in the baseline. It was assumed that 25% of oil well completions are controlled in the baseline as a conservatively low estimate. Adjusting the estimated costs and the emission reduction estimate to reflect the fact that many hydraulically fractured development oil well completions are controlled in the baseline, the costs are higher than benefits.

- Fugitives from well pads: EPA overestimated the emission reductions for fugitive emissions in their analysis. The model plant baseline emissions for both oil and natural gas well sites were estimated by rounding up the counts of major equipment at a well site and then multiplying by the component counts per major equipment. The resulting estimate was an overstatement of baseline emissions and corresponding emission reductions of 30-35 percent. EPA also excluded many cost elements in their estimates for semi-annual OGI leak screening and repair for well sites. Table 21-1 shows the impact of correcting the major flaws with the EPA cost estimates and correcting the estimated component counts for the model plants. These adjustments show that both oil and natural gas well sites fail the benefit cost test.

- Pneumatic Pumps: Several corrections were made to the estimates for pneumatic pumps that significantly change the net benefits estimate. These corrections include: a) adjusting the annual operating time for diaphragm pumps to 4 months of the year, on average; and b) correcting the costs of routing the pump vent to an existing control device, consistent with the estimate EPA used for wet seal compressor vents.

Based on the analyses, the total benefits in 2025 are around $400 million (vs. EPA's $460 million) and the costs are $810 million (vs. EPA's $310 million) for EPA's preferred regulatory approach (Option 2). Therefore, the overall proposed regulatory program results in a net benefit of around -$410 million, and would not pass a benefit-cost test. Stated differently, the societal costs are significantly higher than the societal benefits from the methane reductions, even using the EPA's estimated SC-CH_4 of $1,500/metric tonne in 2025, which as noted, is inappropriate for use in this analysis as stated below. Additionally, independent review by NERA found that the social net costs could be greater when specific factors ignored by EPA were included in the estimate of the social cost of methane.[21] API used NERA's calculation of the social cost of methane and applied that to the revised emission reductions estimated by ERM and ERM's corrected cost estimates of the proposed regulation. This calculation showed that the net costs to society of the proposed regulation could exceed $1 billion in 2025.

21.4 Precedence Issues Related To Prior Social Cost Of Carbon Publication.

The benefits of the proposed rule are estimated using the SC-CH_4, which has been derived from the approach the USG uses for estimating the SCC. Therefore, the SC-CH_4 inherits many of the same weaknesses as the SCC estimates.

The methodology used by EPA to estimate SC-CH_4 is similar to the EPA's approach to estimating SCC in the following ways:

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[21] NERA, "Technical Comments on the Social Cost of Methane as used in the Regulatory Impact Analysis of the Proposed Emissions Standards for New and Modified Sources in the Oil and Natural Gas Sector." December 2015.

- Uses the same three Integrated Assessment Models (IAMs).
- Uses the same five same socio-economic and emissions scenarios.
- Uses the same discount rates.
- Uses the same approach for averaging social costs across scenarios and IAMs.

As discussed in Section 4.3.1 of the RIA, EPA asked three peer-reviewers to provide an assessment of the SC-CH_4 approach and concluded that the reviewers generally agree that the SC-CH_4 estimates are "consistent" with the SCC estimates. Moreover, because Office of Management and Budget (OMB) guidance supports the use of SCC estimates, the EPA has concluded that using the SC-CH_4 estimates is an "analytical improvement" over their exclusion[22].

[22] P. 4-15 of RIA: "The fact that the reviewers agree that the SC-CH_4 estimates are generally consistent with the SC-CO_2 estimates that are recommended by OMB's guidance on valuing CO_2 emissions reductions, leads the EPA to conclude that use of the SC-CH_4 estimates is an analytical improvement over excluding methane emissions from the monetized portion of the benefit cost analysis."

Table 21-1 Comparison of 2025 Annual Benefits and Costs – Option 2, Low Impact, Discount Rate 3%.

Source	Emission Point	EPA Estimates from RIA				ERM's Estimates			
		Reduced CH4 Emissions (Mt)	CH4 Benefits ($M)	Annualized Cost ($M)	Net Benefits ($M)	Reduced CH4 Emissions (Mt)	CH4 Benefits ($M)	Annualized Cost ($M)	Net Benefits ($M)
Well Completions	Hydraulic Fracturing – Development	117,934	$177	$120	$57	122,908	$184	$208	($24)
	Hydraulic Fracturing – Exploration	9,979	$15	$4	$11	10,284	$15	$12	$4
Fugitive Emissions	Well Pads	99,790	$150	$160	($10)	68,838	$103	$508	($405)
	Oil Wells	*33,980*	*$51*	*$119*	*($68)*	*21,685*	*$33*	*$338*	*($305)*
	Natural Gas Wells	*71,651*	*$108*	*$46*	*$61*	*47,153*	*$71*	*$171*	*($100)*
	Gathering & Boosting Stations	29,937	$45	$17	$28	Not Evaluated (used EPA's estimate)			
	Transmission Compressor Stations	9,072	$14	$3	$11	Not Evaluated (used EPA's estimate)			
Pneumatic Pumps	Well Pads	29,030	$44	$5	$38	11,186	$17	$57	($40)
Pneumatic Controllers	Transmission & Storage Stations	7,983	$12	$0.8	$11	Not Evaluated (used EPA's estimate)			
Reciprocating Compressors	Transmission & Storage Stations	608	$0.9	$0.7	$0.2	Not Evaluated (used EPA's estimate)			
Centrifugal Compressors	Transmission & Storage Stations	3,175	$5	$0	$5	Not Evaluated (used EPA's estimate)			
Total		307,508	$460	$310	$150	263,992	$396	$806	($410)

API believes that the use of the $SC\text{-}CH_4$ estimates is not warranted. Two primary reasons are as follows:

- The three peer reviewers' endorsement of the "consistency" of the $SC\text{-}CH_4$ estimates was in fact more modest than the EPA concludes. Further, the reviewers identified uncertainties with the approach being used. One reviewer commented that the fact that methane is not explicitly modeled in two out of the three IAMs used makes the approach inconsistent with SCC. A second reviewer commented that the emissions perturbation approach used for methane is inconsistent with the approach used for SCC and the impact of the difference is not understood. More importantly, the reviewer argued that neither the SCC approach nor the IAMs themselves have been peer-reviewed, which mean the SCC and $SC\text{-}CH_4$ estimates are likely not reliable.
- All of the problems with estimating the SCC have been inherited by the $SC\text{-}CH_4$ estimates. The issues associated with the SCC estimates include: differences in the climate outcomes of the three IAMs; significant differences in the damage functions between models; and issues with the averaging approach used to synthesize results. These challenges seriously affect the reliability and usefulness of the SCC and $SC\text{-}CH_4$ estimates in the foreseeable future.

The IAMs show significant differences in the climate outcome of the modeled results to the same increase in emissions. The three models project different temperature changes and sea level rise estimates resulting from the same increase in emissions and same underlying socioeconomic conditions. The temperature responses result from differences in the modeling of the carbon cycle, non-CO_2 radiative forcing, and sensitivity. Even in the short-term, through 2040, the IAMs can yield temperature changes that vary by a factor of two.

The damage functions linked to these temperature changes and sea level rise estimates are also very different, corresponding to a wide range of economic impacts. For example, one IAM shows gains in GDP through 2100 for some scenarios with increased emissions, while the other two IAMs show losses. The three models also show wide variation in the impact on the GDP of different countries and different types of economic costs (i.e. agriculture, heating and cooling). The differences in the structure of the models, which lead to significant differences in the damages estimates, are not well understood or explained.

The USG approach averages the SCC models across different socioeconomic scenarios to form a single estimate of the SCC for a particular discount rate. Inconsistencies in the models, and the fact that they may not be truly independent, may make such averaging inappropriate. Averaging assumes that each estimate is equally reliable and obscures the true uncertainty about the SCC that exists in the scientific literature. In addition, other key sources of uncertainty, such as economic variables, the damage functions, and temperature change can have significant impacts on social costs and are highly uncertain, Gillingham et. al. 2015. Modeling Uncertainty in Climate Change: A Multi-model Comparison. Cowles Foundation Working Paper. No. 2022. These issues need to be better understood before using SCC and $SCM\text{-}CH_4$ in policy making.

One reviewers' assessment of the IAMs led him to conclude: "These models have crucial flaws that make them close to useless as tools for policy analysis: certain inputs (e.g., the discount rate) are arbitrary, but have huge effects on the SCC estimates the models produce; the models' descriptions of the impact of climate change are completely ad hoc, with no theoretical or empirical foundation; and the models can tell us nothing about the most important driver of the SCC, the possibility of a catastrophic climate outcome.

IAM-based analyses of climate policy create a perception of knowledge and precision, but that perception is illusory and misleading."[23]

21.5 Discount Rate Chosen Is Not Appropriate For This Rulemaking.

The selection of a 2.5% discount rate by EPA is not appropriate given the shorter atmospheric lifespan of methane. EPA justified the use of a 2.5% discount rate for the SCC by citing the long atmospheric lifespan of carbon dioxide which may remain in the atmosphere for several hundred years. However, methane dissipates significantly faster than carbon dioxide, typically lasting 80 to 100 years, eliminating the potential intergenerational equity impacts or uncertainty about future growth that the IWG used for justification in the SCC. As NERA detailed, changing the discount rate by just one half of a percent could lower the SC-CH_4 by as much as 37% in 2020.

21.6 EPA should identify and apply only the domestic impacts.

For the SC-CH_4, EPA does not report the net benefits to the United States; it only reports the global net benefits. Both estimates are relevant to the assessment of the value of the rule to U.S. taxpayers. However, using only the global benefits instead of domestic benefits is not consistent with past practice in benefit cost analyses, and is contrary to OMB Circular A-4. In EPA's prior analyses of the SCC, it estimates that between 17% and 23% of global SCC benefits actually accrue to the U.S. Using the PAGE and FUND models, NERA estimated that the using only the domestic damages would lower the SC-CH_4 by 76% to 92% in 2020, respectively.[24] Attachment E shows that the 2025 annual net benefits to the U.S. will range between $-1.1 and -$0.6 billion. By considering only the global benefits rather than domestic benefits, the EPA is suggesting that the benefits the U.S. can expect from the proposed rule are significantly larger than what may actually accrue to the U.S.

A complete review of EPA's analysis of baseline emissions conducted , emission reduction and cost estimates is detailed in Attachment E.

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[23] Pindyck, Robert. 2013. "Climate Change Policy: What Do the Models Tell US". Journal of Economic Literature 2013, 51(3): 860-872.

[24] NERA 2015

TECHNICAL COMMENTS

22.0 OIL WELL COMPLETIONS

22.1 Applicability/Definitions

22.1.1 The Proposed Definition In §60.5430a For Low Pressure Well Is Inconsistent With The Amended Definition Of Low Pressure Well In 80 FR 48268, August 12, 2015 §60.5430.

EPA's proposed definition for low pressure well in §60.5430a is the following:

> *"Low pressure 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 vertical well depth (in feet) minus 67.578 psia is less than the flow line pressure at the sales meter."*

API supports the following amendment to this definition that was finalized by EPA in §60.5430 (80 FR 48268) on August 12, 2015 as the following:

Low pressure 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.

22.2 Exemptions From REC Requirements For Certain Hydraulically Fractured Oil Wells

22.2.1 EPA Is Correct When It States In The Preamble (FR 56633) That "Oil Wells Cannot Perform A REC If There Is Not Sufficient Well Pressure Or Gas Content During The Well Completion To Operate The Surface Equipment Required For A REC."

In order to operate a two or three phase gas/liquid separator there must be both sufficient wellhead pressure and a sufficient quantity of gas in the flowback fluid. Lack of insufficient gas volumes results in the inability to operate a separator during flowback, which makes both a REC and combustion of emissions technically infeasible. The regulation should not require operators to set up a separator on-site and attempt to utilize the separator when it is known that it will never be operated. This results in extraneous costs for no tangible emission reduction since there is insufficient gas to operate the separator. Therefore, there are several instances where EPA should provide exemptions for the proposed REC requirements. Some of these exemptions may overlap since all involve the technical infeasibility of operating a gas/liquid separator in order to conduct a REC.

22.2.2 API Agrees With A Minimum GOR Of 300 Scf/Bbl As An Exemption Threshold In The Definition Of A Well Affected Facility Per § 60.5365a(A) But Recommends Language Be Amended For Consistency With The Greenhouse Gas Reporting Program.

API supports EPA's conclusion that hydraulically fractured oil wells with a gas-to-oil ratio (GOR) of less than 300 scf/bbl of oil produced should not be affected facilities subject to the well completion provisions of Subpart OOOOa. EPA's reasoning on FR 56633 for exempting low GOR oil wells is accurate. Operators in a given basin or field that are drilling and completing wells from specific formations generally have good knowledge and understanding of whether REC separator equipment can technically be operated on similar wells. There is also sufficient data on well GORs drilled in the same area and in the same formations.

API further recommends EPA amend the exemption language to be consistent with the Greenhouse Gas Reporting Program in such that the definition of the gas well affected facility in §60.5365a(a) be amended to the following:

> Each well affected facility, which is a single well that conducts a well completion operation following hydraulic fracturing or refracturing and has a gas-to-oil ratio of greater than 300 scf of gas per stock tank barrel of oil produced. The provisions of this paragraph do not affect the affected facility status of well.

22.2.3 Wells Requiring Artificial Lift In Order To Flow Back The Completions Fluids Should Be Exempt From The Well Completion Affected Facility.

EPA should exempt hydraulically fractured oil wells that require artificial lift in order to flow back the completions fluid. Many oil reservoirs have pressure that is insufficient for wells to naturally flow even after hydraulic fracturing. This can be evidenced by the prevalence of artificial lift equipment such as rod pumps visible across the landscape of many oil producing areas. In order to operate a two or three phase gas/liquid separator there must be both sufficient wellhead pressure and a sufficient quantity of gas in the flowback fluid. Lack of insufficient gas volumes results in the inability to operate a separator during flowback, which makes both a REC and combustion of emissions technically infeasible. The regulation should not require operators to set up a separator on-site and attempt to utilize the separator when it is known that it will never be operated. This results in extraneous costs for minimal emission reductions since there is insufficient gas available to operate the separator.

Examples of this are reservoirs in the Permian Basin where horizontal drilling is used to extend the life of existing producing formations. Many oil wells that are hydraulically fractured do not have sufficient reservoir pressure to flowback and there is insufficient gas to flare. One API Company estimates that approximately 30% of its hydraulically fractured horizontal wells and 80% of its hydraulically fractured vertical wells in the Permian Basin require artificial lift to flowback. Instead, following a hydraulic fracture, rod pumps are installed on the wells to artificially lift the fracture fluids either to fracture tanks or storage vessels. Other examples include reservoirs in the north central East Texas basin which produce heavy black oil, also called "dead oil" because there is no associated gas produced with the oil. In this area, gas to operate separation must be purchased as it is not available from well production.

API recommends the suggested revision to the definition of well affected facility:

> **§60.5365a(a)** Each well affected facility, which is a single well that conducts a well completion operation following hydraulic fracturing or refracturing and has a gas-to-oil ratio of greater than 300 scf of gas per stock tank barrel of oil produced. Wells that must use artificial lift equipment to flowback completion fluid are not well affected facilities.

API also recommends the addition of the following definition for Artificial Lift Equipment in §60.5430a:

> *Artificial Lift Equipment* means the use of mechanical pumps (e.g., rod pumps or electric submersible pumps) to flowback fluids from a well.

22.2.4 EPA Should Exempt Inert Gas Venting During Separation Flowback Stage

The language in §60.5375a(a)(3) and §60.5375a(f)(2) implies all gas must be recovered to a completion combustion device if it cannot be routed to pipe "except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterway when wells are in the separation flowback stage. Nitrogen foam may be used to complete a well, as is done for oil wells in the San Juan Basin in northwest New Mexico. In this situation, the operation of a separator may be feasible, but the initial gas quality "is not of salable quality" nor can the produced gas t be combusted due to the high nitrogen (N_2) content. N_2 is an inert gas, and therefore it is technically infeasible to combust the gas. The proposed language is required to clarify that in this specific situation, where gas cannot go to pipe for one of the acceptable reasons provided by EPA and also cannot be combusted due to technical infeasibility, the gas can be vented during the separation flowback stage. Note that in addition to N_2, the content of other inert gases such as CO_2 or hydrogen sulfide (H_2S) may also disallow the use of a combustion device due to high inert gas composition.

In addition, EPA apparently intended to allow venting of the noncombustible flowback gas but neglected to include it in the rule text language.

"… [EPA] are proposing an operational standard for subcategory 1 wells that would require a combination of gas capture and recovery and completion combustion devices …, with provisions for venting in lieu of combustion for … or for periods when the flowback gas is noncombustible." 80 FR 56630.

"…[EPA] are proposing an operational standard for subcategory 2 well completions … with provisions for venting in lieu of combustion for … or for periods when the flowback gas is noncombustible." 80 FR 56632.

Therefore, API recommends the following clarifications be added to the rule:

> §60.5375a(a)(3) You must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways or it is technically infeasible due to inert gas concentration.
>
> §60.5375a(f)(2) You must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways or it is technically infeasible due to inert gas concentration.

22.2.5 EPA Should Clarify That A Separator Is Not Required To Be Onsite During The Initial Flowback Stage When It Is Technically Infeasible To Operate.

Certain wells produce flowback with stable entrained gas, foam, emulsion, or infrequent slugging gas flow. Gas from hydraulically fractured oil well flowback often initially starts appearing in slugs before the flow begins to stabilize. Infrequent slugs of gas may drive liquids and/or foams into the gas lines unless a prohibitively large gas space above the liquid/foam is maintained in the separator (see section 12.1). These conditions do not supply a sufficiently steady stream of gas to operate a separator such that flowback from these wells never leave the initial flowback stage prior to production In these situations, it is unclear if operators are required to rent separation equipment to have onsite even knowing the equipment would never be utilized due to well characteristics and engineering constraint. API believes it was EPA's intent to not require separation equipment to be onsite during the initial flowback stage based on the definitions proposed in §60.5430a and the requirements in §60.5375a(a)(1)(i) and §60.5375a(a)(1)(ii). This would result in extraneous compliance costs for minimal emission reduction since there is insufficient gas to operate the separation equipment. Therefore, API requests EPA clarify that well completion operations that remain in the initial flowback stage through the start of production are not required to have a separator onsite or exempt wells where field experience indicates that flowback fluid characteristics demonstrate that a sufficient and steady amount of gas is not available to operate a separator. In instances where flowback fluid deviates from expected offset well performance such that separation of gas is practical, the operator should stop flowback (in initial flowback stage) and restart the well completion operation in separation flowback stage after separation equipment is installed.

API recommends the following clarification be added to §60.5375a(a)(1)(i):

(i) During the initial flowback stage, route the flowback into one or more well completion vessels or storage vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the initial flowback stage is not subject to control under this section. A separator is not required to be located onsite during the initial flowback stage. Once conditions allow for separation, then the operate must immediately stop the well completion operation, install a separator, and restart the well completion operation in the separation flowback stage.

22.2.6 API Agrees That The Lack Of A Flow Line/Gathering System Meets The Criteria Of Technical Infeasibility In 60.5375a(1)(Ii).

EPA states in the preamble on page 56631:

> *"There may be cases in which, for reason(s) not within an operator's control, the well is completed and flowback occurs without a suitable flow line available. We are aware that this situation may be more common for wells that are primarily drilled to produce oil. In those instances, § 60.5375(a)(3) requires the combustion of the gas unless combustion poses an unsafe condition as described above."*

Before natural gas production can be sent to natural gas gathering line, all of following must be done:

A natural gas gathering line/system must be permitted, installed and operational in the area. Permits are required for right-of-way, installation, compressor site air quality, etc. for the natural gas gathering line/system before it is installed, which take much longer than getting a permit to drill a well. Designing and installing a natural gas gathering system (including pipelines, compression, gas plant to send the gas to, etc) takes considerable time and money. Furthermore, designing and installing a gas gathering line depends on having enough natural gas production to justify the exceptional cost and burden for the gas gathering system.

A contractual right to flow into the gas gathering system must be agreed to with the company that owns the gathering line. In most cases the company owning the well is different from the company that owns the gathering system. Therefore, contracts must be put in place to allow for flow to the gathering system. The company owning the gas gathering system must determine if the pipeline has the capacity to accept the additional well or wells being added.

Necessary permits and right of way must be obtained for the pipeline from the well site to the natural gas gathering system. Permits and right-of-way are required for installation of the pipeline to connect to the natural gas gathering system. Sometimes obtaining the necessary right-of-way can be difficult and may require a court order.

The natural gas must meet the specifications of the natural gas gathering line. Contracts with the gathering company include specifications for entering the gas gathering line including concentrations of inert gases such as carbon dioxide or nitrogen, and hydrogen sulfide. Carbon dioxide and nitrogen are often used to energize well stimulations to assist with flowback and cleanup. The carbon dioxide and nitrogen flowback and cannot be routed to the pipeline because they make the gas not salable. The natural gas gathering system operator ultimately controls when an operator can send gas to sales.

There must be adequate reservoir pressure to flow into the natural gas gathering line to clean up the well and not choke it. When each stage of a stimulation program is initially completed, the pressure of the gas may not be high enough to overcome pipeline pressure and maintain adequate velocity to clean-up the well and reservoir. Any time this occurs, the well must be flared or vented until enough flowing pressure is available to send gas to the sales pipeline. This allows clean-up of the well bore and is critical to minimize the potential for formation damage. It is possible that sensitive zones can lose productivity due to increased clean-up time required if back pressure is added to the well because of the line pressures. Once a fracture stimulation is pumped, flowback and cleanup must proceed regardless of sufficient pressure to enable sales or severe and permanent reservoir damage is likely. Adding compression to overcome line pressure on low energy wells has been tried several times and found to be not feasible for technical reasons. Furthermore it adds additional emissions for engines to power the compressors while greatly increasing the cost.

The natural gas gathering line must be operational at the time of the completion. Natural gas gathering lines can be down for a multitude of reasons including but not limited to compressor maintenance or repair, line maintenance, line inspection, the gas plant being shut down, etc.

A gas gathering system with sufficient capacity must be in place. Gas that is produced from an oil well but can't be sold is known as "stranded" gas. It's stranded because the pipeline infrastructure needed to gather and transport the gas for processing is not available. Unlike gas fields where infrastructure may be unavailable in limited situations such as exploration, delineation, or some leasehold wells, gas gathering infrastructure can be unavailable for oil wells across an entire field or area. Lack of available infrastructure occurs for various reasons. For instance, insufficient associated gas production volumes may make it uneconomic to gather, process, and sell the produced gas. Or, economic gas gathering infrastructure construction may lag behind the start of new well production, as currently occurs in the Bakken oil shale formation of the Williston Basin in North Dakota. During flowback and continuing into production, stranded gas from high pressure wells such as those in the Bakken is flared for both reasons of safety and VOC emissions reduction.

While it's imperative that a gas gathering system must be available for a REC, the gathering system must also have the capacity to collect the volume of gas produced during a REC at a flow rate sufficient to clean out the well. Gas gathering systems are designed to accommodate the maximum anticipated flow rate and pressures during the production phase of wells, not necessarily the flowback phase. While this could also be a potential issue for certain gas wells, it's a known issue in the Bakken oil shale where limited gas gathering infrastructure exists. Flowing wellhead pressures are high (e.g., 4000 psi), and gas volume during initial flowback can spike at a rate many times higher than the flow rate when the well is turned over to production.

Where gathering systems exist, sending all the initial gas volume from flowback through the gathering line without properly choking the flow to prevent exceeding the gathering line capacity may cause an upset somewhere downstream because of over pressuring the system. Any major upset has the potential to result in a serious safety and/or environmental incident. Choking the flowback to meet gas gathering capacity can cause poor flowback velocity which inhibits proper cleanout of the well. Consequently, a partial REC might be feasible as some of the flowback gas may be able to be sent to sales, but remaining gas would need to be flared so as to not overpressure or exceed the capacity of the gathering system.

Furthermore, there are many reasons to complete a well and flowback without a natural gas gathering line or production equipment in place including but not limited to:

- **Avoiding lease jeopardy by establishing production in paying quantities**. Mineral leases contain expiration clauses tied to specific milestones to encourage the development of a lease hold in a timely fashion. One of the typical milestones is performance of a well completion. If the date is missed, the lease expires, causing the rights owner not only to lose the cost of the lease, but the investment in assessing the lease and preparing to drill it. It is common for operators in a low-price natural gas environment to drill and complete a well prior to acquiring surface equipment or contracting for gathering system space. Delays due to unavailability of REC equipment create an additional risk that the operator could fail to live up to steps in the contract and negate the contract causing the operator to lose their rights to the minerals.

- **Not knowing the composition of gas in advance limits the ability to design the production equipment or pipeline.** In some areas, the production equipment and pipeline are not installed until the composition of the gas is known in order to design the equipment to handle the gas and condensate, particularly for sour gas fields where the level of H2S is critical for the design requirements. This is particularly significant in areas where the reservoir and properties are not well known and delineated.
- **The surface rights must be obtained for installing production equipment.** In many cases the owners of the mineral rights are different from the surface rights; therefore, surface rights must be obtained for construction of a pad to drill a well and subsequently install the production equipment. These surface rights are size/area limited and in many cases not sufficient to have in place both the completions equipment and the production equipment at the same time so companies wait to install the production equipment until after the drilling and completions equipment are gone. This also limits the "footprint" of surface disturbance to the area.

22.3 Distance To The Gathering Line Is Not A Valid Criterion On Which To Base Requirements For Gas Recovery.

Sufficient natural gas production in the area is required to justify the cost and burden for permitting, designing, and building the natural gas gathering system. Before gas can be routed to a gas gathering line, all the following must be done:

- A natural gas gathering line system must be permitted, installed and operational in the area a reasonable distance from the well.
- A contractual right to flow into the gas gathering system with the company that owns the gathering line must be in place.
- The necessary permits and right-of-way for the pipeline from the well site to the natural gas gathering system must be obtained.
- The natural gas must meet the specifications of the natural gas gathering line.
- There must be adequate reservoir pressure to flow into the natural gas gathering line to clean up the well against the pipeline pressure without lowering the flow and velocity to the point where the well will not adequately clean-up.

Furthermore in the preamble EPA has solicited comment on criteria that could help clarify availability of gathering lines (FR 56634), and specifically mentions *"that some states require collection of gas if a gathering line is present within a specific distance from the well. For example, Montana allows gas from wells to be flared only in cases where the well is farther than one-half mile from a gas pipeline.*

EPA may have misinterpreted the cited Montana regulation: "(2) The owner or operator of an oil and natural gas well facility shall operate the air pollution control equipment and comply with the air pollution control practices required in (1) from the initial well completion date for the facility until the department decision on the permit application is final. (Emphasis added)

Therefore, this control equipment requirement applies from the "initial well completion date for the facility" until a decision is made on a permit application. The term "initial well completion date for the facility" is not defined in the section referenced by EPA. However, if you look at the history of this regulation (prior regulation 75-2-211), the term means:

"For purposes of this section, the initial well completion date for an oil or gas well facility is:

(i) For an oil or gas well facility producing oil, the date when the first oil is produced through wellhead equipment into lease tanks from the ultimate producing interval after casing has been run: and

(ii) For an oil or gas well facility producing gas, the date when the oil or gas well facility is capable of producing gas through wellhead equipment from the ultimate producing interval after casing has been run.

Therefore, the Montana regulation appears to only apply from the date a well is producing oil and natural gas to lease sales (what EPA describes as the production phase) and not during flowback from hydraulically fractured completions.

In addition to the issues with gathering line permitting and availability outlined in detail above, there are many situations that would disallow legal access to a gathering system even if an existing gas pipeline was less than one half mile from a well including but not limited if the land between the well and pipeline is designated wetland, the presence of endangered species has been identified, landowner disputes, and archeological issues.

22.4 Impacts, Emissions, Costs

Most of the cost to flare flowback gases is for rental of the separator equipment, mileage, labor to install and remove equipment, and additional personnel to operate the specialty equipment. In public comments on the EPA White Paper on Hydraulically Fractured Oil Wells, IPANM members estimated the cost for flaring oil well completions as up to $10,000 per day. API agrees that this is a more reasonable typical cost to rent, transport, install, operate and remove separator and flare equipment. In addition, flowback can range from one day to more than 30 days, with 3 to 7 days being most typical.

22.5 REC Equipment Availability

API has not had enough time to determine if there is adequate REC equipment available to handle the new requirements on hydraulically fractured oil wells. However, in the current low oil price environment, many operators are drilling oil wells, but delaying well completions until a later date. API estimates that by the time Subpart OOOOa is finalized, there could be a backlog of up to 10,000 drilled oil wells waiting to be completed that could overwhelm the REC equipment market during an oil price recovery.[25] Therefore, API recommends that hydraulically fractured oil wells that have been drilled, but not completed by the effective date of the final rule, should be exempt from the requirements to conduct an REC. In reality, companies will likely conduct an REC if equipment is available and if feasible, but this exemption would allow the requirement for REC for hydraulically fractured oil wells to begin without a very large backlog of drilled wells that have not yet been completed. Otherwise, there could be many instances where a company is not able to find REC equipment and would be out of compliance. This will

[25] Doan, Lynn and Dan Murtaugh. (2015, April 23 U.S. Shale Fracklog Triples as Drillers Keep Oil from Market. *Bloomberg Business*. Retrieved from < http://www.bloomberg.com/news/articles/2015-04-23/u-s-shale-fracklog-triples-as-drillers-keep-oil-out-of-market-i8u004xl>

give REC equipment manufacturers and the oil and natural gas industry more certainty in understanding additional REC equipment needs in the future.

22.6 Reporting and Recordkeeping

22.6.1 EPA Should Not Require Tracking Attempts To Connect To A Separator For Flowback That Never Leaves The Initial Flowback Stage.

As described in Section 22.2.6, API requests that EPA clarify the recordkeeping requirements outlined in §60.5420a(c)(1)(iii)(A) for tracking attempts to connect to a separator as only being applicable during the separation flowback stage (after initial flowback, they are hooked up to a production system). For well completion operations that remain in the initial flowback stage, a separator is not required and, therefore tracking attempts to connect to one is not applicable.

23.0 RECIPROCATING COMPRESSORS

23.1 Emission Limits/Control Requirements

23.1.1 Negative Pressure Requirement On Routing Reciprocating Rod Packing Emissions Back To Process Is Flawed And Should Be Amended Relative To Operating Pressure – Not Relative To Atmosphere.

The requirements in §60.5385(a)(3) and §60.5385a(a)(3) that require the collection of emissions from the rod packing under negative pressure is technically flawed where EPA states the following:

> *"Collect the emissions from the rod packing using a rod packing emissions collection system which operates under negative pressure and route the rod packing emissions to a process through a closed vent system..."*

Operating a crankcase collection system under a negative pressure (vacuum) leads to significant safety issues with the possibility of oxygen being introduced into the system.

Therefore, API recommends the language be amended in in §60.5385(a)(3) and §60.5385a(a)(3) to the following:

> "Collect the emissions from the rod packing using a rod packing emissions collection system ~~which operates under negative pressure~~ and route the rod packing emissions to a process through a closed vent system..."

24.0 PNEUMATIC PUMPS

24.1 General Discussion

API appreciates EPA's efforts to simplify control requirements for pneumatic pumps as well as EPA's recognition that there are limited scenarios for which control of pneumatic pumps will be cost effective. However, from review of the preamble of the rule proposal and the Technical Support Document, it is clear that EPA did not appreciate some key technical issues as well as some key costs that would be incurred if the rule were finalized as proposed.

Each of these points is expanded upon in this section, but API recommends that the following exemptions should be added to the proposed requirements for pneumatic pumps:

- Technical Feasibility – If it is not technically feasible to connect a pump to an existing on site control device, there should be an exemption under the rule.
- Small or limited use emission pumps (< 53 thousand scf per year emission rate, which is equivalent to a continuous 6 SCFH emission rate) rate or any pump operating less than 90 days per year).

Additionally, EPA has proposed overly burdensome and costly testing and monitoring requirements for control systems used to control pumps. If control requirements are retained for any types of pneumatic pumps, the rule should eliminate testing, monitoring, and recordkeeping requirements for the control device that are triggered solely due to the connection of a pneumatic pump exhaust to the closed vent system or control device. Alternatively, EPA should only require control of pumps when an existing Subpart OOOO/OOOOa control device which is already subject to the same requirements as in the proposed rule is present.

Finally, for many technical reasons, API believes it is important that EPA should clarify in the rule that the presence of a heater or boiler should not be considered to be equivalent to presence of control device. This is discussed in detail in Section 13.0of these comments.

API also appreciates EPA's preamble discussion that recognizes the limitations of solar powered pumps, the typical unavailability of electricity at well sites and other remote sites, and the fact that gas-assist lean-glycol recirculation pumps on glycol dehydration units are not pneumatic pumps. API agrees with EPA's approach of defining the affected source as only pumps using natural gas as the pneumatic power source and located at a site with an existing control device. API also agrees with EPA's approach of only requiring control of new, modified or reconstructed pneumatic pumps on sites with existing control devices (combustion control or vapor recovery). However, API has several important issues with the details of the regulation as proposed.

- EPA inappropriately requires an existing control device/system to meet the closed-vent-system, performance testing, monitoring, and recordkeeping requirements of Subpart OOOOa if a new, modified, or reconstructed pneumatic pump is routed to it. This is exacerbated by the proposal to require the same measures as for wet-seal centrifugal compressor affected source control devices.
- API believes the capital cost estimate EPA made is low and that several significant cost items are left out of the cost analysis.
- API believes the estimated emissions per pump for diaphragm type pumps is overestimated and the equal proportional split between piston type chemical pumps and diaphragm pumps is incorrect. Due to the limited time available for comment, API did not have time survey members adequately, but there are many more piston pumps installed than diaphragm pumps.
- Because the cost is underestimated and the emissions overestimated, the control actions required by the regulation are not cost effective in many instances.
- EPA failed to recognize important design and process factors that could render routing a pneumatic pump to an existing control device technically infeasible or unsafe.
- Some details of the regulatory language are unclear or not defined fully.

Each of these issues is discussed in more detail in the following sections.

24.2 Control Device And Closed Vent System Requirements

As written, control devices not subject to Subpart OOOO or OOOOa would be required to be used to control emissions from pneumatic pumps. It is not clear if this was EPA's intent in writing the rule. From the lack of consideration for performance requirements, performance testing, closed vent system monitoring, recordkeeping, and reporting compliance costs in the economic analysis, it appears that EPA did not intend for control devices not subject to Subpart OOOO of OOOOa to be pulled into the monitoring, reporting, and recordkeeping requirements under Subpart OOOOa. If EPA maintains a requirement to route higher emitting pneumatic pumps to existing control devices, this should not trigger the performance specifications, performance testing, monitoring, closed vent system monitoring, recordkeeping, and reporting requirements for the control device if it is not already subject to regulation under Subpart OOOO. This change from the proposed approach would address one of the two critical cost elements ignored by EPA when assessing the cost of control; specifically, the costs of testing, monitoring, reporting, and recordkeeping requirements.

EPA should also provide for routing of pump exhaust from glycol heat medium pumps (typically diaphragm type pumps) to a controlled tank or knock-out drum prior to the control device to provide for buffering the intermittent flow when the pump exhaust stroke occurs. This would provide for more stable flow to the control device and piping system and simplify connecting a pneumatic pump exhaust to an existing control system.

The proposed rule unnecessarily and inappropriately requires existing control devices and closed vent systems to comply with the full suite of requirements identical to those specified for control devices and systems on centrifugal compressor affected facilities degassing tank vents if a new, modified, or reconstructed pneumatic pump affected source is routed to the control device. EPA failed to recognize that the majority of the existing control devices and closed vent systems installed on sites where pneumatic pumps are likely to be used will not already be subject to Subpart OOOO requirements let alone those for centrifugal compressor affected facilities. Since centrifugal compressors are rarely used in the production segment and new, modified, or reconstructed centrifugal compressors in the gathering & collection, processing, and transportation & storage segments are almost certainly dry seal equipped, the probability is near zero that an existing control device on well sites or remote facilities would already be subject to the centrifugal compressor affected source requirements for closed vent systems and control devices. Most already installed or newly installed control devices/systems and closed vent systems will predate the requirements of Subpart OOOO or be installed pursuant to State regulations or enforceable permit conditions that limit emissions below the thresholds for applicability of Subpart OOOO. Even where an existing control device and closed vent system has applicable requirements under Subpart OOOO, these are almost certainly those requirements for control devices and closed vent systems installed on storage tank affected sources rather than centrifugal compressor affected sources and thus would have new requirements under the proposed rule. This could subject an individual control device and closed vent system to a dual set of requirements if the proposed rule is finalized as proposed. Note that this discussion focuses on enclosed combustion control devices as sites with VRU's are likely to have electricity and hence no pneumatic pump affected sources.

By requiring existing closed vent systems and control devices to comply with the specified requirements listed in §60.5410a, §60.5411a, §60.5412a, §60.5413a, §60.5415a, §60.5416a, and §60.5417a the proposed rule retroactively applies unnecessary, burdensome, and costly requirements to existing control devices and systems that were not designed, installed, or intended to comply with these requirements. Note also that none of the additional costs are included in EPA's analysis of the reasonableness of controlling pneumatic pump affected sources and the additional costs are likely to render such control not reasonable - cost analysis details are presented in a separate section of these comments.

- §60.5411a & §60.5416a: An existing closed vent system may not be designed or constructed to meet the standard of "no detectable emissions" specified in 6§0.5411a and detailed in §60.5416a. Again, this may force retrofit or replacement of the existing piping system to enable meeting the "no detectable emissions" requirement.

- §60.513a: Existing control devices and the piping to them are not likely to have the necessary ports installed to enable performance testing as specified in 60.5413a and would have to be taken offline in order to retrofit them if retrofit is even possible.
- §60.5415 & §60.5417: Existing control devices are unlikely to have all of the monitoring instruments and capabilities required for continuous compliance demonstration as required in §60.5415a and these would have to be retrofitted to the control device. Again, retrofit may not be possible which would leave an operator with no avenue to comply without installing a new control device which EPA already found to be not reasonable from a control cost standpoint. Additionally, the data monitoring, logging and averaging required under §60.5417a would require either installation of an entirely new monitoring system or tying the monitoring devices into an existing automation system programmable logic controller (PLC) which may not have the number of input ports necessary nor have the memory and computing power necessary. Due to the typical lack of electrical power, the installation of a monitoring system would also require installation of a solar power system with the necessary power to operate the system and the necessary battery back-up to assure adequate data recovery.

Requiring control devices and covered vent systems, where a pneumatic pump affected source is routed to them, to comply with the performance testing, continuous monitoring, and associated requirements of the proposed rule is not necessary. The exhaust from a pneumatic pump affected source is the same natural gas used for the pilot flame in a combustion control device and as fuel for a boiler or heater. It is not difficult to combust and should not require the same rigor of demonstration for more difficult to combust compounds. In general, the low molecular weight straight chain aliphatic hydrocarbons that characterize the natural gas industry, including associated gas, are easy to combust.

To address the issues regarding retroactive application of the requirements in §60.5410a, §60.5411a, §60.5412a, §60.5413a, §60.5415a, §60.5416a, and §60.5417a to existing control devices and closed vent systems not already subject to the requirements proposed, API recommends EPA take one of the following approaches.

Maintain the current definition of pneumatic pump affected source and require that the existing control device and closed vent system comply with whatever existing requirements for testing, monitoring, and reporting exist for the particular site/control device and closed vent system.

-or-Redefine the pneumatic pump affected source as only those new, modified, or reconstructed natural gas powered pneumatic pumps installed at a site with an existing control device that is already subject to the requirements contained in §60.5410a, §60.5411a, §60.5412a, §60.5413a, §60.5415a, §60.5416a, and §60.5417a proposed in the rule.

To assure the integrity of the newly installed piping routing a new, modified, or reconstructed pneumatic pump affected source to an existing closed vent system or directly to the control device EPA could require an annual leak inspection with an Optical Gas Imaging camera for the newly installed piping to an existing control device or closed vent system.

24.3 Impacts, Emissions, Costs

24.3.1 EPA Underestimated The Cost Of The Proposed Control Strategy Which Renders It Not Cost Effective In Many Situations.

In the cost analysis for the proposed control strategy for pneumatic pumps, EPA incorrectly only listed a one-time capital cost impact of $2,000 for the design and installation of piping to route vapors from the exhaust of a pneumatic pump to an existing control device. This value was based upon Natural Gas Star program data.[26] Using a 7% interest rate, EPA estimated the annualized cost of controlling a pneumatic pump at $285/year.

This value is too low and does not include significant cost items required by the rule. As an example, EPA assumed a cost of $23,252 for tying a wet-seal centrifugal compressor seal-oil degassing tank into an existing control device. The low pressure nature of both pneumatic pump exhaust and a seal-oil degassing tank are similar. Unfortunately, the Technical Support Document for Subpart OOOOa (TSD) discussion of pneumatic pump control and seal-oil degassing control is not detailed enough to understand the difference in EPA's cost estimates.

API believes the average capital cost (inclusive of engineering) that would be incurred for design evaluation, designing, and construction of the piping to tie a pneumatic pump into an existing control device/system would be closer to $5,800 and would vary considerably from site to site

Following are the details of API's initial capital cost estimate.

- Collecting the site specific information on an existing control device/system and performing an engineering evaluation of the ability to safely and technically add pump exhaust gas to the control device/system. Eight (8) hours of engineering time at $185 per hour = $1480.
- Evaluating the specific pump's ability to tolerate the exhaust backpressure necessary to route to the existing control device/system; designing the piping necessary to route a pump exhaust to the control device/system; specifying materials, connection points, and connection types for routing a pump exhaust to the control device/system; and writing a work-order and procedure for connecting. 8 hours of engineering time at $185 per hour = $1480.
- Ordering and collecting materials for installing the piping, commissioning a contractor to perform the work, and overseeing the work. Six (6) hours of construction specialist time at $140 per hour = $840.
- Travel to the site, installation of the piping for tie-in, verification of the proper functioning of the tie-in and travel from the site. One day of a contract construction crew time at $2,000 per day = $2,000.
- Utilizing EPA's assumed 7% interest rate, this equates to an annualized initial capital cost of $826 rather than EPA's value of $285.

In addition to underestimating the capital costs of routing the emissions to a control device, EPA did not consider other significant initial and reoccurring costs that would be incurred. The proposed rule requires an existing control device and closed vent system with a pneumatic pump routed to them to comply with the same performance testing, closed vent system, continuous monitoring, and recordkeeping and

[26] http://www.epa.gov/gasstar/documents/pipeglycoldehydratortovru.pdf

reporting requirements applicable to closed vent systems and control devices specified for centrifugal compressor affected facilities. The majority of the existing control devices and closed vent systems installed on sites where pneumatic pumps are likely to be used will not already be subject to Subpart OOOO or Subpart OOOOa requirements let alone those for centrifugal compressor affected facilities. The probability is near zero that an existing control device subject to the centrifugal compressor affected source requirements for closed vent systems and control devices will be on a site where a pneumatic pump source is located.

Most already installed or newly installed control devices/systems and closed vent systems will predate the requirements of Subpart OOOO or Subpart OOOOa be installed pursuant to State regulations or enforceable permit conditions that limit emissions below the thresholds for applicability of Subpart OOOO or Subpart OOOOa. As such, costs not included in EPA's analysis are:

- The costs for an initial M21 demonstration that the closed vent system, at a site not already subject to the requirements under Subpart OOOO, is operating with no detectable emissions.
- The costs for initial and periodic performance testing of a control device that is not already subject to the required performance testing.
- The costs for monthly smoke inspections, including travel to and from the site for a trained visual smoke inspector.
- The costs for design, installation and maintenance of a parametric monitoring system.
- The recordkeeping and reporting cost.

The table below provides a more complete estimate of the costs associated with implementing the proposed rule requirements for pneumatic pumps. This table reflects the true cost of compliance with the rule, including potential source testing, the need to install monitoring equipment, and the costs of conducting recurring inspection and equipment maintenance that would all be triggered by the proposed compliance requirements. Note that none of the performance testing exemptions listed in §60.5413a (a) 1 - 7 are considered. It should be noted that:

- Heaters with a design capacity of 44 MW (150 million BTU/hr) will not occur in the types of sites where pneumatic pump affected sources will be used
- Heaters used at well sites and other remote sites are likely to be seasonally used, or have intermittent firing dependent on heat demand and hence will not be able to accept the exhaust gas from a pneumatic pump as part or all of the fuel at all times
- As discussed previously, an existing control device is almost certainly not already subject to the performance testing requirements of §60.5413 and hence not manufacture certified.
- Hazardous waste incinerators or hazardous waste fueled heaters will not occur at the type of sites where pneumatic pump affected sources will be used.

Table 24-1 Pneumatic Pump Control Cost Table

Cost Item	*Initial Cost*	*Annualized Cost*
Capital Costs (including engineering)	$5,800	$826
Option 1 Combustor Testing (repeat each 5 years)	$6,000	$1,200
Option 2 Process Heater Testing (repeat each 5 years)	$6,000	$1,200
Annual M21 & Visual CVS Inspection *(Contractor or Trained Technician - ½ day with vehicle)*	$600	$600
Monthly 15 min Smoke Check (trained operator inspection - $160/month)		$1,800
Flow Monitor, Thermal Dispersion Meter	$5,000	$712
CPMS - install measurement device and solar panel	$9,000	$1,282
CPMS - Annual Maintenance (contractor 1/2 day)		$600
Annual CPMS Auditing (trained instrument technician complete with equipment and vehicle - 1/2 day)		$600
Scenario		*Annualized Total*
Sites with Affected Pneumatic Pumps & Combustor field performance test		$6,908
Sites with Manufacturer Certified Combustor (no performance test)		$6,420
Sites with Affected Pneumatic Pumps (& Process Heater performance test)		$6,908
Sites with existing Subpart OOOO or OOOOa affected storage tank with control device		$3,308
Sites with existing Subpart OOOO or OOOOa affected compressor with control device		$826

Table 24-2 Retrofit Costs for Control Devices

Cost Item	*Initial Cost*	*Annualized Cost*
Retrofit control device with new or relocated ports to enable performance testing per 60.5413a. (likely to occur)	$3,000	$427
Retrofit closed vent system to meet "no detectable emission" requirement per §60.5416a (less likely to occur)	$3,000	$427

Table 24-3 Average Pneumatic Pump Emission Rate (Reproduced from TSD)

	Tons/year Methane	Tons/year VOC
Piston Pump	0.38	0.11
Diaphragm Pump	3.46	0.96

Combining the complete estimate of actual costs for routing a pneumatic pump affected source to an existing control device with the emission estimates for piston pumps and diaphragm pumps from the Technical Support Document (repeated in proposed rule preamble) yields the following tables of control cost per ton for methane, VOC, and from a multipollutant approach consistent with that used by EPA for the proposed rule.

Table 24-4 Piston Pump Control Cost Effectiveness (assuming 8760 hours of annual pump operation)

	Scenario	**Single Pollutant Approach**		**Multipollutant Approach**	
		Methane Only	**VOC Only**	**Methane**	**VOC**
Production Piston Pumps	*Sites with Affected Pneumatic Pumps & Combustor field performance test*[1]	$18,178	$62,797	$9,089	$31,399
	Sites with Manufacturer Certified Combustor (no performance test)	$16,894	$58,362	$8,447	$29,181
	Sites with Affected Pneumatic Pumps (& Process Heater performance test)[1]	$18,178	$62,797	$9,089	$31,399
	Sites with existing Subpart OOOO or OOOOa affected storage tank with control device	$8,705	$30,070	$4,352	$15,035
	Sites with existing Subpart OOOO or OOOOa affected compressor with control device	$2,174	$7,509	$1,087	$3,755

[1]Note – These costs do not include the additional costs of retrofitting the control device (sampling ports, etc.) and the closed vent system per Table 24-2. Inclusion of these costs would only further increase the cost effectiveness ratios. It also does not include the cost of recordkeeping and reporting required by the rule.

Table 24-5 Diaphragm Pump Control Cost Effectiveness (assuming 8760 hours of annual pump operation)

		Single Pollutant Approach		Multipollutant Approach	
	Scenario	**Methane Only**	**VOC Only**	**Methane**	**VOC**
Production Diaphragm Pump	*Sites with Affected Pneumatic Pumps & Combustor field performance test*[1]	$1,996	$7,196	$998	$3,598
	Sites with Manufacturer Certified Combustor (no performance test)	$1,855	$6,687	$928	$3,344
	Sites with Affected Pneumatic Pumps (& Process Heater performance test)[1]	$1,996	$7,196	$998	$3,598
	Sites with existing Subpart OOOO or OOOOa affected storage tank with control device	$956	$3,446	$478	$1,723
	Sites with existing Subpart OOOO or OOOOa affected compressor with control device	$239	$860	$119	$430

[1.] Note – These costs do not include the additional costs of retrofitting the control device (sampling ports, etc.) and the closed vent system per Table 24-2. Inclusion of these costs would only further increase the cost effectiveness ratios. It also does not include the cost of recordkeeping and reporting required by the rule.

While EPA does not establish a bright line that separates what they consider to be reasonable and unreasonable with regard cost effectiveness, the proposal provides indications of levels that EPA clearly considers to be unreasonable. On page 56636 of the September 18, 2015 Federal Register notice proposal, EPA indicates: "In a previous NSPS rulemaking [72 FR 64864 (November 16, 2007)], **we had concluded that a VOC control option was not cost-effective at a cost of $5,700 per ton**." While EPA does not make an affirmation that is as clear-cut for methane, EPA's decisions establish a precedent. For quarterly OGI monitoring for well sites, EPA estimated the cost effectiveness levels shown in Table 24-6. For this option, EPA determined that "we find that the cost of monitoring/repair based on quarterly monitoring at well sites using OGI is not cost-effective for reducing VOC and methane emissions under either approach." (80 FR 53363). Therefore, since EPA rejected this alternative with a cost effectiveness of $1,761 per ton of methane reduced, this clearly establishes that EPA believes that $1,761/ton of methane is unreasonable.

Table 24-6 EPA's Estimated Cost Effectiveness with Savings ($/ton) for Quarterly OGI Monitoring at Well Sites.

Single Pollutant[a]		Multipollutant[b]	
Methane	VOC	Methane	VOC
$3,521	$12,668	$1,761	$6,334

[a]Table 5-16 of the Background Technical Support Document.

[b]Table 5-17 of the Background Technical Support Document.

As illustrated above in Table 24-4, for piston pumps, the control costs for the only likely scenarios of an existing control device and closed vent system having no performance testing or monitoring requirements under Subpart OOOO or an existing control device and closed vent system being subject to only the Storage Tank performance testing and monitoring requirements under Subpart OOOO exceed the reasonable cost of control per ton whether viewed from a single pollutant standpoint or from a multipollutant standpoint. The only reasonable control costs found were for an existing control device and closed vent system that is already subject to the performance testing and monitoring requirements specified in the proposed rule and this was only cost effective under the multi-pollutant approach. As explained in more detail earlier in these comments, the probability of this occurring is near zero.

For diaphragm pumps, the cost effectiveness values shown above are lower due to the higher emissions. However, as discussed further in 0, diaphragm pumps are generally used for heat tracing and as such are not used everywhere and, when they are used do not operate year round. Using a more realistic estimate of 4 months of operation per year, the emissions from these pumps are actually 1/3rd the level assumed by EPA. The table below reflects the cost effectiveness of controlling diaphragm pumps after accounting for their non-year round operation.

Table 24-7 Diaphragm Pump Control Cost Effectiveness (assuming 4 months of annual pump operation)

		Single Pollutant Approach		Multipollutant Approach	
	Scenario	**Methane Only**	**VOC Only**	**Methane**	**VOC**
Production Diaphragm Pump	***Sites with Affected Pneumatic Pumps & Combustor field performance test[1]***	$5,989	$21,587	$2,995	$10,793
	Sites with Manufacturer Certified Combustor (no performance test)	$5,566	$20,062	$2,783	$10,031
	Sites with Affected Pneumatic Pumps (& Process Heater performance test)[1]	$5,989	$21,587	$2,995	$10,793
	Sites with existing Subpart OOOO or OOOOa affected storage tank with control device	$2,868	$10,377	$1,434	$5,198
	Sites with existing Subpart OOOO or OOOOa affected compressor with control device	$716	$2,581	$358	$1,291

1. Note – These costs do not include the additional costs of retrofitting the control device (sampling ports, etc.) and the closed vent system per Table 24-2 Retrofit Costs for Control Devices. Inclusion of these costs would only further increase the cost effectiveness ratios.

After accounting for the non-year round operation of pneumatic pumps, it is again the case that the only clearly reasonable control costs found were for an existing control device and closed vent system that is already subject to the performance testing and monitoring requirements specified in the proposed rule. As explained in more detail earlier in these comments, the probability of this occurring is near zero. The case of control with a device that is subject to the storage vessel control requirements under Subpart OOOO result in marginal cost effectiveness, but only under the multipollutant scenario.

This illustrates the need for EPA to revise the proposed rule's approach to performance testing and monitoring for control devices and closed vent systems used for pneumatic pump affected sources as previously explained earlier in these comments.

Note: The above conclusions are drawn even without accounting for the additional costs for recordkeeping and reporting, which were also not considered by EPA when evaluating the cost effectiveness of pump control options.

24.3.2 EPA Did Not Consider Or Provide For Instances Where Routing A Pneumatic Pump Affected Source To An Existing Control Device Is Not Technically Feasible Or Where The Control Device Belongs To Another Party

Whether considering a VRU, flare, enclosed combustion device, or any other control technique, control devices are designed for a specific set of conditions with a number of key assumptions. For example, a flare header might be designed to allow enough flow to permit two pressure safety valves (PSV) to open simultaneously without creating so much back pressure as to take either PSV out of critical flow. The design is sensitive to other flow streams in the pipe and putting a pump exhaust into that header could result in too much backpressure for the safety devices to function as intended. Conversely, but equally important, a pneumatic pump is chosen for a specific backpressure and the backpressure imposed by a PSV could stop the pump from functioning at a critical moment, exacerbating the already unstable situation that resulted in the opening of the PSVs.

Additionally, enclosed combustion devices are designed for a maximum BTU load and may not be able to accommodate the exhaust gas from a pneumatic pump affected source without replacing the control device.

The design process for VRUs are even more sensitive to changes than other control devices. The VRU equipment is designed to recover vapors and raise their pressure enough to be useful, is expensive, and has a limited range of possible flow rates. Adding vapor loads to a VRU must be carefully evaluated on a case-by-case basis.

In some instances an existing control device on a particular site may be owned and operated by a third party, such as a control device owned and operated by a gathering and collection system operator with a glycol dehydration unit on a well site. In these instances, the well site operator does not have the right to route a pneumatic pump affected source exhaust to the control device.

EPA should provide exclusion in the rule such that routing a pneumatic pump affected source to an existing control device or closed vent system is not required if it is not technically feasible or if the control device is not owned and operated by the site operator. Proposed updated rule language is included in 24.4.1.

If needed, EPA could provide provisions in the rule for an operator to make an engineering determination that an existing control device cannot technically handle the additional gas from a pneumatic pump affected source exhaust, document this determination, and make such a determination available for inspection by EPA or other competent authority.

24.3.3 EPA Did Not Consider How This Rule And Its Requirements To Route Pneumatic Pumps To Control Devices Can Potentially Trigger Permitting Requirements.

Under the proposed Subpart OOOOa, EPA is requiring that the exhaust from pneumatic pumps be controlled by control devices if those devices are present on site.

EPA's analysis of the proposed approach to pneumatic pumps has ignored the fact that such an action may require amending the air permit for a facility simply due to a replacement in kind of a pump under Subpart OOOOa. Many state new source review (NSR) programs require permits, simply because an NSPS or NESHAP requirement applies, even if a permit is not otherwise required. Additionally, the exact requirements will vary based on the local permitting requirements, but in many cases, the act of tying a new stream into a combustion control device will result in a change in emissions from a site due to the rerouting, which can trigger permitting. Local permitting requirements are very sensitive to the reality that control devices are subtle and complex engineering structures that have very real physical limits. As discussed above, EPA's proposal for natural gas pneumatic pumps under Subpart OOOOa seems to ignore these physical realities.

EPA has not accounted for any time or expense associated with this permitting action, nor have they considered any of the additional burden on permitting authorities. These impacts should be quantified and considered prior to finalizing Subpart OOOOa regulatory text that may trigger state permitting requirements. One alternative to this concern is to revise the affected source criteria so that a pneumatic pump would not be an affected source, if it was connected to a control device on site. This could be accomplished by revising the text of 60.5365(h)(2) as follows:

> (2) For locations other than natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven chemical/methanol pump or natural gas-driven diaphragm pump ~~for~~ which has not been connected to a control device when one is located on site.

An additional advantage of this approach is that it clearly removes the addition of monitoring and performance testing currently in the proposed rule. As discussed in Sections 24.3.1 and 24.5.2, these costs were not included in EPA's cost effectiveness analysis, nor should compliance assurance requirements from OOOOa be required for a control device that was installed for another purpose.

Note that there are additional revisions to §60.5365a(h)(2) proposed in Sections 20.0, 24.4.1, and 24.4.5 to address separate applicability issues should EPA decide to regulate pumps as proposed.

24.3.4 EPA Overstated The Emissions, And Therefore The Benefits, Of The Proposed Requirements For Pneumatic Pumps

EPA has overestimated the emissions from diaphragm pumps. As EPA notes in Section 7.1 of the TSD: "Diaphragm pumps are commonly used to circulate hot glycol or other heat-transfer fluids in tubing covered with insulation to prevent freezing in pipelines, vessels and tanks." As such, these pumps only during the winter season which represents a fraction of the year on average. Yet, EPA has assumed these pumps operate 8,760 hours per year when estimating emissions. This assumption grossly inflates the actual emissions from these sources. A more realistic estimate would be that these sources would operate 3-4 months during the course of the year and rarely more than 8 months per year. Using this more realistic estimate of hours of operation, the values in Table 7-17 change dramatically for diaphragm pumps – both in terms of emissions reduced and gas recovered by use of a VRU. Also, using diaphragm pumps to circulate heat-trace fluids is only practiced in climates with cold winters (e.g. Wyoming) and does not occur in warmer climes.

Diaphragm pumps are also used intermittently to transfer bulk fluids such as engine oil or emptying a sump. When used for these types of service they do not run for long periods, are not large emission sources and should not be subject to regulation under Subpart OOOO.

API recognizes the need for EPA to simplify analysis for assessing cost benefits for this rulemaking. EPA presents values in Table 7.2 which are based on a number of assumptions. It should be noted that the exhaust rates from pneumatic pumps are, in reality, based on assumed pump rate, a gas-supply pressure, and a pump model. All of these values vary considerably from site to site and even from pump to pump on a given site. When one reviews several manufacturer's pumps, it is readily apparent that they all have a multiplier factor for calculating required supply pressure and allowable exhaust pressure and these factors vary by over two orders of magnitude from one pump model to the next.

24.3.5 Electrical Power Is Not Available At Most Well Sites And Can Be Very Costly To Connect When It Is Available Nearby.

In the preamble, EPA requested comments on the availability of a constant, reliable source of electrical power at facilities throughout the oil and natural gas source category (FR 56625). "Electrical power" is typically taken as either grid power or locally-generated power. Generally, locally-generated power is solar power. These two power sources will be addressed separately.

Grid power is often not available in oil and natural gas producing sites due to their very remote nature. When grid power is available, it can be costly for oil and natural gas operators to establish a connection to the grid. Due to the significant cost associated with connecting to the grid, the payback on the capital costs of running grid power to wellsites to replace a pneumatic pump with an electric pump is generally too long (often hundreds of years) to be considered. Further, API member company experience is that well sites often receive low priority behind others (hospitals, schools, residences, businesses, etc.) for connection services.

That said, when grid power is available, operators likely already utilize it to the extent possible for powering and monitoring of operations. If grid power were available, it would often be effective and efficient to electrify pumps rather than converting pneumatic pumps to instrument air. The use of electric motor driven pumps is a mature technology that is widely and typically used when reliable grid supply is available. Electric motor driven pumps also tend to be more reliable and more energy efficient than pneumatic driven pumps. Conversely, installing air compressors would be more expensive and less efficient. Instrument air systems are only economically feasible at sites where the pneumatic supply gas demand is sufficient to justify the capital and operating expense of an instrument-air compressor. At single well sites and even multi-well pads this is rarely the case, and the economics of electric pumps and controls are better than the economics of installing instrument air.

While the use of electric motor driven pumps is mature, the problem is that pumps tend to require a significant power load – a load that is far better suited to grid power than solar power. While solar pumps are sometimes an option, especially for low flow chemical injection pumps with low actuation frequency, as API pointed out in prior comments on the White Paper, there are limitations to their usage. For example, the White Paper noted that larger volume capacity solar operated pumps with high discharge pressures are available. This is not a valid conclusion from API's experience or from the source cited by EPA (U.S. EPA, 2011b). Only the smallest of jobs requiring wellsite pumping are suitable for solar-powered pumps.

24.3.6 Glycol Dehydrator Circulation Pump Emissions Vary, But Are Limited By Other Existing Regulations.

In the preamble, EPA requested comments and additional information on the level of uncontrolled emissions from glycol dehydrator lean-glycol circulation pumps, how they are vented through the dehydration system, and the amount and characteristics of VOC and methane emissions from uncontrolled glycol dehydrators. (FR 56627)

API believes that the dehydrator units with the highest potential VOC and methane emissions are already being controlled as a result of 40 CFR 63 Subparts HH and HHH either to meet the MACT control requirements or to take an enforceable limit on benzene emissions for the less than 1 TPY benzene applicability exemption. The use of combustion devices to control HAP emissions from dehydrator units also reduces VOC and methane emissions.

24.4 Applicability/Definitions

24.4.1 The Rule Should Have An Exemption For Limited Use/Low Emission Pumps Such As Chemical Injection Pumps.

API believes EPA's intent to regulate pneumatic pumps that have lower emission rates than continuous low bleed pneumatic controllers is inappropriate. EPA has previously determined that continuous bleed pneumatic controller devices emitting less than 6 scf/hour did not require control and EPA continues to support that position in the Subpart OOOOa rule proposal. EPA's Technical support document shows the assumed emission rate from pneumatic piston (chemical and methanol) pumps to be 2.48 scf/hour, which is less than half the 6 scf/hr threshold for continuous bleed pneumatic controllers. The cost effectiveness of controlling such low emitting pumps is substantially above EPA's assumed $285/ton as described Section 22.3.1. Piston pumps in services with emissions below 53,000 scf/year (approximately equivalent to 6 scf/hour annualized) should be exempt due to the low volume of gas exhausted. Demonstration of emissions below this threshold should be a one-time engineering calculation for individual pumps or a class of pumps in similar service - for example chemical/methanol pumps below a pressure & volume combination which would yield exhausted volumes above the threshold.

There are also natural gas-driven pneumatic pumps, typically diaphragm pumps, which are used intermittently to transfer bulk liquids. These are generally either manually operated as needed or are triggered by a level controller. For instance, there are engine skid sump pumps, pipeline sump pumps, tank bottom pumps, flare knockout drum pumps, separator knockout drum pumps, etc. that are used to pump liquids from one place to another. These pumps do not run continuously or even seasonally for long periods, but only run periodically as needed. Thus, these pumps do not exhaust large volumes of gas in the aggregate. For this reason, there should be an annual venting limit and an exemption for intermittently operated pumps.

EPA should provide an exemption under the rule for any pump emitting at a rate less than the rate of a continuous low bleed pneumatic controller. Specifically, any pneumatic pump which emits less than 53,000 scf/year (i.e. 6 scf/hour for an entire year) should be exempted. This would provide a reasonable exemption for intermittent use pneumatic pumps which do not have large aggregate emissions, including diaphragm pumps that are operated manually, triggered by a level controller, or operated temporarily or seasonally.

Alternatively, EPA could use the operating time of a pump with exhaust rate of 22.45 scf/hour (equivalent to assume emission rate of a diaphragm pump from the technical support document) that would result in 53,000 scf/year of emissions, which is 96.5 days. This could be rounded down to 90 days of operation, or 2,160 hours. This approach would simplify the exemption, as companies would track the hours of operation instead of calculating the exact exhaust rate.

API proposes the following amendments to §60.5365a(h)(1) and (h)(2):

> "(h)(1) For natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven chemical/methanol pump or a natural gas-driven diaphragm pump with an exhaust rate greater than 53,000 scf/yr and that operates more than 2,160 hours per year.
>
> (2) For locations other than natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven chemical/methanol pump or a natural gas-driven diaphragm pump with an exhaust rate greater than 53,000 scf/yr and that operates more than 2,160 hours per year, and for which a control device owned and operated by the owner and operator of the pump is located on site and not demonstrated to be technically infeasible to control."

Note that there are additional revisions to §60.5365a(h)(2) proposed in Section 20 and 24.4.5. See 24.4.5 for combined language.

24.4.2 The Rule Text Should Exempt Portable Pneumatic Pumps.

There are many scenarios where portable pneumatic pumps are used by industry for infrequent and temporary operations, such as pumping out a tank or a sump. Since these pumps will, by their very nature, result in very low emissions, portable pumps should be exempt from the rule. Such as exemption would be analogous to that provided to portable or transportable (has wheels, skids, carrying handles, dolly, trailer or platform) engines relative to the NSPS RICE rules.

API recommends that EPA update the definition of pneumatic pump under the rule to exclude temporary and portable pumps.

EPA should amend the definition under §60.5430a to address these temporary and portable sources, i.e. "A temporary or portable pump is considered a stationary source under this rule if the stays in one location for more than 12 months (or full annual operating period of a seasonal source)." (See revised definition under 24.4.3.)

24.4.3 The Rule Text Should Be Clearer On Exclusion Of Lean Glycol Circulation Pumps (Often Referred To As Kimray Pumps) On Dehydration Units (As Intended By The Preamble Language).

EPA's intent is clear in the Preamble (FR 56627) that EPA is not proposing to regulate gas assist lean glycol circulation pumps on glycol dehydration units. However, the regulatory text does not make this exclusion clear.

EPA can improve this by having a single modified definition under §60.5430a rather than two inconsistent definitions for chemical/methanol or diaphragm pumps and natural gas-driven chemical/methanol or diaphragm pumps. Neither defined term is used in the rule text itself which is also confusing.

API proposes an updated definition under §60.5430a as follows:

Remove the following definition:

~~"Chemical/methanol or diaphragm pump means a gas-driven positive displacement pump typically used to inject precise amounts of chemicals into process streams or circulate glycol compounds for freeze protection."~~

API recommends adding following definition:

Natural gas-driven chemical/methanol or diaphragm pump *means a* natural gas-driven positive displacement pump used to inject chemicals into process streams or circulate glycol compounds for freeze protection. A lean glycol circulation pump on a glycol dehydration unit is not a chemical/methanol or diaphragm pump. A temporary or portable pump is considered a stationary source under this rule if the pump stays in one location for more than 12 months (or full annual operating period of a seasonal source).

24.4.4 The Rule Should Allow For Removal Of Control Device – i.e. Pneumatic Pump No Longer Has To Be Controlled If Control No Longer Present.

If a control device is no longer needed for the purpose for which it was originally installed, EPA should clarify that any pneumatic pumps that were routed to the device should no longer require control. A control device should not be required to remain in service only for the purpose of controlling one or more pneumatic pumps.

For example, NSPS Subpart OOOO allows for removal of control device from a storage vessel if emissions fall below a certain level. Specifically, under the NSPS, EPA has allowed for the removal of control devices once emissions are below 4 TPY (40 CFR 60.5395(d)(2) and 60.5395a(a)(3)). In the preamble to the NSPS OOOO revisions dated April 12, 2013 (Federal Register Vol. 78, No. 71, 22133-22134) EPA also noted that removal of control at 4 TPY will help relieve the control device shortage issue as well as reduce emissions from burning more pilot gas than the waste gas being burned. If a control device is removed, the requirement to route pneumatic pump exhaust to the control device should no longer be applicable.

24.4.5 EPA Must Define "Control Device" In The Context Of Its Use In The Requirements For Pneumatic Pumps

§60.5365a(h)(2) states:

> *(2) For locations other than natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven chemical/methanol pump or natural gas-driven diaphragm pump for which a control device is located on site.*

Control device is not a defined term and should be specifically defined to clarify EPA's intent which, from review of the complete NSPS OOOOa proposal and TSD, appears to be to utilize combustion control devices and/or VRUs if available. This issue is discussed in Section 13.0, and a definition recommended that will eliminate the issues related to the uncertainty of when the pneumatic pump requirements apply.

However, if EPA does not elect to incorporate API's suggested changes in Section 13.0, then EPA must make revisions within §60.5365a(h)(2) to clarify this situation. Specifically, API recommends the following change:

> ***§60.5365a(h)(2)*** *For locations other than natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven chemical/methanol pump or natural gas-driven diaphragm pump for which a control device is located on site.*
>
> For the purpose of this section, boilers, process heaters, and other combustion devices that burn natural gas to derive useful work or heat are not considered control devices.

Note that there are additional revisions to §60.5365a(h)(2) proposed in Section 20 and 24.4.1.

Combining the edits in Sections 20, Section 24.4.1, and this Section results in:

> **§60.5365a(h)(2)** *For locations other than natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven chemical/methanol pump or a natural gas-driven diaphragm pump that meets the criteria in paragraphs (i) through (iii) and is not excluded by (iv).*
>
> (i) *The pump has an exhaust rate greater than 53,000 scf/yr and operates more than 2,160 hours per year.*
>
> (ii) *The pump has a control device owned and operated by the owner and operator of the pump is located on site. For the purpose of this section, boilers, process heaters, and other combustion devices that burn natural gas to derive useful work or heat are not considered control devices.*
>
> (iii) *The pump has not been demonstrated to be technically infeasible to control.*
>
> (iv) *A pneumatic pump that is in compliance with a legally and practically enforceable requirement that requires the reduction of VOC or methane is not an affected facility.*

24.4.6 The Control Device Must Be Owned And Operated By The Pump Owner And Operator

EPA must be clear that a control device on site must be owned and operated by the same company that owns and operates the pumps. For instance, the dehydration unit located on a production site may be owned and operated by the gathering company, not the producer. If there is a dehydration unit on site with a control device that is owned and operated by the gathering company, the producer has no right to route pump exhaust to the control device and should not be required to route the pump exhaust to the dehydration control device owned and operated by a separate entity.

24.4.7 Heaters Should Not Be Considered As Existing Control Devices – I.E. Pneumatic Pump Exhaust Should Not Be Required To Be Routed To A Heater Simply Because One Is Present.

The language in §60.5412a describes requirements that each control device must meet and this list includes process heaters. This language could be misinterpreted to mean that any process heater should be considered a control device and thus, its presence would require routing of a pump exhaust to the heater. It is not believed that this was EPA's intent.

> EPA should clarify that routing emissions to a process heater should be considered "routing to a process" and the heater should not be considered as a control device. More discussion on this topic is provided in section 13.0. However, if EPA does not elect to incorporate API's suggested changes in section 13.0, then EPA must make revisions in §60.5365a(h)(2) to clarify this situation. The recommended changes are shown above in section 24.4.5.

See Section 13.0 of these comments for a complete discussion of the issues associated with treatment of heaters and boilers in Subpart OOOOa.

24.4.8 Non-Affected Facilities (E.G. Pumps Not Requiring Controls Under The NSPS) Should Not Have Obligations Under The Rule.

Under §60.5360a(h)(2), EPA has defined that the OOOOa affected source for pneumatic pumps "for locations other than natural gas processing plants" is a "a single natural gas-driven chemical/methanol pump or natural gas-driven diaphragm pump for which a control device is located on site." However, under §60.5410a(e)(3) and §60.5420a(b)(8)(i), EPA is proposing that you must submit a certification if the pneumatic pump is not controlled by 95% because a control devices is not available at the site.

A pump at a site without a control device is not an affected source and should not have requirements under OOOOa. EPA should remove the requirements requiring certification for pumps located at sites without control devices.

> **API recommends that §60.5410a(e)(3) and §60.5420a(b)(8)(i) should be removed from the proposed rule.**

24.5 Reporting and Recordkeeping

24.5.1 Remove The Tagging Requirement.

It is unclear what EPA's intent is for requiring tagging of affected natural gas driven pneumatic pumps under §60.5393a(a)(2), §60.5393a(b)(3) and §60.5410a(e)(4). The applicability is clear that if the pump is new, modified, or reconstructed after September 18, 2015, not at a natural gas processing plant, and with a control device on site. The tagging appears to add little value.

Furthermore, it is confusing that tagging be required for pneumatic pumps that are not affected facilities because a control device is not on-site (as required by §60.5410a(e)(4)).

API requests that EPA remove the following paragraphs related to tagging:

> ~~§60.5393a(a)(2): Each pneumatic pump affected facility at 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 pneumatic pump as required in § 60.5420a(c)(16)(i).~~
>
> ~~§60.5393a(b)(3) 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 § 60.5420a(c)(16)(i).~~
>
> ~~§60.5410a(e)(4) You must tag each new pneumatic pump affected facility according to the requirements of § 60.5393a(a)(2) or (b)(3).~~

Alternatively: API requests that EPA at least limit tagging such that it is only required for pumps with a control device on site for which control has been determined to be technically infeasible.

24.5.2 EPA Should Remove The Recordkeeping Requirements For Control Devices And Closed Vent Systems

As discussed in Section 24.3.1, EPA's costs for controlling pneumatic pumps not located at a natural gas processing plants did not include the cost of the recordkeeping and reporting requirements in the cost estimate. The recordkeeping and reporting requirements that EPA has included are burdensome in some cases and expand requirements to non-affected sources.

- §60.5420a(b)(8)(i) requires certification of non-affected sources (See also Section 24.4.8).
- §60.5420a(b)(8)(v) requires testing data to be submitted that is not accounted for in the cost analysis, not cost effective when included, and not needed based on the exhaust gas being natural gas, which is the same as the pilot of the combustion device. EPA should remove the combustion control device testing, monitoring, reporting, and recordkeeping requirements.
- §60.5420a(c)(16)(i) – It is not clear what EPA means by records of "the manufacturer specifications". EPA should clearly specify what they want here. It is assumed this refers to the make and model of the pump.
- §60.5420a(c)(16)(iii) – This provision requires continued tracking of the data of a pump being constructed, reconstructed, or modified at a non-natural gas processing plant location that did not have a control device that later has one installed. Pumps should only be triggered at the time the pump is installed. Labor intensive compliance tools will be required to track the location of the pumps as they move from site to site. The cost of these systems and the manpower to maintain them were not included in EPA's cost of control.
- §60.5420a(c)(16)(iv) – As discussed in Section 24.3.1, EPA should remove the combustion control device testing, monitoring, reporting, and recordkeeping requirements as they are not accounted for the in the cost and not cost effective once included.
- §60.5420a(c)(16)(v) appears to reference the wrong requirements in the rule. It shows that the photograph with latitude and longitude would be a substitute for the records for

the control device monitoring and testing. It should refer to the location, make, and model requirements under (i).

In many instances, these controls have been installed under a state permit (or other regulatory requirement) and have compliance assurance requirements associated with those requirements. It is inappropriate to add new compliance assurance requirements that may conflict to the original requirements the control device was installed to meet. Additionally, the control device may not be able to meet or be retrofitted to meet (i.e. install sample ports) to meet the compliance assurance requirements of OOOOa.

API recommends the following amendment to the rule language §60.5420(b) and (c):

§60.5420(b)(8) For each pneumatic pump affected facility, the information specified in paragraphs (b)(8)(i) through (v) of this section.

~~(i) In the initial annual report, a certification that there is no control device on site, if applicable.~~
(ii) An identification of each pneumatic pump constructed, modified or reconstructed during the reporting period, including the identification information specified in §60.5393a(a)(2) or (b)(2).
(iii) An identification of any sites which contain natural pneumatic pumps and which installed a control device during the reporting period, where there was no control device previously at the site.
(iv) Records of deviations specified in paragraph (c)(16)(ii) of this section that occurred during the reporting period.
~~(v) If complying with §60.5393a(b)(1) with a control device tested under §60.5413(d), which meets the criteria in §60.5413(d)(11) and §60.5413(e), records specified in paragraphs (c)(16)(iv)(A) through (G) of this section for each pneumatic pump constructed, modified or reconstructed during the reporting period.~~

§60.5420a(c)(16) For each pneumatic pump affected facility, you must maintain the records identified in paragraphs (c)(1)(i) through (iv) of this section.

(i) Records of the date, location and ~~manufacturer specifications~~ <u>make and model</u> for each pneumatic pump constructed, modified or reconstructed.
(ii) Records of deviations in cases where the pneumatic pump was not operated in compliance with the requirements specified in §60.5393a.
(iii) ~~Records of the control device installation date and the location of sites containing pneumatic pumps at which a control device was installed, where previously there was no control device at the site.~~
(iv) ~~Except as specified in paragraph (c)(16)(iv)(G) of this section, records for each control device tested under §60.5413a(d) which meets the criteria in §60.5413a(d)(11) and §60.5413a(e) and used to comply with §60.5393a(b)(1) for each pneumatic pump.~~
~~(A) Make, model and serial number of purchased device.~~
~~(B) Date of purchase.~~
~~(C) Copy of purchase order.~~
~~(D) Location of the pneumatic pump and control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.~~
~~(E) Inlet gas flow rate.~~
~~(F) Records of continuous compliance requirements in §60.5413a(e) as specified in paragraphs (c)(16)(iv)(F)(1) through (4) of this section.~~
~~(1) Records that the pilot flame is present at all times of operation.~~

~~(2) Records that the device was operated with no visible emissions except for periods not to exceed a total of 2 minutes during any hour.~~
~~(3) Records of the maintenance and repair log.~~
~~(4) Records of the visible emissions test following return to operation from a maintenance or repair activity.~~

(G) As an alternative to the requirements of paragraph (c)(16)(i~~v~~)(D) of this part, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the pneumatic pump and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the pneumatic pump and control device 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.

25.0 STORAGE VESSELS

25.1 The Language For Applicability In Subpart OOOOa Needs To Be More Clear About Tanks That Do Not Receive Liquid From Hydraulically Fractured Wells (Time Limit)

Proposed paragraph §60.5365a(e) specifies that the potential for VOC emissions must be calculated "for a 30-day period of production prior to the applicable emission determination deadline specified in this section." Paragraph §60.5365a(e)(1) then specifies this deadline for storage vessels receiving liquids from well affected facilities (i.e., a hydraulically fractured wells with a GOR greater than 300 scf/bbl) as "30 days after startup of production." There are multiple issues with this paragraph.

First, there are no deadlines specified for newly constructed, reconstructed, or modified storage vessels that receive liquids from sources other than hydraulically fractured wells. Presumably, EPA intends that such tanks with potential VOC emissions greater than 6 tons per year would be subject to the rule.

Second, for tanks that are not installed at the onset of production for a well, the 30 days after startup of production is not relevant. Rather, this period should be based on 30 days after the storage vessel is put into service.

Therefore, API recommends the following amendments to the proposed provisions of §60.5365a(e) and (e)(1).

(e) Each storage vessel affected facility, which is a single storage vessel with the potential for VOC emissions equal to or greater than 6 tpy as determined according to this section, except as provided in paragraphs (e)(1) through (4) of this section. The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline specified in paragraph (e)(1) of this section. The determination may take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a Federal, State, local or tribal authority.

(e)(1) For each new, modified or reconstructed storage vessel receiving liquids pursuant to the standards for well affected facilities in §60.5375a, including wells subject to §60.5375a(f), you must determine the potential for VOC emissions within 30 days after startup of production (i.e., the date that the storage vessel is placed into service).

25.2 EPA Should Provide Clarity For The Process For Assessing Applicability For Replacement Tanks

Proposed paragraph §60.5365(e)(4) attempts to provide the requirements for determination of applicability for storage tanks that replace existing tanks. However, this paragraph is very confusing in existing OOOO, thus leaving the regulated community and state and local air pollution agencies reeling. This has resulted in various and inconsistent interpretations and policies in the implementation of Subpart OOOO. API recommends that EPA correct these issues in Subpart OOOOa.

Paragraph (e)(4) specifically applies to "each new, reconstructed, or modified storage vessel with startup, startup of production, or which is returned to service". While there are numerous questions and issues related to "returned to service" that are discussed below, the tanks EPA that is attempting to address by "each new, reconstructed, or modified storage vessel with startup of production" is not clear. These criteria would apply to every storage vessel, leaving question about the relationship between the basic applicability provisions in paragraph (e) apply versus those in (e)(4). API believes that it is EPA's intent that paragraph (e)(4) apply to storage vessels that replace existing storage vessels. There are various scenarios under which a tank may be added. For several of these scenarios, the existing provisions in Subpart OOOO, and the proposed provision in Subpart OOOOa, are not clear. Table 22-1 describes those scenarios, along with API's interpretation of EPA's intention. After the scenarios, API provides suggested regulatory language to clarify these situations moving forward.

Table 25-1 Interpretation of EPA's Intention for the Applicability of the Storage Vessel Provisions Subparts OOOO and OOOOa for Various Scenarios

Scenario	*Interpretation of EPA's Intention for Determining Applicability for Storage Vessels*
A storage vessel constructed, reconstructed, or modified after September 18, 2015 is added at a new site.	Applicability is determined according to §60.5365a(e) and (e)(1), where the 30 day period begins at the startup of production (*when the storage vessel is put into service – see recommendation above*)
A storage vessel constructed, reconstructed, or modified after September 18, 2015 is added at an existing site but not as a replacement for an existing tank.	Applicability is determined according to §60.5365a(e) and (e)(1), where the 30 day period begins when the storage vessel is put into service
A storage vessel constructed, reconstructed, or modified after September 18, 2015 is added at an existing site as a replacement for an existing tank that was a storage vessel affected facility subject to Subpart OOOOa.	The new storage vessel is an affected facility subject to Subpart OOOOa.
A storage vessel constructed, reconstructed, or modified after September 18, 2015 is added at an existing site as a replacement for an existing tank that was a not a storage vessel affected facility subject to Subpart OOOOa.	Applicability is determined according to §60.5365a(e) and (e)(1), where the 30 day period begins when the storage vessel is put into service.
A storage vessel constructed, reconstructed, or modified prior to September 18, 2015 is added at any site (even if it is a replacement for an existing tank that was a storage vessel affected facility subject to Subpart OOOOa.)	The storage vessel is not an affected facility subject to Subpart OOOOa.
A storage vessel affected facility formerly subject to Subpart OOOOa that was removed from service that is reconnected to the original source of liquids.	The storage vessel is an affected facility and subject to Subpart OOOOa.
A storage vessel affected facility formerly subject to Subpart OOOOa that was removed from service that is put back into service at a different location.	See scenarios 1 through 4.

API suggests the following that proposed §60.5365a(e)(4) be entirely replaced with the following, and that (e)(5) be added as follows.

(4) Each storage vessel that was constructed, reconstructed, or modified after September 18, 2015 that replaces an existing storage vessel shall determine applicability according to the provisions in (e)(4)(i) or (ii).

(i) If the storage vessel being replaced is a storage vessel affected facility, the new storage vessel is an affected facility.

(ii) If the storage vessel being replaced is not a storage vessel affected facility, applicability shall be determined in accordance with paragraph (e) and (e)(1) of this section.

(5) Each storage vessel affected facility formerly subject to Subpart OOOOa that was removed from service in accordance with §60.5395a(c) that is put back into service shall determine applicability according to the provisions in (e)(5)(i) or (ii).

(i) If the storage vessel is reconnected to the original source of liquids, it is a storage vessel affected facility subject to the same requirements as before being removed from service.

(ii) If the storage vessel is put back into service and not reconnected to the original source of liquids, applicability shall be determined in accordance with paragraph (e)(4) of this section.

API would also recommend that analogous changes be made to §60.5365(e).

25.3 EPA Should Clarify That Hydraulic Fracturing Or Refracturing Does Not Constitute A Modification To A Tank.

When a well is refractured, it is likely that the storage vessel that receives the liquids from the well will see an increase in throughput from the time period just prior to the refracture (even though it is unlikely that it will increase throughput from the original throughput). Proposed paragraph §60.5365a(a)(3) is clear that in this situation, refracturing a well does not affect the modification status of other downstream equipment, including storage vessels. API supports this clarification.

However, the rule does not address similar situations where well activity could increase the throughput of a tank for which Subpart OOOOa applicability has already been determined. A few examples include when a new well (hydraulically fractured or not) is tied into the storage vessel, when another storage vessel at the site is taken out of service, or the liquids flow at a site with multiple tanks is altered.

To clarify these situations, API suggests the addition of a paragraph §60.5365a(e)(6). Suggested language is as follows:

(6) For the purposes of this Subpart, after the initial applicability determination for a storage vessel has been conducted in accordance with the requirements of paragraph (e) and (e)(1), situations that increase the throughput of that storage vessel shall not be considered modifications and shall not require a new applicability determination.

25.4 EPA Should Modify The Definition Of "Maximum Daily Average Throughput" To Reflect Their Intentions Regarding Storage Tank Applicability Determinations

For the applicability determination for storage vessel affected facilities, proposed §60.5365a(e)(1) requires that the emissions must be calculated "The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline specified in this section." While the term "maximum average daily throughput" is both a plain language and mathematical contradiction, EPA attempted to clarify this term in proposed §60.5430a. This definition is as follows:

> *"Maximum average daily throughput means the earliest calculation of daily average throughput during the 30-day PTE evaluation period employing generally accepted methods."*

While this definition clarifies the "maximum average" aspect of the term, there are still numerous issues that need to be addressed with this definition.

First, the inclusion of the word "earliest" is problematic and it adds no value. Proposed §60.5365a(e) requires that "you must determine the potential for VOC emissions within 30 days after startup of production." Since the determination must be done for a 30-day period within 30 days after startup of production, there is only one 30 day period. The period is well defined. Therefore, EPA should remove the word "earliest" from this definition.

Second, requiring the maximum daily average to be calculated based strictly on a calculation of the average throughput for the first 30 days of production does not recognize the situations experienced in practice. The determination should be based on the maximum daily throughput at steady state conditions, which is often not likely represented by the calculation of the average throughput for the first 30 days. It is true that typically the initial 30-day period will represent the maximum production the well is expected for the life of the well due to reservoir depletion. However, the first 30-days of production are typically non-steady state operations, containing both shut-in periods for operational reasons and short, spike flow periods (minutes to hours) after the production valves are opened after the well has been shut-in. Including either the peak flow periods or shut-in periods adulterates the average throughput experienced during the initial 30 days of production. Basing the determination solely on the average throughput for this period could result in tanks with the potential to emit VOC at levels much higher than 6 tons per year not being subject (e.g., if there were multiple shut-in days), and tanks with potential VOC emissions much lower than 6 tons per year being subject (e.g., if there were numerous spikes). The appropriate throughput, which is entirely consistent with EPA's intention, is that the applicability determination be based on maximum daily throughput during the initial 30-day period that represents steady state conditions. Finally, the concept of generally accepted methods is already clear in §60.5365a(e). Repeating it in the definition of maximum average daily throughput is unnecessary and potentially confusing.

Therefore, API suggests the following change to the proposed definition of maximum average daily throughput.

> "Maximum average daily throughput means the ~~earliest calculation of~~ daily average throughput during the 30-day PTE evaluation period that represents steady-state conditions~~employing generally accepted methods~~."

25.5 Under §60.5395a(A)(3), The Re-Installation Of Controls To Achieve 95% Should Not Be Required When Liquids From The Well Following Fracturing Or Refracturing Are Routed To The Storage Vessel Affected Facility If Emissions Do Not Increase To Greater Than 4 TPY

Section §60.5395a(a)(3) includes an alternative emission limitation to allow for situations when production declines and the uncontrolled VOC emissions from the storage vessel fall below 4 tpy for 12 consecutive months. This is entirely consistent with the requirements in §60.5395(a)(3) of Subpart OOOO. In the preamble for the final amendments that added this alternative to §60.5395(a)(3) of Subpart OOOO, EPA stated the following:

> *"In light of the cost effectiveness, the secondary environmental impacts and the energy impacts, we have concluded that the BSER for reducing VOC emission from storage vessel affected*

> *facilities is not represented by continued control when their sustained uncontrolled emission rates fall below 4 tpy." (78 FR 58429, September 23, 2013)*

In proposed §60.5395a(a)(3)(ii), controls would need to be re-instated if the emissions increase to 4 tpy or greater based on one month's emissions. API does not take issue with this requirement.

However, paragraph §60.5395a(a)(3)(i) also requires that controls be re-instated if the well feeding the storage vessel affected facility undergoes fracturing or refracturing as soon as liquids are routed to the storage vessel, without regard to the VOC emissions level. This requirement is consistent with Subpart OOOO. EPA justified this by stating that this situation is "likely to release substantial amounts of vapor if not controlled right away due the initially high liquid flow and flash emissions from freshly fractured or refractured wells. We also believe that potential emissions associated with fracturing and refracturing of a well are unlikely to meet the 4 tpy uncontrolled emission rate." (78 FR 58431, September 23, 2015)

API does not believe that this requirement is warranted. While is it true that production, and storage tank emissions, would likely increase after the fracturing or refracturing, EPA cannot arbitrarily assume that this reduction would automatically result in VOC emissions greater than 4 tpy. EPA provided no data to support this assertion. EPA has clearly stated that BSER is not represented by control when emissions are less than 4 tpy, and this requirement has the clear potential to require control on tanks that is at a level that EPA has clearly determined is not cost effective.

Therefore, EPA should remove paragraph §60.5395a(a)(3)(i) and only rely on the requirements currently in paragraph §60.5395a(a)(3)(ii); if indeed the fracturing or refracturing does result in a VOC emissions level greater than 4 tpy, then the tank would be required to be controlled for at least the next 12 months. However, if the VOC emissions were below 4 tpy after the fracturing or refracturing, this would not result in the re-installation of controls that are clearly not cost effective.

Therefore, API recommends the following change to the final Subpart OOOOa.

§60.5395a(a)(3) Maintain the uncontrolled actual VOC emissions from the storage vessel affected facility at less than 4 tpy without considering control. Prior to using the uncontrolled actual VOC emission rate for compliance purposes, you must demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy as determined monthly for 12 consecutive months. After such demonstration, you must determine the uncontrolled actual VOC emission rate each month. The uncontrolled actual VOC emissions must be calculated using a generally accepted model or calculation methodology, and the calculations must be based on the average throughput for the month. You must comply with paragraph (a)(2) of this section within 30 days of the monthly determination if the monthly emissions determination required in this section indicates that VOC emissions from your storage vessel affected facility increase to 4 tpy or greater~~. your storage vessel affected facility meets the conditions specified in paragraphs (a)(3)(i) or (ii) of this section.~~

~~(i) If a well feeding the storage vessel affected facility undergoes fracturing or refracturing, you must comply with paragraph (a)(2) of this section as soon as liquids from the well following fracturing or refracturing are routed to the storage vessel affected facility.~~

~~(ii) If the monthly emissions determination required in this section indicates that VOC emissions from your storage vessel affected facility increase to 4 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel affected facility~~, you must comply with paragraph (a)(2) of this section within 30 days of the monthly determination.

API also requests that the same changes be made to §60.5395(a)(3) of Subpart OOOO.

Another alternative would be for EPA to require control immediately as required in paragraph (ii), but then allow controls to be removed after 30 days if the increased production levels would not result in VOC emissions greater than 4 tpy. API does not recommend this solution as the installation costs of a control device can be substantial, but it would be preferred to the proposed requirement that would require that controls be operated for 12 additional months (when uncontrolled VOC emissions never exceeded 4 tpy) before they could be removed.

25.6 Emission Limits/Control Devices

25.6.1 EPA Cannot Retroactively Add Control Requirements To Subpart OOOO.

EPA proposed, as §60.5412(d)(1)(iv), several new requirements for combustion devices used to meet the storage vessel emission reduction standard in §60.5395(d). Specifically, this paragraph would require that each combustion devices be designed and operated in accordance with one of the following four performance requirements.

- Reduce the mass content of methane and VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of §60.5413.
- Reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 600 parts per million by volume as propane on a dry basis corrected to 3 percent oxygen as determined in accordance with the requirements of §60.5413.
- Operate at a minimum temperature of 760°C for a control device that can demonstrate a uniform combustion zone temperature during the performance test conducted under §60.5413.
- If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

First, Subpart OOOO currently only requires, in §60.5412(d)(1), that each enclosed combustor be "designed to reduce the mass content of VOC emissions by 95.0 percent or greater." The addition of these proposed requirements in §60.5412(d)(1)(iv) means that an owner/operator fully in compliance with the current provisions in §60.5412(d)(1) could find themselves unable to comply with the new requirements in §60.5412(d)(1)(iv).

Second, the first three options require that compliance be demonstrated in accordance with §60.5413. However, the requirements in §60.5413(b), which would be used to demonstrate compliance with these options, do not apply to control devices for storage vessel affected facilities. Specifically, the introduction to §60.5413 indicates that "This section applies to the performance testing of control devices used to demonstrate compliance with the emission standards for your centrifugal compressor affected facility." The only requirements contained in §60.5413 that apply to storage vessels are those in paragraph (d), which are specific to combustion devices tested by the manufacturer. As discussed in more detail below in section 6.6, EPA did not propose any testing requirements for storage vessel combustion devices not tested by the manufacturer. Therefore, the reference to §60.5413 proposed in §60.5412(d)(1)(iv)(A) through (C) has no context.

For these reasons, EPA must not finalize the proposed requirements in §60.5412(d)(1)(iv)(A) of Subpart OOOO.

25.6.2 EPA Has Not Justified The Change To Route Storage Vessel Emissions To A Process That Achieves 95% Control.

In proposed Subpart OOOOa, §60.5395a(b)(1) requires that emissions from storage vessel affected facilities be routed through a closed vent system to a control device that meets the requirements of

§60.5412a(c) and (d). It also provides that, as an alternative, these emissions may be routed through a closed vent system "to a process that reduces VOC emissions by at least 95.0 percent."

API objects to this 95 percent requirement, as EPA has not provided any justification or rationale for its inclusion. Therefore, it must be removed.

First, it is inconsistent with the analogous requirements for storage vessels in §60.5395(b)(1) of Subpart OOOO, as well as the requirements in A.2(b)(1) of the draft CTG. Further, the proposed parallel proposed requirements for centrifugal compressors at §60.5380(a)(2) and pneumatic pumps at §60.5393(b)(4) do not include this requirement. EPA has not explained or justified why this requirement would apply only to storage vessel affected facilities subject to Subpart OOOOa.

Second, EPA did not include any explanation or process in the proposed Subpart OOOOa detailing how to demonstrate compliance with this requirement. EPA did not provide any technical or other justification for the inclusion of this additional requirement when emissions from a storage vessel affected facility are routed to a process. In fact, API does not find any mention of the addition of this requirement in the preamble.

Finally, the CVS requirements in proposed paragraph §60.5411a(c)(2) already require that CVS be operational 95 percent of the year or greater when emissions are routed to a process. This further makes the proposed requirement in §60.5395a(b)(1) unnecessary.

Therefore, EPA should make the following change to the proposed requirements in §60.5395a(b)(1) for the final rule:

§60.5395a (b) Control requirements. (1) Except as required in paragraph (b)(2) of this section, if you use a control device to reduce VOC emissions from your storage vessel affected facility, you 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). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process ~~that reduces VOC emissions by at least 95.0 percent~~.

25.7 Testing and Monitoring

25.7.1 EPA Must Clarify That No Performance Testing Requirements For Storage Vessel Affected Facilities Were Proposed For NSPS Subpart OOOO

Throughout the preamble, EPA discusses the implementation improvements made as a result of the reconsideration of issues raised in administration reconsideration petitions on the 2012 final rule. One of the major implementation improvements is related to the performance testing requirements for control devices used to comply with the storage tank requirements. For example:

> *"In this rulemaking, the EPA is granting reconsideration of a number of issues raised in the administrative reconsideration petitions and, where appropriate, is proposing amendments to address such issues. These issues, which mostly address implementation, are as follows: storage vessel control device monitoring and testing provisions, .." (80 FR 56598)*
>
> *"As proposed, initial and ongoing performance testing will be required for any enclosed combustors used to comply with the emissions standard for an affected facility and whose make and model are not listed on the EPA Oil and Natural Gas Web site . . . . Performance testing of combustors not listed at the above site would also be conducted on an ongoing basis, every 60 months of service, and monthly monitoring of visible emissions from each unit is also required." (80 FR 56645)*

These statements are reflected in proposed Subpart OOOOa. Specifically, §60.5410a(h)(4) and §60.5413a(b)(5)(i) both would require that initial performance tests be conducted "within 180 days after initial startup." In addition, §60.5410a(h)(4) adds "or within 180 days of [date 60 days after publication of final rule in the **Federal Register**], whichever is later". While this inconsistency creates confusion for those sources that have a startup date prior to 60 days after publication of the final rule, it is clear that EPA intends to require initial performance testing for control devices used to comply with the Subpart OOOOa storage vessel requirements. The periodic performance testing requirements are also clear in Subpart OOOOa, as both §60.5413a(b)(5)(ii) and §60.5417a(h)(4) would require periodic tests every 60 months after the initial test.

API notes that the initial and periodic performance test requirements for storage vessel control devices in the model rule language in the draft Control Technique Guidelines released by EPA on September 18, 2015 (80 FR 56577) is consistent with the proposed Subpart OOOOa.

However, it is not clear whether EPA intended to include these same performance testing requirements in the proposed amendments to Subpart OOOO. There are no amendments proposed that would require an initial performance test for storage vessels. In Subpart OOOO, no paragraph was added to §60.5410(h) that is analogous to the initial testing requirement for storage vessels proposed in §60.5410a(h)(4), and §60.5413(b) only applies to control devices used to meet the centrifugal compressor requirements in §60.5412(a). Note that proposed §60.5413a(b) clearly states that the provisions in that section, including the initial testing requirements in §60.5413a(b)(5)(i), apply to control devices meeting the centrifugal compressor requirements in §60.5412a(a) and the storage tank requirements in §60.5412a(d).

Based on the lack of proposed amendments to Subpart OOOO described above, it could be assumed that EPA did not intend to apply testing provisions for storage vessel control devices for storage vessel affected facilities constructed, reconstructed, or modified between August 23, 2011 and September 18, 2015. However, this interpretation is clouded by the fact that EPA did propose to add paragraph §60.5417(h)(4), which requires periodic performance tests. However, it is unclear whether EPA intended to require periodic testing for storage vessel control devices subject to Subpart OOOO or whether this was an inadvertent inclusion.

Proposed paragraph §60.5417(h)(4) states:

> *(4) Conduct a periodic performance test no later than 60 months after the initial performance test as specified in §60.5413(b)(5)(ii) and conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test.*

Based on the rationale below, API concludes that EPA did not intend to require this testing for storage vessel affected facilities.

- The introductory text for §60.5410(h) indicates that in order to demonstrate continuous compliance for a storage vessel affected facility, the requirements of paragraphs (h)(1) through (3) must be met. This language was not amended to include a reference to paragraph (4). Therefore, technically, compliance with this paragraph is not required.
- Proposed §60.5417(h)(4) indicates that the periodic performance test be performed 60 months after the initial performance test as specified in §60.5413(b)(5)(ii). However, §60.5413(b)(5)(ii) applies only to centrifugal compressor affected facilities and, as discussed above, there is no requirement for initial performance testing for storage vessel affected facilities.
- The preamble did not indicate that these implementation improvements were applicable to Subpart OOOO.

- EPA clearly did not estimate the cost of testing in any of their justification for the proposed amendments to Subpart OOOO.

Therefore, EPA must remove the proposed §60.5410(h)(4) to clarify that clearly they did not intend to retroactively apply the implementation improvements related to storage vessel initial and periodic testing to storage vessel affected facilities subject to Subpart OOOO.

25.7.2 EPA Cannot Finalize Performance Testing Requirements For Storage Vessel Affected Facilities For NSPS Subpart OOOO

API recognizes the possibility that EPA did intend to require initial and periodic performance testing for storage vessel affected facilities under Subpart OOOO. If this was the case, EPA must not include such provisions in the final rule. As discussed above, EPA clearly did not propose such amendments on September 18, 2015. Therefore, the public did not have the opportunity to comment on such proposed requirements. Even if EPA attempts to claim that it was their intention to propose testing requirements for storage vessel affected facilities subject to Subpart OOOO, there are numerous aspects related to the addition of these requirements that would need to be included (e.g., When is the initial performance test required? What if the control device met the required to be "designed" to achieve 95% reduction but cannot meet achieve such reduction during a performance test?). EPA is not allowed to finalize such provisions without providing the opportunity for the public to comment.

If EPA elects to move forward and require initial and periodic testing of control devices for storage vessel affected facilities under Subpart OOOO, they must issue a separate proposal and allow the opportunity for the public to comment.

Further, as discussed below, the storage vessel testing and monitoring requirements proposed for Subpart OOOOa are inappropriate, infeasible, and unjustified.

25.7.3 API agrees that Continuous Parameter Monitoring is not warranted for Storage Vessel Control Devices

In NSPS Subpart OOOO, EPA proposed only two changes to the monitoring requirements for storage vessel control devices:

(1) Visible emission tests would be required on a monthly basis (instead of quarterly) for manufacturer testing combustion devices - §60.5413(e)(3), and

(2) The criteria for this visible emission test was modified as follows: Devices must be operated with no visible emissions, except for periods not to exceed a total of ~~2 minutes during any hour~~ 1 minute during any 15-minute period.

The requirements in proposed Subpart OOOOa are consistent with these changes to Subpart OOOO.

Notably absent are requirements to perform continuous parameter monitoring. API agrees that continuous parameter monitoring is not warranted and supports that EPA elected not to include such provisions in the proposed amendments to Subpart OOOO or the proposed Subpart OOOOa.

However, in the draft CTG model rule, the storage vessel control device monitoring requirements are considerably different. In section A.4(c) of the model rule, continuous parameter monitoring and the comparison of daily average parameter monitoring results against site-specific maximum or minimum values established during the performance test are required. In our comments on the CTG, we explain how these monitoring requirements are unrealistic and unjustified.

This is a significant discrepancy in the proposed NSPS and draft CTG model rule monitoring requirements. If in fact the EPA intended for the NSPS monitoring requirements in both Subpart OOOO and Subpart OOOOa to include continuous parameter monitoring as in the CTG, EPA must issue a separate proposal and allow the opportunity for the public to comment.

25.8 EPA Should Only Require Control When There is Flow into the Storage Vessel

Temporary shut-ins can result in a loss of gas supply to the flare pilot, rendering the control device non-operational. During such temporary shut-ins, working and flash losses from storage vessels cease completely because the producing well stopped flowing. A negligible amount of breathing loss (evaporation) emissions may continue to occur. The current language in §60.5412(d)(3) is:

> *You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the storage vessel affected facility through the closed vent system to the control device.*

Thus, to control only the remaining, negligible breathing losses during a temporary well shut in, a supplemental source of fuel gas may need to be purchased to operate the pilot for a flare or combustor. In some cases that is not even a viable option due to the remoteness of the location and thus the temporary shut-in could result in a requirement to empty, degas and clean the storage vessel before conducting the maintenance activity that would result in a temporary shut-in. API suggests the following revision to §60.5412(d)(3) to address this issue.

> §60.5412(d)(3) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes from working or flash losses are vented from the storage vessel affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

26.0 EPA MUST RESOLVE THE OVERLAP AND REDUNDANCY BETWEEN THE COVER AND CLOSED VENT SYSTEM AND FUGITIVE EMISSION REQUIREMENTS

In §60.5416a, EPA proposes initial and continuous inspection and monitoring requirements for covers and closed vent systems. These requirements consist of a program to identify leaks on covers and closed vent systems and repair them. In addition, EPA proposed a fugitive emissions program in §60.5397a that is also based on identifying and repairing leaks. As proposed, §60.5397a will also apply to covers and closed vent systems, as the definition of "fugitive emissions component" includes "closed vent systems," and "thief hatches or other openings on storage vessels." This results in covers and CVS being subject to both the leak detection and repair requirements in §60.5397a and the leak detection and repair requirements in §60.5416a. This creates a situation which is unnecessarily duplicative and redundant. Table 26-1 provides a summary of these overlapping requirements.

Table 26-1 Summary of the Overlapping Closed Vent System and Cover Requirements in NSPS Subpart OOOO

Affected Equipment/Components	§60.5416a		§60.5397a	
	Inspections	**M21**	**OGI**	**M21**
Centrifugal Compressors and Pneumatic Pumps				
closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (*e.g.,* a welded joint between two sections of hard piping or a bolted and gasketed ducting flange)	(a)(1)(ii) annual visual inspections for defects	(a)(1)(i) Initial, annual, and after repairs/ replacements	(f) – (j) Initially, semiannually (could move to quarterly or	(j)(2) Option for use after repair/ replacement

Affected Equipment/Components	§60.5416a		§60.5397a	
	Inspections	**M21**	**OGI**	**M21**
Closed vent system components other than a joint, seam, or other connection that is permanently or semi-permanently sealed	(a)(2)(iii) annual visual inspections for defects	(a)(2)(i) and (ii) Initial, annual, and after repairs/ replacements	annual depending on % leakers), and after repair/ replacement	
Covers	(a)(3) annual visual inspections for defects	n/a		
Storage Vessels				
Closed vent system	(c)(1) Monthly olfactory, visual and auditory inspections for defects	n/a	(f) – (i) Initially, semiannually (could move to quarterly or annual depending on % leakers), and after repair/ replacement	(j)(2) Option for after repair/ replacement
Covers	(c)(2) Monthly olfactory, visual and auditory inspections for defects			

API does not believe that this was EPA's intention, as EPA did not include component counts and cost estimates for monitoring the storage vessel cover or the closed vent system with the LDAR cost estimates. EPA only included counts in the model plant for components for a wellhead, separator, heater, and dehydration unit according to the Technical Support Document (Table 5-4 and Table 5-5).

API believes that the appropriate and most effective solution is to require the same methodology to monitor the cover and CVS and other fugitive leaks, and that OGI is the most effective methodology. OGI can see the leaks regardless of the type of system. There is no need for additional monitoring on top of the OGI monitoring.

To avoid duplicative monitoring requirements, API recommends clearly defining "closed vent system" consistent with other NSPS Subpart definitions, that is entirely separate from "fugitive emission component". By having a separate definition for closed vent system, a subset of fugitive components is created for affected facilities with closed vent systems that are subject to fugitive monitoring requirements even if the rest of an existing site, for example, is not subject to fugitive monitoring requirements in §60.5397a. The net result is one consistent set of fugitive monitoring requirements that allows for use of OGI whether fugitive components are part of a closed vent system or part of another process.

Following are descriptions of these recommended improvements.

26.1 Define "Closed Vent System"

As noted above, API recommends that EPA add a definition of a closed vent system in §60.5430. The components of a closed vent system may have fugitive components included but also has additional components outside of fugitives that ensure the emissions are being routed to the control device. Under NESHAP Subpart HH, EPA defined closed vent system as

"Closed-vent system means 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."

API recommends the same definition of closed vent system be added to §60.5430a with an additional clarification **(bold)** that would include covers in the definition. This would ensure that all of the leak detection and repair requirements would also apply to components and openings on covers.

> *Closed-vent system* means 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 **except for components and other openings on the cover of the equipment** shall not be considered a closed-vent system and is not subject to closed-vent system standards.

API recognizes that there are a number of interrelated aspects of this definition and the requirements related to the definitions of "routed to a process or route to a process" and "fugitive emissions component", as well as the associated requirements. Due to the insufficient length of the comment period, API is not offering a comprehensive recommendation in these comments. However, API will provide supplementary information with such a recommendation following the end of the comment period.

26.2 Remove Cover and Closed Vent Systems Components from Definition of Fugitive Emissions Component

In order to totally resolve the redundancy in the cover and closed vent system and fugitive component requirements, the definition of "fugitive emissions component" in§60.5430a needs to be modified.

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 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.

API has several other suggestions related to this definition. While they are not shown here since they are not related to closed vent systems and covers, they are provided and discussed in Section 27.2.1.

26.2.1 Remove Section 60.5416a

API recommends that all paragraphs of §60.5416a be removed. As shown in Table 26-2 every relevant requirement of §60.5416a will be addressed by referring to a requirement in §60.5397, or in the case of the bypass requirements, requirements in §60.5411a. In many cases, moving to the OGI-based requirements will result in a more robust program to identify and repair leaks from closed vent systems and cover components. For example, API's recommended changes would require OGI monitoring for all CVS and cover components, rather than the OVA inspection requirements in §60.5416a.

Table 26-2 Side-by-Side Comparison of §60.5416a and §60.5397a Closed Vent System and Cover Requirements

§60.5416a	§60.5416a Requirement	§60.5397a	§60.5397a Requirement
(a)	**CVS and covers for compressors and pumps**		
(1)	CVS Joints, seams and other connectors - Initial M21 and annual visual inspections.	(e) – (i)	All components – OGI monitoring initial and semi-annual
(2)	Other CVS components - Annual M21 and annual visual inspections		
(3)	Covers - Annual visual inspection		
(4)	Bypass	n/a	Not addressed in §60.5397a, but completely addressed in §60.5411a(a)(3)
(b)	M21	not needed	Not needed
(b)(1)-(8)	M21 requirements		
(b)(9)	Repairs - First attempt within 5 days, repair within 15 days.	(j)(1)	Repairs - Repair within 15 days.
(a)(1)(ii)	For CVS Joints, seams and other connectors only – monitor using M21 after repair/replacement	(j)(2)	Resurvey (all components) using OGI or M21 within 15 days of repair
(b)(10)	Delay of repair - If technically infeasible without shutdown – do at next shutdown	(j)(1)	If technically infeasible during operation of the unit, do at next shutdown or within 6 months, whichever is earlier
(b)(11)	Unsafe to inspect	n/a	Not necessary for OGI monitoring
(b)(12)	Difficult to inspect		
(b)(13)	Records	(k)	Records
(c)	**Storage vessels**		
(c)(1)	CVS - Monthly olfactory, visual, and auditory inspections for defects	(e) – (i)	All components – OGI monitoring initial and semi-annual
(c)(2)	Covers Monthly olfactory, visual, and auditory inspections for defects		
(c)(3)	Bypass	n/a	Not addressed in §60.5397a, but completed addressed in §60.5411a(b)(3)
(c)(4)	Repairs – Attempt first attempt within 5 days, repair within 30 days.	(j)	Repairs - Repair within 15 days. Resurvey using OGI or M21 within 15 days of repair
(c)(5)	Delay of repair (If technically infeasible without shutdown – do at next shutdown)	(j)(1)	If technically infeasible during operation of the unit, do at next shutdown or within 6 months, whichever is earlier
(c)(6)	Unsafe to inspect	n/a	Not necessary for OGI monitoring
(c)(7)	Difficult to inspect		

The related recommended rule changes throughout Subpart OOOOa to refer to §60.5397a rather than §60.5416a are provided in section 26.4.

26.3 The Requirements Do Not Need to Address Covers on Uncontrolled Storage Vessels and Covers and Closed Vent Systems on Storage Vessels Subject to Legally and Practically Enforceable Requirements

The changes recommended by API above will eliminate the redundancy in requirements for covers and closed vent systems on centrifugal compressor, pneumatic pump, and storage vessel affected facilities under Subpart OOOOa.

Under the proposed scenario, covers on uncontrolled storage vessels would have been subject to the fugitive emissions requirements. These covers will not be subject to any leak monitoring and repair requirements under the changes recommended by API above. However, as discussed in the following, requiring these covers to be monitored would add no value. If a tank is uncontrolled (i.e. <6 tpy VOC uncontrolled) then leaks would be accounted for as part of the allowable emissions for the uncontrolled storage vessel. Thief hatches and pressure relief devices have an inherent leak rate since they are not welded shut. However, emissions from the thief hatch and pressure relief device are accounted for in the emission determined using EPA's AP-42 7.1 with TANKS 4.09 and when flash emissions are estimated.

Thief hatches that are weighted or spring tensioned serve as emergency overpressure relief devices in addition to providing a point of access for obtaining a sample of the material stored in the storage vessel or for gauging the liquid level. Thief hatches act in combination with the pressure/vacuum (P/V) relief devices to prevent overpressure and bursting of a tank. During normal operations, neither the P/V devices nor the thief hatch will open. In the rare occurrence of overpressure conditions, the P/V devices will open to vent tank vapors. If the P/V devices flow capacity is not sufficient to prevent further overpressure of the tank, then the thief hatch will open to provide additional venting capacity. Such an overpressure incident may be due to a rapid inflow of produced fluid/gas into the storage vessel if, for example, a separator "dump valve" sticks open or fails. The functionality of P/V devices and thief hatches as overpressure relief devices must be preserved to enable safe operation. If the storage vessel is not controlled, these devices are not acting as part of a closed vent system, but rather overpressure relief. Monitoring thief hatches can be complicated to determine the thief hatch is acting as pressure relief device or trying to distinguish the inherent leak rate of the device from a leak. Emissions from operation of a pressure relief device and the inherent leak rate would be considered process emission.

If the tank is controlled under another legally and practically enforceable mechanism like a state permit, the closed vent monitoring requirements for the storage system would be covered by the state, and thus would also be legally and practically enforceable.

26.4 Recommended Changes to NSPS Subpart OOOOa Related to Closed Vent System and Cover Fugitive Monitoring

As noted above, API's recommendation is to have the covers and closed vent requirements throughout Subpart OOOOa refer to the fugitive monitoring and repair requirements in §60.5397a rather than the inspection, monitoring, and repair requirements in §60.5416a. Following are the specific suggested regulatory changes.

> **§60.5397a**(j) ~~For fugitive emissions components also subject to the repair provisions of §§60.5416a(b)(9) through (12) and (c)(4) through (7), those provisions apply instead to those closed vent system and covers, and the repair provisions of paragraphs (j)(1) and (2) of this section do not apply to those closed vent systems and covers~~. You must comply with the requirements of paragraphs (j)(1) and (2) of this section.
>
> **§60.5410a**(b)(4) You must conduct the initial ~~inspections~~ monitoring survey required in ~~§60.5416a(a) and (b)~~§60.5397(j).
>
> **§60.5411a**(a)(2) You must design and operate the closed vent system with no detectable emissions as demonstrated by ~~§60.5416a(b)~~ complying with the requirements for fugitive emission components in §60.5397a.
>
> **§60.5415a**(e)(3)(ii)(A) You must comply with ~~§60.5416a(c)~~ the requirements for fugitive emission components in §60.5397a for each cover and closed vent system.
>
> **§60.5420a(c)**
>
> (5)(i) If required to reduce emissions by complying with §60.5395a(a)(2), the records specified in §§60.5420a(c)(6) through (8)~~, 60.5416a(c)(6)(ii), and 60.5416a(c)(7)(ii)~~. You must maintain the records in paragraph (c)(5)(vi) of this part for each control device tested under §60.5413a(d) which meets the criteria in §60.5413a(d)(11) and §60.5413a(e) and used to comply with §60.5395a(a)(2) for each storage vessel.

(6) Records of each closed vent system and cover inspection monitoring survey required under ~~§60.5416a(a)(1) and (a)(2)~~§60.5397a(f)(g),(h) or (i) for centrifugal compressors, reciprocating compressors and pneumatic pumps, or §60.5416a(c)(1) for storage vessels.

(7) Reserved ~~A record of each cover inspection required under §60.5416a(a)(3) for centrifugal or reciprocating compressors or §60.5416a(c)(2) for storage vessels.~~

(8) Reserved ~~If you are subject to the bypass requirements of §60.5416a(a)(4) for centrifugal compressors, reciprocating compressors or pneumatic pumps, or §60.5416a(c)(3) for storage vessels, a record of each inspection or a record of each time the key is checked out or a record of each time the alarm is sounded.~~

(9) If you are subject to the closed vent system no detectable emissions requirements of ~~§60.5416a(b)~~ §60.5397a for centrifugal compressors, reciprocating compressors or pneumatic pumps, a record of the monitoring conducted in accordance with ~~§60.5416a(b)~~ §60.5397a(k).

27.0 FUGITIVE EMISSIONS AT WELL SITES AND COMPRESSOR STATIONS

27.1 General

The following section addresses comments on EPA's proposed requirements for fugitive component emissions. Comments are organized around the following topics:

- Applicability
- Impacts, Emissions and Costs
- Work Practices and Inspections
- Testing and Monitoring
- Reporting and Recordkeeping.

27.2 Applicability Under §60.5365a(i)

27.2.1 The Definition Of Fugitive Emissions Component Is Confusing, Which Leads To Duplicative Affected Facility Applicability Requirements For Leak Detection And Closed Vent Systems

The definition of *fugitive emission component* is inconsistent with historical definitions for other leak detection programs. In those programs, including the one in Subpart OOOO and OOOOa for gas processing plants, fugitives emission components are defined as *Equipment*. While it may be appropriate to have a separate definition apart from that used in gas processing plants, it should be reflective of the Equipment definition and not be more expansive to include equipment that is neither a fugitive component nor part of another system. Our recommended text changes to the definition can be found at the end of this section (see Section 27.2.12).

Furthermore, the types of fugitive emissions components that EPA proposed is inconsistent with the types of components in Subpart W, which varies by reporting sector, but generally includes: valves, connectors, flanges, open-ended lines, pressure relief valves, control valves, block valves, orifice meters, regulators, pumps, and other (Tables W-1A through W-7 to Subpart W of Part 98). This will cause confusion between the two programs. Also, this definition is inconsistent with the definition used in NSPS VVa, KKK and GGGa. VVa defines equipment as "*each pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart*" (§60.481a). Under KKK, EPA defined equipment as *"each pump, pressure relief device, open-ended valve or line, valve, compressor, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by this subpart"* (§60.631). NSPS GGGa defines equipment as *"each valve, pump, pressure relief device,* *sampling connection system, open-ended valve or line, and flange or other connector in VOC service. For the purposes of recordkeeping and reporting only, compressors are considered equipment*" (§60.591a).

Since this proposal includes separate closed vent system monitoring requirements for what is essentially a collection of fugitive emission components, *closed vent system* requires its own definition so that closed vent system requirements can stand alone and are not subject to duplicative compliance requirements as currently proposed when also included in this definition. More detailed comments that address this issue for closed vent systems are found in Section 15.0 Other equipment inappropriately included in this definition includes:

> *"access doors, …, thief hatches or other openings on storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters."*

The equipment list above that should be excluded from the definition are not fugitive components, but rather parts of systems or equipment such as the separators, pressure vessels, dehydrators, and heaters that may have fugitive components, and fugitive component monitoring would be applicable when required. Thief hatches have complexities of operation and design as discussed in Section 26.0, thief hatch monitoring is NOT needed for storage vessels with no closed vent system since thief hatch design and operation is not important with low emission tank that already vents to atmosphere. Including thief hatches with CVS eliminates unnecessary monitoring in §60.5397a.

Vents are not fugitive components because they are designed to vent and compressors are covered separately in Subpart OOOO and OOOOa. Instruments and meters are not defined and some are designed to vent.

The following language in the definition should be removed as it is confusing and sets conditions upon which it may or may not be a fugitive component which creates a circular conundrum for a monitoring plan:

> *"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."*

27.2.2 EPA Did Not Consider The Inconsistencies With State LDAR Programs (CO, PA, WY, TX, OH, Etc.). This Creates Duplicative And Potentially Conflicting Requirements With Little Environmental Benefit

Similar to the exemption for storage vessels under NSPS Subpart OOOO, §60.5365(e)(3), well sites or compressor stations subject to legally and practically enforceable requirements in an operating permit or other requirement established under Federal, state, local or tribal authority should be exempt from Subpart OOOOa LDAR requirements.

For example, the non-rule standard permit for oil and natural gas facilities in Texas[27] requires quarterly monitoring using M21 or optical imaging of valves and quarterly monitoring of pumps, compressor seals, and agitator seals without shaft sealing systems if the site fugitive emissions exceed 10 tons VOC/year.

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[27] http://www.tceq.texas.gov/assets/public/permitting/air/Announcements/oilgas-sp.pdf

However, proposed Subpart OOOOa requires OGI at least semiannually (and less frequently depending on percentage of leakers) for all components. Managing multiple LDAR programs for state and federal rules will create unnecessary compliance complexities for facilities trying to comply with the varying rules. Therefore, Subpart OOOOa should have allowances to rely on state LDAR programs in lieu of those in Subpart OOOOa if the state rules provide for equivalent work practices to reduce leak emissions.

The suggested exemption provided in the rule text edits at the end of this section (see Section 27.2.12) is consistent with the approach EPA used to quantify the cost effectiveness and the overall net benefits in the benefit-cost analysis for fugitives. Specifically, EPA excluded well sites in regulated states in their baseline and projections of affected oil and natural gas well sites in 2020 and 2025. The exclusion of well sites in regulated states has the effect of reducing both costs and emission reductions, so there is no net effect on cost effectiveness. However, the rule as proposed does not exclude well sites in regulated states from complying with OOOOa, which is not consistent with EPA's cost analysis. If well sites in regulated states are not exempt from Subpart OOOOa requirements, those affected well sites would incur higher costs to implement the additional LDAR requirements with little to no net emissions reductions. The resulting cost effectiveness would be higher than EPA estimated if those regulated well sites are not exempt. Therefore, EPA should exempt well sites subject to state LDAR requirements to be consistent with the approach used to estimate cost effectiveness. This will also prevent operators from having to develop a hybrid program based on the most stringent requirement between NSPS and state program requirements, which adds additional complexity to compliance.

In the Preamble, EPA requested comment on how to determine whether existing state requirements would demonstrate compliance with this federal rule. The table provided in Attachment F compares existing state LDAR requirements for Colorado, Pennsylvania, Wyoming, and Ohio to the proposed OOOOa requirements. Highlighted cells indicate where the proposed OOOOa requirements are more stringent than the state level requirements. API believes that any program (state, local, or even voluntary) that has the same conceptual elements (i.e. work practice standards for monitoring, recordkeeping and reporting) should be considered equivalent to OOOOa and therefore exempt from OOOOa LDAR requirements.

27.2.3 The 15 BOE Exemption In §60.5365a(i)(1) Recognizes Low Volume Production Being Lower Emission And Sensitive To Additional Cost Burden, But Is Not The Only Exemption To Consider

The 15 barrel of oil equivalent per day (BOE/day) exemption will generally not be useful for new sites since this level of production is consistent with a stripper well. Stripper wells represent wells near the end of their productive life not the beginning. Consequently, it would be rare for operators planning to construct well sites with initial production at this low level. The usefulness of this provision is at the end of a well's productive life as an off ramp to exempt being an affected facility much like being able to remove a control device at less than 4 tpy of storage vessel emissions or for sites that are modified and pulled into the rule. It would however be useful for modified or reconstructed sources.

Another exemption is based on GOR. EPA recognizes in this proposal that oil wells with little to no gas volumes should be exempt from REC requirements based on a low GOR of 300; this same GOR should be another threshold to exempt well sites from leak detection as well. If gas volumes are so low that gas gathering is uneconomic, it is not cost effective to have leak detection requirements for little to no methane or natural gas reductions. Since VOC reduction alone is not cost effective, the lack of natural gas production should be a factor in affected facility exemptions

Rule text change recommendation to reflect these comments are provided in Section 27.2.12.

27.2.4 Fugitive Emissions Do Not Correlate To Production

The proposed rule provides a threshold for an affected facility under §60.5365a(i)(1) "A well site with 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, is not an affected facility under this subpart." In the preamble, EPA solicited comment on the air emissions associated with low production wells, and the relationship between production and fugitive emissions, specifically on the relationship between production and fugitive emissions over time. EPA also solicited comment on the appropriateness of this threshold for applying the standards for fugitive emission at well sites, in addition to whether EPA should include low production well sites for fugitive emissions and if these types of well sites are not excluded, should they have a less frequent monitoring requirement.

Fugitive emissions do not correlate to production. A production rate gives no indication of the type or number of equipment that are located at the site. In addition, this exemption is irrelevant for new well sites which would not be economical to produce at 15 BOE/day. As stated in our comment above (see 27.2.3), this exemption should also be considered as an off-ramp to §60.5397a applicability or exemption in the rare event of a modification to a stripper well. However, API believes it more appropriate and would prefer that the rule be based on the process equipment located at the site rather than a low production rate since fugitive emissions are based simply on the number of components associated with the process equipment. As indicated in sections 27.2.6 and 0, API believes that sites with equipment configurations or component counts less than the model plants should be exempt from the LDAR requirements, as based on EPA's analysis, LDAR is not cost effective at sites with fewer equipment/components.

27.2.5 The Definition Of Well Site In §60.5430a Is Problematic And A New Definition For "Central Production Site" Is Needed

The proposed definition of "well site" includes both a well pad and other sites with process equipment that receives produced fluids from wells. The definition is problematic in that it can be interpreted to mean that all well pads connected to a tank battery or other centralized station can be aggregated as part of a single well site. This is unprecedented and appears to be an attempt to aggregate sites that are not otherwise contiguous or adjacent but instead functionally interrelated. This could lead to conflict with the Source Determination rule leading to potential permitting questions subject to variable interpretations. In Source Determination, courts have ruled against functional interrelatedness. In effect, EPA is applying Option 2 from the Source Determination proposal to define a source in NSPS. **It is inappropriate to aggregate sites.**

This erroneous definition change is being made to support the misconception that hydraulic fracturing increases fugitive emissions and constitutes a modification. The modification issue is discussed in more detail below in Section 0. The practical result of this error is that EPA's proposed definition of "well site" dissociates from the common sense and generally accepted and practically understood use of the term within industry. As well, tank batteries may or may not be tank batteries because of a false regulatory construct based on the activity at a distinctly separate surface site that has one or more wells. Additionally, the wellhead only exemption in paragraph (2) is rendered meaningless since aggregating separate surface sites into one means there will be no wellhead only well sites since wellhead only sites can produce to centralized tank batteries which would now be considered part of the wellhead only well site. EPA should instead consider a well site to be a distinct and separate surface site from a central processing site with no wellheads. The proposed definition change needs to be scrapped and either make no change to the original definition in Subpart OOOO or alternatively modify the definition as API recommends below in Section 27.2.12.

Another outfall of trying to define a well site other than in its generally accepted and common sense definition is that EPA assumes that any wellsite such as a wellhead only site produces to a central tank battery. This is not always true, there are other possibilities. A well could produce to a tank battery, a compressor station, or a tank battery combined with a compressor station, any of which may also happen to have one or more wells on the same surface site, making them well sites. Consequently, the collection of well sites that go to a central tank battery with no wells make the battery and the collection of well sites an aggregated single well site. But, if the central tank battery happens to include an onsite well, it is a separate well site, not an aggregated well site. These various operating scenarios complicate determinations of well site as proposed when a definition includes sites with no wells. This argues for each separate surface site to be evaluated independently for modifications without attempted aggregation.

As described in the previous paragraph, there are multiple centralized site configurations which complicate the applicability requirements in paragraphs §60.5365a(i) and (j). While the previous paragraphs discussed the issues with the definition of a "well site", a new definition is needed to more accurately account for centralized sites. For paragraph (j) API recommends the term "central production site" and "transmission compressor station" replace the use of the single term "compressor station". A central production site properly defined encompasses central gathering and boosting compressor stations, tank batteries, and combination tank batteries and compressor stations that have no wellheads located on the same surface site. Central production sites are located between a well site and natural gas processing plant or transmission pipeline. The recommended definition is found below at the end of in Section 27.2.12.

27.2.6 EPA Must Exclude Co-Located Midstream Assets From Well Sites

In the final rule, EPA must clearly exclude co-located midstream assets from the fugitive emission monitoring program for well sites. As proposed, EPA's broad definition of "well site" and "fugitive emission component" could be interpreted to subject midstream assets to fugitive emission monitoring requirements simply because they are located in geographic proximity to a production facility. Such an approach is inconsistent both with the way that the oil and natural gas sector operates and with the CAA. Upstream natural gas production and midstream gas gathering and processing are fully distinct and sequential portions of the natural gas sector supply chain. Appropriate clarifications and changes to the proposed rule need to be addressed so that co-located midstream assets are not inadvertently included in fugitive emission monitoring requirements designed for well sites.

Including co-located midstream assets in the fugitive emissions monitoring program for well sites is inappropriate for a number of reasons. First, equipment owned, operated, or leased by midstream operators is legally distinct from equipment owned, operated, or leased by upstream producers. Given their separate and distinct legal status EPA must establish separate requirements for upstream and midstream equipment. It is arbitrary and capricious to include some midstream assets in the fugitive emissions monitoring program simply because they are co-located within the footprint of a well pad site while excluding other midstream equipment that is located on a separate parcel of land.

API believes that the recommended definition changes discussed above in section 27.2.5 will partially help alleviate this problem. However, API recommends that EPA should also limit well site requirements to the equipment owned or operator by the well operator. API notes that more detail on this issue is provided in comments submitted by the Gas Processors Association (GPA), along with recommended regulatory text.

27.2.7 Only Sites With Major Equipment (Such As Separator, Heater, or Glycol Dehydrator) Should Be Subject. The Proposed Requirement To Exempt Sites With Only Wellheads Is Not Adequate

§60.5365a(i)(2) exempts well sites that only contain one or more wellheads. "*(2) A well site that only contains one or more wellheads is not an affected facility under this subpart.*" API agrees that a well site consisting only of wellheads should be exempt due to the small number of fugitive components. It would be overly burdensome with little gain in emission reductions to broadly require LDAR programs at sites without process equipment located at the well site.

Similarly, API believes that additional exemptions should apply. EPA's Model Plants used in the TSD are based on the following assumed equipment and component counts.

Table 27-1 EPA Model Well Site Equipment and Component Counts

	Assumed Equipment Counts		*Assumed Component Counts*	
Gas Well Sites	Wellheads	2	Valves	114
	Separators	2	Connectors	414
	In-line Heaters	1	OELs	14
	Dehydrators	1	PRVs	6
Oil Well Sites	Oil Wellheads	2	Valves	29
	Separators	1	Connectors	104
	Headers	1	OELs	1
	Heater/Treaters	1	PRVs	1

EPA uses these model well sites to establish the cost effective basis for the rule. Implementing LDAR is not cost effective at sites with component counts less than the model well sites. As discussed in Section 27.3.8, LDAR is not cost effective using the lower, unrounded estimates of component counts for the model well sites even without considering costs that EPA omitted from the cost effectiveness analyses. In addition, it is overly burdensome with little gain in emission reductions to broadly require LDAR programs at sites without process equipment located at the well site. API believes that any well site with equipment configurations or component counts less than the model well sites should be exempt from the LDAR requirements. This would exclude well sites with just wellheads, meter runs, pipeline risers, etc. and no production equipment, such as separators, heaters, and dehydrators.

27.2.8 Based On EPA's Estimates, LDAR Requirements For Oil Well Sites Are Not Cost Effective. Therefore, Oil Wells Should Be Exempt From The Subpart OOOOa LDAR Requirements

Similar to the proposed low producing well site exemption for fugitives under Subpart OOOOa, oil well sites should be exempt from the LDAR requirements. This is based on the costs, cost effectiveness, and benefits estimated for oil wells.

EPA's Levels of Reasonable Cost Effectiveness

While EPA does not establish a bright line that separates what they consider to be reasonable and unreasonable with regard to cost effectiveness, this proposal provides indications of levels that EPA clearly considers to be unreasonable. On page 56636 of the September 18, 2015 Federal Register notice proposal, EPA indicates: "In a previous NSPS rulemaking [72 FR 64864 (November 16, 2007)], **we had concluded that a VOC control option was not cost-effective at a cost of $5,700 per ton**." While EPA does not make an affirmation that is as clear-cut for methane, EPA's decisions establish a precedent. For quarterly OGI monitoring for well sites, EPA estimated the following cost effectiveness levels shown in Table 27-2.

Table 27-2 EPA's Estimated Cost Effectiveness With Savings ($/ton) for Quarterly OGI Monitoring at Well Sites

Single Pollutant[a]		Multipollutant[b]	
Methane	**VOC**	**Methane**	**VOC**
$3,521	$12,668	$1,761	$6,334

[a]Table 5-16 of the Background Technical Support Document.

[b]Table 5-17 of the Background Technical Support Document.

For this option, EPA determined that "we find that the cost of monitoring/repair based on quarterly monitoring at well sites using OGI is not cost-effective for reducing VOC and methane emissions under either approach." (80 FR 53363). Therefore, since EPA rejected this alternative with a cost effectiveness of $1,761 per ton of methane reduced, this clearly establishes that EPA believes that $1,761/ton of methane is unreasonable.

EPA's Cost Effectiveness Analysis for Oil Wells

In the evaluation of the fugitive leak regulatory alternatives for well sites, EPA made their decisions based on the weighted average cost effectiveness of oil wells and gas wells. EPA clearly recognized the difference in emissions potential between oil and natural gas wells, as they developed different model plants. Yet, without any justification or rationale, they ignored these differences and lumped oil and natural gas wells into one category and decided that the costs were reasonable to regulate both. However, as shown in Table 27-3, there were significant differences in the cost effectiveness of OGI monitoring for oil and natural gas wells. EPA must re-evaluate the LDAR program options separately for oil wells and gas wells and make decisions on the reasonableness of the costs independently.

As is evident in Table 27-3, the cost effectiveness varies significantly between oil and natural gas wells. All the cost effectiveness values for gas wells, based on EPA cost estimates, are below the reasonableness thresholds discussed above ($5,700/ton for VOC and $1,761/ton for methane).

However, for oil wells, all the cost effectiveness values, with the exception of the methane cost effectiveness using the multipollutant approach, are above these thresholds. For the following reasons, EPA cannot conclude that OGI monitoring is cost effective and must not finalize any LDAR requirements for oil well sites.

Table 27-3 EPA's Estimated Cost Effectiveness - With Savings ($/ton) for OGI Monitoring at Well Sites

Monitoring Period	Type of Well Site	Single Pollutant[a]		Multipollutant[b]	
		Methane	VOC	Methane	VOC
Semi-Annual	Gas	$587	$2,111	$293	$1,056
	Oil	$3,186	$11,460	$1,593	$5,730
	Weighted Average	$2,536	$9,124	$1,268	$4,562
Annual	Gas	$500	$1,799	$250	$900
	Oil	$2,824	$10,158	$1,412	$5,079
	Weighted Average	$2,243	$8,069	$1,121	$4,035

[a]Tables 5-15 (semiannual) and 5-14 (annual) of the Background Technical Support Document.
[b]Table 5-18 (semiannual) and 5-17 (annual) of the Background Technical Support Document.

The Multipollutant Approach Is Not Legal. As discussed in section 10.0, EPA's reliance on the multipollutant methodology is arbitrary and capricious because it is inconsistent with EPA's own "rational basis" test for determining whether regulation of an additional pollutant from a source category is appropriate. As EPA clearly states, under its "rational basis" test, the Agency must have a rational basis for regulating *each* "pollutant." *See* 80 Fed. Reg. at 56601. EPA's multipollutant approach is inconsistent with that test because it allows the Agency to find that regulation of multiple "pollutants" is reasonable where regulation of each pollutant individually would not be. Clearly the single pollutant cost effectiveness values are well beyond the levels EPA has determined to be unreasonable. However, even if EPA continues to consider this multipollutant approach, the points below demonstrate that LDAR at oil well sites is not cost effective under this illegal approach. Additional discussion of cost effectiveness is provided in Section 27.3, which expand further on costs that EPA did not even consider in their analyses.

Gas Streams at Oil Well Sites Have Lower Methane Content than the Representative Composition Used by EPA in Their Analysis. All of EPA's impacts analyses were conducted using a single representative gas composition.[28] For oil and natural gas production, this gas composition included 82.9% methane by volume. This methane content is relatively representative of the gas composition at gas well sites, but considerably higher than is present at oil well sites. In the same memorandum cited above, EPA also developed gas compositions for completions and recompletions at gas and oil wells. For oil wells, this composition included a methane content of 46.7% by volume. However, EPA elected not to use this composition in their analysis to evaluate the reasonableness of the costs of a program to reduce fugitive emissions from oil wells. Had EPA used this more appropriate gas composition, the lower methane content would result in lower methane emissions and lower methane emissions reductions. Using these these lower reductions would result in higher cost effectiveness values. For example, revising EPA's analysis for oil well sites to utilize a methane content of 46.7% by volume would result in methane cost effectiveness values of approximately:

- Single pollutant cost effectiveness values for methane of \$5,656/ton and \$5,013/ton for semiannual and annual OGI monitoring, respectively.

- Multipollutant cost effectiveness values for methane of \$2,828/ton and \$2,507/ton for semiannual and annual OGI monitoring, respectively.

This realistic adjustment moves these cost effectiveness values, including those determined based on the multipollutant approach, to well above the \$1,791/ton level that EPA determined was unreasonable in this rulemaking.

EPA Significantly Underestimated the Costs of an OGI Monitoring Program. As discussed at length in Section 27.3, EPA's cost analysis for an OGI monitoring program failed to consider many items that will significantly increase the cost. Table 27-5 provides a detailed item by item estimate of an annual OGI monitoring program based on API member companies that have actually implemented such programs. This analysis estimates the cost of an annual OGI monitoring program to be \$8,343 per year. This is almost seven times higher than the \$1,228 annual costs (with savings) estimated by EPA for an annual program. Even if EPA does not agree with all the adjustments to the cost estimate recommended by API, it is certain that the actual costs of a program would increase the small amount necessary to drive the multipollutant cost effectiveness for methane to greater than \$1,761/ton.

EPA's Benefits Analysis

In addition, the benefit-cost analyses performed by EPA also support the conclusion that oil well sites should be exempt. The benefit-cost analysis is an assessment of the overall impacts of the rule, taking into account the economic impact analysis and an analysis of the climate, health, and welfare impacts from the proposed rule. EPA projects both the total costs and total benefits (for methane, the benefits are

[28] Memorandum to Bruce Moore, U.S. EPA from Heather Brown, EC/R. *Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking*. July 2011.

associated with the avoided social cost of methane) for the first year the full rule is in effect (2020) and a later date to demonstrate how affected sources accumulate over time (2025). The net benefits for the target future dates represent the difference between the total benefits and costs.

Based on EPA's estimate of net benefits, even without considering unaccounted for cost elements (see Section 27.3.3) or the lower methane emissions (see discussion above), the benefit-cost analysis demonstrates that the net benefit is negative for 2020 and 2025 for oil well sites. The net benefits, based on EPA's analysis, are summarized below in Table 27-4 for oil well site LDAR requirements for 2020 and 2025. A negative net benefit means that the overall costs to industry for implementing the LDAR requirements for oil well sites is higher than the overall societal benefits from the emission reductions of methane. Therefore, the proposed LDAR requirements for oil well sites are not justified from an economic standpoint, and the burden to the industry is greater than the benefits accrued.

Table 27-4 Summary of EPA Cost Benefit Analysis for Oil Wells

EPA Estimates for Oil Well Sites	***2020***	***2025***
Benefits, $MM	$7.3	$51
Costs, $MM	$19.7	$119
Net Benefits, $MM	-$12.4	-$68

Conclusion and Recommendation

As demonstrated in the previous discussion in this section, the economics do not support the regulation of fugitive leaks at oil well sites. First, EPA cannot "hide" the unreasonable costs of an LDAR program for oil well sites by lumping them together with the impacts at gas well sites, where LDAR program appears to be cost effective. Even if EPA utilizes the multipollutant approach (which API maintains is not legal), very minor adjustments to EPA's analysis to more accurately represent oil well sites results in costs effectiveness levels for all metrics that are beyond the levels that EPA has determined in this rulemaking to be unreasonable.

Therefore, EPA must not finalize any LDAR requirements for oil well sites. In their analysis, EPA did not define the criteria they considered in developing model plants for an oil well site versus a gas well site. API believes that, for the purposes of the applicability of these fugitive leak components, the API gravity and gas-to-oil ratio (GOR) are characteristics that can be used to define these "oil" wells that must be exempted from these fugitive emissions LDAR requirements. API proposes that a well site that produces oil with either an API gravity less than 18˚ or a GOR less than 300 scf/bbl be exempted.

The recommended regulatory change to accomplish this necessary exemption is provided in Section 27.2.12.

27.2.9 Produced Water Injection Facilities Should be Exempt from the LDAR Requirements

Injection well facilities receive produced water that has been physically treated to remove liquid hydrocarbons and natural gas before arriving at the facility. For the following reason these facilities should not be included in the fugitive monitoring program:

They contain operations and activities associated with produced water delivery, storage, and injection.

These facilities are constructed to manage a producing field's water production.

Natural gas is not typically associated with these facilities.

There are limited liquid hydrocarbons present at these facilities. Thus, there are very limited emissions from the storage vessels therefore storage vessels vent to atmosphere and are not controlled.

Hydrocarbons are removed from the water prior to arriving at the injection well facility to avoid loss of revenue.

There is little to no environmental benefit in subjecting these injection well facilities to LDAR requirements and requiring additional resources which could be used for a better purpose. If EPA had considered the cost effectiveness of LDAR on injection well facilities, the results would show a net negative benefit. Therefore, injection well facilities should be excluded from the LDAR requirements. The recommended regulatory change for this exemption is provided in Section 27.2.12.

27.2.10 The Definition Of Modification For Leak Detection Under §60.5365a(i)(3) Is Flawed For Both Well Sites And Compressor Stations.

Well Site Modification

EPA has defined a modification for well site fugitives as follows in §60.5365a(i)(3)

"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."

Increasing production by drilling a new well or hydraulically fracturing an existing well does not increase the probability of a leak from an individual component and no new components result from these activities, thus the potential emissions rate does not change. EPA appears to agree, as there is no demonstration in this proposal, the TSD, or RIA that shows increased fugitive emissions from higher pressures. EPA's estimate of emissions simply uses the accepted method of component count × AP-42 factor.

The increased emissions from hydraulic fracturing are accounted for in the requirements for control devices and closed vent systems for storage vessels. Potential changes in pressure from hydraulic fracturing would only be on the components for the well head because components from the well choke or separator help to regulate the line pressure to that of the gathering system. Furthermore, for safety reasons, the components at the well head and down the line are rated for higher pressures beyond what wells and gathering systems will operate, and an increase in the pressure alone would not inherently impact the emissions from those components.

Compressor Station Modification

EPA has defined "modification: for compressor stations in §60.5365a(j):

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.

Here, EPA presumes that the addition of a new compressor at an existing compressor station would automatically increase the compressor station's emission rate and meet the definition of "modification". This is very often <u>not</u> the case – an operator may install a new compressor at an existing site to replace one or more existing compressors, which may even reduce emissions. In addition, an increase in compression capacity does not necessarily include a commensurate throughput and potential fugitive emission rate increase, it may simply be added for redundancy to increase operating reliability of the station. Throughput increases can also occur without increasing the number of compressors, if increases remain below the capacity of currently installed compressors.

Complicating matters, "new" means construction commenced after the proposal date. In this case construction refers to manufactured date. Since "new" compressors aren't new because of when they are installed but rather when they are manufactured, "new" compressors may be relocated to other sites when no longer needed at current sites to save incurring capital costs of purchasing a newly manufactured compressor. This may also be a "new" or existing rental compressor if not expected to be on location long enough to justify a purchase of a new or existing compressor. Consequently, if a capital expenditure occurs, it will generally only be when the "new" compressor is initially installed. Relocating a "new" compressor from one site to another is often an expense, but not a capital expenditure. Paragraph 60.5397a(j)(1) is then based on a flawed premise to presume that a site modification has occurred. The "new" compressor may already be subject to Subpart OOOOa requirements, but was installed without incurring a capital expenditure. Coupled with situations for adding compression that do not incur an emissions increase as described in the previous paragraph, no modification occurs, and it is inappropriate to presume otherwise.

Similarly, presuming a physical change that increases compression capacity increases emissions is also flawed. Increasing capacity doesn't necessarily mean an increase in throughput or an emissions increase in fugitive emissions. Capacity of one compressor may be increased so that another compressor can be permanently shutdown or relocated as part of a site optimization project which generally results in emissions decreases. In this case, a disincentive is presented in Subpart OOOOa by requiring a leak detection program for a project designed to decrease emissions, not increase.

Use of Modification in Other Rules

As with NSPS OOOO and NSPS KKK, it has historically been and should continue to be EPA's intent that triggering NSPS through "modification" is in fact a difficult threshold to meet, not an easy one. Here, however, EPA's proposed definition is overly inclusive and inappropriately relaxes the definition of modification.

The Clean Air Act Section 111(a)(4) defines a modification as follows - "The term ''modification'' means any physical change in, or change in the method of operation of, a stationary source which **increases the amount of any air pollutant emitted** by such source or which **results in the emission of any air pollutant not previously emitted**." [emphasis added]

Also §60.2 defines modification as: "Modification means 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."

The original definition of modification in §60.14 includes an increase in hourly emission rates. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere."

§60.14 require three important elements before an event qualifies as a "modification":

(1) a physical or operation change to an existing affected facility,
(2) that results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies, and
(3) for which a capital expenditure is required.

These elements establish the very high threshold necessary to demonstrate a modification has occurred, whereas EPA's proposal undermines these long-standing principles.

§60.14(e)(2) states that "*an increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility*" is not a modification. EPA has defined in this rule the affected facility as a "well site" and the definition of a "well site" does not include the well bore or reservoir that is being fractured. "*Well site means 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, or produced water from wells not located at the well site (e.g., centralized tank batteries).*"

Hydraulic fracturing is not a capital expenditure for the well site as it does not involve physical changes or changes to the operation of existing surface equipment. It is the process of "fracturing" the reservoir. A new well bore is subsurface and not part of the "well site" which is a surface site. Therefore, EPA should not consider the addition of a new well or hydraulically fracturing an existing well a modification for a facility for the purposes of LDAR.

Furthermore, other NSPS for fugitives (e.g., VVa and GGGa) define the affected facility by the process unit and requires a capital expenditure to be a modification to the process unit. VVa defines the affected facility as "*the group of all equipment within a process unit*" (§60.480a(a)). Equipment is defined as "*each pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart (§60.481a).*" VVa also states that "*Addition or replacement of equipment for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart*." VVa defines capital expenditure differently too giving a much higher B value of 12.5 vs. 4.5.

GGGa defines the affected facility as (§60.590a(a)):

(1) The provisions of this subpart apply to affected facilities in petroleum refineries.

(2) A compressor is an affected facility.

(3) The group of all the equipment (defined in §60.591a) within a process unit is an affected facility.

Under GGGa, equipment is defined as "Equipment means each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service. For the purposes of recordkeeping and reporting only, compressors are considered equipment." (§60.591a) Process Unit is defined as "the components assembled and connected by pipes or ducts to process raw materials and to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product. For the purpose of this subpart, process unit includes any feed, intermediate and final product storage vessels (except as specified in §60.482-1a(g)), product transfer racks, and connected ducts and piping. A process unit includes all equipment as defined in this subpart." (§60.591a) It states that "Addition or replacement of equipment (defined in §60.591a) for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart."

Recommendation

EPA's cost analysis was based on a model plant with certain component counts (554 for gas wells and 135 for oil wells). API recommends that the definition of modification be based on the addition of certain large equipment such as a separator, heater, or dehydrator, as used for the model plant count basis, to be consistent with the basis of the cost analysis and other fugitive rules. Furthermore, replacement of existing equipment should not be considered a modification to the facility since it would not increase the component count which is what the cost estimate is based on.

27.2.11 Components at Enhanced Oil Recovery Fields Must Be Exempted from the Fugitive Emissions Standards in Subpart OOOOa

Background on Enhanced Oil Recovery

Crude oil development and production in U.S. oil reservoirs can include up to three distinct phases of recovery: primary, secondary, and tertiary recovery. During primary recovery, the natural pressure of the reservoir or gravity drive oil into the wellbore, combined with artificial lift techniques (such as pumps) which bring the oil to the surface. Secondary and tertiary recovery techniques, which are often referred to as Enhanced Oil Recovery, or EOR, extend a field's productive life generally by injecting water, gas, heat, or chemicals to displace oil and drive it to a production wellbore.

Examples of secondary EOR techniques includes water floods, and tertiary EOR techniques includes thermal recovery floods (e.g., steam), and gas injection floods (e.g., CO_2). These EOR oil recovery techniques are used in oil fields to improve oil recovery after reservoir gas has been produced, and reservoir pressure and primary oil production are very low (e.g., no reservoir energy). In addition, the reservoir gas is artificially or mechanically changed with inert gases. Inert gases include nitrogen, hydrogen sulfide (H_2S), and carbon dioxide (CO_2). These inert gases may be required to be gathered and processed through specialty gas plants prior to sale. EOR is commonly found in older oil fields.

Water flooding is used to increase oil production by injecting a substantial amount of water into the oil reservoir rock voidage and increasing reservoir pressure. The injected water displaces the oil and carries the fluids to production wells. Water to oil ratios can be greater than 90%. In some EOR water floods, H_2S and other inert gases are generated in the reservoir. As a result, surface production equipment (i.e., plant) must be designed to handle high volumes of water and 3-phase fluids, and contain the potential "sour" and inert/contaminated gases for personnel safety reasons.

Thermal flooding is used to improve heavy oil recovery by injecting steam into the oil reservoir. Heavy oil has low viscosity, gas to oil ratio (GOR), and typically an API Gravity <18. The steam increases the heavy oil temperature reducing the viscosity allowing the oil to be produced from the well via artificial lift. The thermal surface equipment is designed to manage high volumes of water, heat the water, inject the steam, produce the hot oil, generally 2-phase separation of the fluids, and contain the low volumes of potential "sour" and contaminated gases for personnel safety reasons. Steam floods can generate substantial concentrations of hydrogen sulfide.

Gas injection (CO_2) flooding is used to improve oil recovery by injecting a miscible gas and water into the oil reservoir. The miscible gas, water, and increased reservoir pressure improves oil recovery and fluid sweep. Gas and water are injected into wells and the oil, water, and contaminated inert gas is recovered from production wells. The surface equipment is designed to manage high volumes of water, high pressure gas (e.g., CO_2 as a liquid), injection system, production/gathering system for the multi-phase liquids, high and low pressure separation of the fluids, and greater than 30% inert and potential "sour" gases. Due to the displacement characteristics of CO_2 and Immediately Dangerous to Life or Health (IDLH) for H_2S, the surface equipment is designed for personnel and public safety reasons.

EOR Gas Gathering Systems and Plants are designed to transport and process the volumes and EOR recovered gases that include CO_2, N_2 and H_2S.

EPA Did Not Consider EOR Operations in Their Rulemaking

Oil production fields that utilize EOR have very different gas stream compositions and characteristics from the types of operations that EPA evaluated in the development of the proposed NSPS subpart OOOOa (and the CTG). These differences have a significant impact on the VOC and methane emissions. EPA's model plants and representative gas compositions used to evaluate the impacts that drove the regulatory decisions are derived from gas fields and natural gas processing plants, and they do represent EOR operations. For example, EPA used a single nationwide gas composition to estimate fugitive emissions from all sources.[29] This gas composition includes 3.2% inerts by volume. In the limited time available during the public comment period, API did a very brief survey of member companies and found that the inert content of the gas streams in EOR fields ranged from 14% to over 64% by volume, depending on the type of EOR technique used. Obviously this significant difference in gas composition will have a tremendous impact on the baseline VOC and methane emissions and the emission reductions achieved by the fugitive emission requirements. And without a doubt, the decisions made by EPA regarding the reasonableness of the cost in relation to the VOC and methane emission reductions would not be applicable to EOR fields.

From a careful review of the background information for proposed NSPS subpart OOOOa, it appears that EPA did not consider EOR fields in any manner. A search of the September 18, 2015 preamble, the Background Technical Support Document, and the Regulatory Impact Assessment did not find a single mention of "enhanced oil recovery."

However, while EPA did not consider EOR operations in this rulemaking, clearly they are aware of these operations and the emissions. Subpart W of the GHG reporting program requires the reporting of GHG emissions from EOR operations and defines *enhanced oil recovery as follows:*

> *Enhanced oil recovery* (EOR) *means the use of certain methods such as water flooding or gas injection into existing wells to increase the recovery of crude oil from a reservoir. In the context of this subpart, EOR applies to injection of critical phase or immiscible carbon dioxide into a crude oil reservoir to enhance the recovery of oil.*

Further, Subpart W requires reporting of GHG emissions from two specific EOR operations - EOR injection pump blowdown and EOR hydrocarbon liquids dissolved CO2. Note that in both instances EPA only requires the reporting of CO2, indicating EPA's expectation that little or no methane would be emitted. Therefore, not only was EPA aware of these EOR operations, EPA had available GHG data from the GHG reporting program that they could have utilized. But they chose to totally ignore this segment in the industry in all technical evaluations.

Conclusions and Recommendation

Following are the conclusions regarding EOR.

- EOR fields are very different from the types of operations EPA evaluated in the development of the proposed NSPS Subpart OOOOa requirements.
- The gas streams at EOR fields have an inert gas content radically higher than the representative gas composition used by EPA in the evaluation of control options for subpart OOOOa.
- These differences will have a significant impact on the VOC and methane baseline emissions, emission reductions, and cost effectiveness.
- Based on the fact that EPA did not once mention EOR in the preamble or background documents, it is clear that there was no evaluation conducted for this segment of the oil and natural gas industry.

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[29] Memorandum. Brown, Heather P, EC/R Incorporated to Moore, Bruce, EPA/OAQPS/SPPD. Composition of Natural Gas for use in the Oil and Gas Sector Rulemaking. July 28, 2011.

Given these facts, EPA must include an exemption for EOR operations from the fugitive leak requirements in NSPS subpart OOOOa. Recommended regulatory changes are provided in Section 27.2.12.

If EPA elects not to incorporate the changes suggested by API above, EPA cannot require EOR fields to comply with the fugitive leak requirements in NSPS subpart OOOOa without a full evaluation of emissions, controls, costs, and impacts specific to these unique operations in the oil and natural gas industry and a separate proposal that provides the rationale for any rulemaking for EOR operations. If EPA chooses to follow the path, API will work with EPA to gather accurate information for their analysis.

27.2.12 Recommended Rule Text and Definition Revisions Based on Comments in this Section

§60.5365a(i) Except as provided in § 60.5365a(i)(1) through (i)(~~2~~5), the collection of fugitive emissions components at a new, modified, or reconstructed well site, as defined in § 60.5430a, is an affected facility.
1) A well site with 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 or for any 12 consecutive month period after startup of production, is not an affected facility under this subpart.
(2) Any well site or process unit with a GOR less than 300 scf/bbl during the first 30 days of production or for any 1 year period after startup of production is not an affected facility.
(3) Any oil well site requiring mechanical artificial lift such as a rod pump or submersible pump with no associated gas gathering system is not an affected facility.
(4) Well sites with a legally and practically enforceable leak detection and repair requirement in an operating permit or other enforceable requirement established under a Federal, State, local or tribal authority are not affected facilities in this subpart.
(~~2~~5) A well site with one or more wellheads that does not ~~only contain~~ include installation of at least one of the following: a separator, heater, or glycol dehydrator ~~one or more wellheads~~ is not an affected facility under this subpart.
(6) A well site that produces oil with either an API gravity less than 18˚or a GOR less than 300 scf/bbl is not an affected facility under this subpart
(7) An EOR wellsite is not an affected facility under this subpart
(~~3~~8) For purposes of § 60.5397a, a ''modification'' to a well site occurs when an additional well head, separator, heater, or dehydrator is installed.
~~(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.~~

§60.5365a(j) The collection of new, modified, or reconstructed fugitive emissions components at a central production site or transmission compressor station site, as defined in §60.5430a, is an affected facility. The collection of fugitive emissions components at a compressor station or central production site in an EOR field is not an affected facility.
(1) Central production sites and transmission compressor station sites with a legally and practically enforceable leak detection and repair requirement in an operating permit or other enforceable requirement established under a Federal, State, local or tribal authority are not affected facilities in this subpart.
(2) For purposes of § 60.5397a, a ''modification'' to a compressor station or central production site occurs when:

(i) An additional new, modified, or reconstructed compressor is installed at an existing transmission compressor station or central production site that results in an increase in emissions of a compressor station or central production site; or
(ii) A physical change is made to an existing compressor at a transmission compressor station or central production site that increases the ~~compression capacity of~~ emissions at the transmission compressor station or central production site.
(iii) An additional new, modified, or reconstructed separator, heater, or dehydrator is installed at a central production site.

§60.5430
Enhanced oil recovery (EOR) means the use of certain methods such as water flooding or gas injection into existing wells to increase the recovery of crude oil from a reservoir.

Recommended definition changes:

Central production site means one or more contiguous surface sites with no wellheads and with a collection of either one or more gathering or boosting natural gas compressors, one or more crude oil or condensate storage vessels, or both that process crude oil or natural gas and located between a well site and natural gas processing plant or natural gas transmission line, but is not co-located with a well head.

Fugitive emissions component means each pump, pressure relief device, open-ended valve or line, valve, flange or other connector that is in VOC or natural gas service at a well site, central production site, or transmission compressor station but not including a natural gas processing plant process unit. ~~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 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.~~

"Well site means one or more contiguous ~~areas~~ surface sites that are ~~directly~~ constructed ~~disturbed during~~ for the drilling and subsequent operation of an oil or natural gas well, and any~~affected by~~ production facilities directly associated with any oil well or natural gas well. ~~or injection well located on a 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, or produced water from wells not located at the well site (e.g., centralized tank batteries).~~

27.3 Impacts, Emissions, Costs

27.3.1 EPA Did Not Consider Key Costs To Industry In Assessing The Cost Effectiveness Of Leak Detection Requirements Proposed

In its cost analysis for the proposed control strategy for fugitive emissions, EPA did not adequately capture all of the costs associated with implementation of such a program. Specifically, in the cost-effectiveness evaluation, EPA underestimated the costs associated with:

- Conducting leak surveys
- Completing repairs, and
- Maintaining the required recordkeeping, including the costs of developing and maintaining the corporate and site-specific monitoring plans.

Further, EPA did not include several aspects beyond the cost of the actual survey work in its cost analysis, including:

- Training of personnel
- Travel time and costs
- Equipment maintenance (e.g. monitoring device calibration)

The following sections expand on each of these topics in more detail and API provides revised costs that are more representative of actual costs anticipated to comply with the proposed rule. Utilizing the more representative costs along with EPA's current estimates of emission reductions expected from the rule, the cost effectiveness of the proposed semi-annual OGI monitoring increases from EPA's estimate of $2,230 per well site to over $6,400 per site. As such, the Well Site Program Weighted Average cost effectiveness values (under a Multi-pollutant Method) would increase significantly beyond the already marginal values of $1,384/ton of methane and $4,979 per ton of VOC.

> **When the full costs of monitoring are considered, the leak detection program proposed is not cost effective for either methane or VOC.** This finding is based solely on corrected costs and does not reflect any changes to the assumed emission reductions, which API believes have been overstated as well. **[Emphasis added]**
>
> **At a minimum, API recommends OGI-based surveys be no more frequent than an annual frequency for any affected sources.**
>
> The exception to this is oil wells. As discussed above in section 27.2.8, there is no scenario where oil wells are cost effective. EPA should totally abandon the regulation of fugitive emissions at oil wells.

27.3.2 EPA Underestimated The Costs Of The Leak Survey And Leak Repairs In The Cost-Effectiveness Evaluation

In the cost estimation for implementing the LDAR requirements under Subpart OOOOa, EPA underestimated the cost of conducting a leak survey at the model well site. Although EPA estimated the model plant to consist of 2 wells per well site, they used cost data representing an OGI leak survey conducted by a contractor for a single well per well site ($600/single well battery[30]) as the basis of the leak survey costs. The cost of the survey based on the reference document would be higher than the value used in the analysis that represents a single well site ($600/single well battery) and lower than the value provided for a multiple well site ($1,200/multiple well battery) that represents on average 5 wells per site. A better estimate based on the reference document used would be a linear scaling between the given cost range which would result in an estimate of $720/model well site, representing 2 wells per well site. EPA also did not include any administrative costs for managing leak surveys conducted by contractors, as indicated in the reference document.

27.3.3 Many Additional Aspects Beyond The Cost Of The Actual Survey Are Not Considered By EPA And Should Be Included In Cost-Effectiveness Evaluation (E.G., Training, Monitoring Device Calibration, Travel Costs, Etc.)

The start-up cost of a major monitoring program involves many costs not associated with the routine recurring costs of the regular survey, such as program design and set up. EPA's cost analysis also failed to consider costs associated with training, monitoring device calibration, data management, and transportation. These are significant costs and should be part of EPA's assessment of the costs of the proposed requirements.

API surveyed companies conducting voluntary LDAR programs and compared these costs to EPA's model well site costs for annual LDAR. EPA's well pad model plant costs for semi-annual OGI LDAR surveys. Using EPA's cost spreadsheet for OGI well pad costs posted to the docket,[31] API added or updated costs based on company information. API's cost estimate used the same assumptions as EPA's where company data were not available.Key differences in the costs include the following:

- EPA included the cost of a M21 monitoring device ($10,800), but excluded the cost of the data collection system. EPA's separate cost estimate for conducting M21 LDAR includes a cost of $14,500 for a data system in conjunction with the M21 monitoring device. It is not clear why EPA excluded this cost from the OGI LDAR estimate.
- EPA's estimate for developing monitoring plans does not indicate if it is for the corporate level plan, site level plans, or both. EPA's estimate is approximately one-half the cost provided by companies with voluntary programs.
- EPA's estimate of recordkeeping costs does not account for the need to purchase or expand a data collection system to store all the information associated with an ongoing LDAR program. EPA also does not consider the need for a data analyst to manage the information.
- EPA's costs do not consider the purchase of OGI equipment (~$100,000 per unit), annual calibration of each OGI unit, or the training required to operate each unit.
- EPA's costs do not consider travel to and from each site to conduct the semi-annual surveys and for additional travel to repair and resurvey components when the repair cannot be completed immediately following the survey.

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[30] Carbon Limits. *Quantifying cost-effectiveness of systematic LDAR Programs using IR cameras.* December 24, 2013. Available at http://www.catf.us/resources/publications/files/CATFCarbon_Limits_Leaks_Interim_Report.pdf.
[31] CTG_Section_9_OGI_Well_Pad_Model_Plant_Costs_7-7--2015.xlsx

- EPA assumed a cost of $2.00 to resurvey repaired components. This cost implies the use of soap bubbles under Section 8.3.3 of M21 to determine if the leak has been repaired. However, as written under §60.5397a (j)(2)(ii)(A), the proposed rule does not specify that soap bubbles can be used to determine if a leak is repaired [§60.5397a (j)(2)(ii)(A) - *A fugitive emissions component is repaired when the M21 instrument indicates a concentration of less than 500 ppm above background.*]. API's cost estimate for resurveying to determine if a leak is repaired is based on determining if the concentration is less than 500 ppm above background.

The following table compares cost information for semi-annual OGI LDAR surveys and a 10,000 ppm leak definition based on data from companies conducting voluntary LDAR versus EPA's cost assumptions. Yellow highlighted cells indicate where costs are different and costs that EPA did not include in their analysis. Overall, API cost data indicate slightly lower well site costs ($1,590 based on API estimates compared to $2,096 from EPA's estimate as shown in Table 24-6). However API's estimate includes recurring annual costs that were neglected in EPA's estimate and significantly higher company level costs. The resulting total annual cost estimate from API member companies is almost three times higher than EPA's estimate.

Table 27-5 Comparison of Monitoring Costs – One Time Company Level Costs

Item	API Annual Total Cost ($)	EPA Annual Cost ($)	Comment
One-Time Company Level Costs			
Read rule and instructions	$231.20	$231.20	Cost based on hours from PES Memorandum
Development of Equipment Leaks Monitoring Plan - Corporate Plan	$7,200.00	$3,468.00	API members estimate $7,200 to develop the initial corporate monitoring plan. EPA estimated cost based on average number of people and hours from PES Memorandum
Initial Activities Planning	$1,849.60	$1,849.60	EPA cost based on hours from PES Memorandum
Notification of Initial Compliance Status	$1,271.60	$1,271.60	Assumes that 1 hour is spent to prepare the notification for each well site for 22 well sites
FLIR Monitoring - Cost of OGI Equipment	$95,000	Excluded from EPA's analysis	API survey responses ranged from $90K-100K. API estimate conservatively assumes just 1 device is purchased.
FLIR Monitoring - Cost of Data Management System	$225,000.00		API survey responses ranged from $200K-250K
FLIR certification Training	$2,000.00		API estimate conservatively assumes only one person is trained
M21 Monitoring and Data Collection System	$10,800	$10,800	EPA estimate includes cost of M21 monitoring device ($10,800) but excludes the cost of the data collection system ($14,500) that was assumed for M21
First Year Total Hours and Cost per Company	*$343,352*	*$17,620*	Sum of total company costs above
First Year Total Hours and Cost per Well Site	*$15,607*	*$801*	Assumes company owns 22 well sites

Table 27-6 Comparison of Monitoring Costs – Annual Costs

Item	API Annual Total Cost ($/yr)	EPA Annual Cost ($/yr)	Comment
RECURRING ANNUAL COSTS			
Annual Training	$2,000.00	Not included	API estimates for annual training ranged from $1,000 to $5,000. Conservatively assumed $2,000/yr
Data Analyst	$24,000.00	Not included	API estimate based on 10% resources of existing data analyst duties
Annual FLIR Device Calibration	$4,000.00	Not included	API estimates ranged from $3,000 - $5,000/camera. Conservatively assumed just one device is needed.
Annual transportation costs	$20,000.00	Not included	Per basin cost. API estimate assumes one basin requires 15,000 miles travel annually. Includes fuel and maintenance. Does not include the cost of purchasing a vehicle.
Recurring Annual Costs per Company	*$50,000.00*	*Not Included*	Sum of recurring annual costs above
Recurring Annual Costs per Well Site	*$2,272.73*	*Not Included*	Assumes company owns 22 well sites
Well Site Level Costs			
Subsequent Activities Planning	$63.05	$63.05	Based on hours from PES Memorandum. Total cost of planning divided by total number of well sites per company
Development of Site-specific Monitoring Plan	$120.00	Not Included	API estimate assumes 2 hours per site to develop the proposed site-specific monitoring plans
FLIR Survey cost	$462.40	$1,200.00	EPA cost from CL Report (outside contractor, well pad, $600 per survey). API estimate assumes 1 person and 4 hours to survey a well site using FLIR. Includes travel time.
Repair Cost	$597.48	$597.48	Assumes 1.18% or 4 total leaks found per survey, 3 fixed online (3 * 0.17 hours *$66.24/hr) and 1 fixed offline (1 * 4.0 hours * $66.24/hr)
M21 Resurvey Costs	$115.60	$4.00	EPA's resurvey costs assume cost of $2.00 per component for offline component repair. API's resurvey cost assumes 2 hours are required to travel to/from the site and resurvey the fixed component.
Annual Report	$231.20	$231.20	Assumes that 4 hours are spent to prepare the annual report for each well site and includes storing/filing of records
Cost per Well Site (Well site level costs only)	*$1,590*	*$2,096*	Sum of well site level annual costs
Annual Cost per well site with Amortized Capital Cost	***$6,476***	***$2,230***	**Includes first year costs per company site from table above, cost amortized over 8 years at 7% interest**

27.3.4 EPA Did Not Account For The Limited Availability Of Trained Personnel And Equipment To Complete Monitoring

In the Preamble, EPA indicated they were co-proposing monitoring surveys on an annual basis at the same time soliciting comment and supporting information on the availability of trained OGI contractors and OGI instrumentation to help evaluate whether owners and operators would have difficulty acquiring the necessary equipment and personnel to perform a semi-annual monitoring and, if so, whether annual monitoring would alleviate such problems.

Many third party LDAR companies exist that perform regulatory work for LDAR in downstream portions of the petrochemical industry. However, most API companies that have implemented voluntary LDAR programs have performed their work internally with their own personnel. These companies took considerable time to train their initial core staff and required in many cases more than a year to have such a program fully operational.

Based on discussions with both OGI Instrument manufacturers and trainers, there is likely to be an initial delay in providing OGI instruments and training to meet demand once OOOOa is promulgated. EPA should provide an initial compliance period of 1 year after publication of the final rule in the Federal Register to allow LDAR detection equipment manufacturers and training organizations to meet the initial demand for equipment and training.

As well, a backlog of sites constructed between the proposal date and 60 days after the promulgation date will exist that will take time to develop any required monitoring plans in the final rule, in addition to needing time to smoothly implement a monitoring program which includes procurement of crews, equipment, and training as described above.

API requests a one-year plus 60 days phase in period from the promulgation date for compliance with the LDAR requirements, as EPA provided under §60.5370 by setting the compliance date to the later of October 15, 2012 or startup, and in defining affected facilities under §60.5360 relative to August 23, 2011. In the Response to Comments for OOOO, EPA indicated that the one-year phase-in was necessary to provide time for operators to have time to establish the need for control devices, procure and install devices. For similar reasons, a one-year phase in should be provided for the LDAR requirements to allow operators time to purchase monitoring devices, conduct training, and establish protocols.

27.3.5 EPA Did Not Consider Impacts Of Travel To/From Sites By Trained Personnel

Oil and natural gas production operations, gathering and boosting facilities, as well as transmission and storage compressor stations are geographically dispersed. Costs and impacts need to consider the time associated with traveling to and from sites, vehicle and fuel costs, and resulting vehicle emissions to conduct recurring LDAR at all new or modified well sites or compressor stations. A company may have a third party group or specific in-house person doing the OGI monitoring that is different from the person doing the repairs. Although the majority of leaks are repaired when detected, there would be additional driving costs and impacts for leaks that cannot be repaired immediately and for conducting the resurvey after leaks are repaired.

According to survey data provided by 9 companies subject to Colorado Regulation 7, the average annual number of miles driven per basin for leak detection monitoring is 28,000, and the average annual transportation cost per basin is $34,785. API members conducting voluntary LDAR programs indicated an average of 15,000 miles traveled per basin, with an average annual cost of $21,000 per basin. These costs do not include purchasing additional vehicles to accommodate the required travel. Neither transportation costs nor costs for purchasing additional vehicles were included in EPA's evaluation of cost effectiveness.

27.3.6 Recordkeeping Costs Are Significantly Underestimated

The Colorado Regulation 7 record keeping requirements are not as stringent as the proposed Subpart OOOOa requirements. Based on survey data provided by 9 companies subject to Colorado Regulation 7, the average record keeping cost per basin is $188,125 with a reoccurring average annual cost of $39,444. That represents 41% of the average annual survey cost per basin.

Companies conducting voluntary LDAR surveys estimate their recording keeping costs at $60,000. Additionally companies that maintain a copy of OGI records estimate the data storage burden to be approximately 102 MB per survey per well. These costs represent approximately 26% of the average annual recurring LDAR costs per basin.

27.3.7 EPA Significantly Underestimated The Costs Of Developing And Maintaining The Corporate And Site-Specific Monitoring Plans

§60.5420a lists the notification, reporting, and recordkeeping requirements under the proposed rule. §60.5397a(b) requires that companies develop both corporate-wide and site specific fugitives emissions monitoring plans with the alternative of doing a site specific plan with elements of both the corporate-wide and site specific fugitives emissions monitoring plan requirements. EPA did not fully evaluate the complexities or the costs for developing and maintaining the proposed requirements in §60.5397a(c) and (d).

EPA has not included in the cost effective analysis for leak detection and repair any of the significant costs for developing and maintaining both a corporate-wide and site specific plan for every well subject to NSPS OOOOa, particularly with respect to EPA's expectation that component counts are to be included in the monitoring plan. The cost estimate of $3,468 for the monitoring plan is greatly underestimated considering the great amount of detail required for the 2 different plans.

API member companies estimate the cost for developing a corporate monitoring plan to be $7,200, and the cost to develop each site-specific monitoring plans to be $120. Annual recurring costs to keep the plans up to date are estimated to range from $1,000 to $3,000.

To count and tag components at a compressor station, costs approximately $10,000. In a study performed by an API member company which compared three basic leak detection methods: Audio, Visual, and Olfactory (AVO), OGI, and M21. Because M21 was already being conducted, the additional cost of component counts was $15 to $58 per site. However, if done in conjunction with an OGI survey, the cost would be substantially higher. API members estimate a cost of $120 per well site to develop an initial component count (excluding travel costs), and a recurring annual cost of $60/site.

In addition, EPA provided no provision for an area-wide monitoring plan. §60.5397a(b) requires that companies either have a corporate-wide fugitive monitoring plan or a site specific monitoring plan. EPA provides no other options such as area wide plans for an operations area or basin. However, the information required in each plan under §60.5397a(c) is so detailed and specific, it will make it very difficult to write a plan that covers the various pieces of information for each separate area such as:

Technique for determining fugitive emissions.

- The manufacturer and model number of the fugitive emissions detection equipment to be used. – Different equipment may be used in each area and over time depending if done internally or by a contractor.
- Procedures and timeframes for identifying and repairing fugitive equipment components from which fugitive emissions are detected. This will vary based on whether leak detection is done internally or by a contractor and by area.

- Procedures and timeframes for verifying fugitive emission component repairs. This will vary based on whether leak detection is done internally or by a contractor and by area
- Verification of the optical gas imaging equipment - Different equipment may be used in each area and over time depending if done internally or by a contractor.
- Procedures for determining the maximum view distance from the equipment – Each area may have different facility designs such as enclosed portions of the facility due to cold weather and physical locations such as on sides of cliffs that could limit or constrain the viewing distances.
- Procedures for conducting surveys – May vary by area or whether it is being done by contractors or internally.
- Training and experience needed prior to performing surveys – May depend on the equipment being used or whether the surveys in the area are being done internally or by contractors.
- Procedures for calibration and maintenance – Will vary based on the various equipment used by the area or contractors.

In some locations a company may choose to use contract services and other areas the same company may choose to conduct the surveys with internal staff. In addition, the variations in the development plans for different production areas may dictate different monitoring approaches. For example, an old declining field in one part of the country may have no sites or only a few sites subject to NSPS OOOOa which may require a company to handle the program differently than in another part of the country where they are drilling 30 wells or more a year that would be subject to NSPS OOOOa.

The proposed requirement for site-specific monitoring plans, including the requirement to specify a walking path for each site, is unnecessary and the requirements are onerous. Many times production areas do not have site maps developed for each site. Development of a sitemap would be solely for this rule. The cost of developing site maps for every site was not included in the cost evaluation for LDAR. Furthermore, the requirement to specify a walking path for each site is unnecessary for oil and natural gas well sites and compressor stations. The person conducting the survey must be trained and have the knowledge and ability to use the monitoring device.

The elements required in both plans are extensive, requiring a great amount of detail with no added benefit. EPA should not require both plans. Furthermore, it is unnecessary for the plan to require many of the detailed information EPA is requesting for the site specific plans since these are small, dispersed, unmanned well sites and compressor stations. EPA should allow companies to create area monitoring plans in place of site-specific plans or as an option for corporate wide plans. Proposed rule revisions to address these issues are provided in Section 27.3.11.

27.3.8 EPA Overstated The Baseline Emissions And Emission Reductions

As discussed above, EPA significantly underestimated the costs of the proposed LDAR requirements. To compound the problem, EPA overestimated the baseline emissions and emission reductions, which causes the cost effectiveness estimated by EPA to be lower than actual conditions.

One manner in which EPA overestimated the emissions is in their approach for estimating component counts for the model plant gas and oil well sites. EPA rounded up the average counts of major equipment per well site, as well as the number of wells per well site. The effect of rounding up the wells per well site and the major equipment per well site is an overstatement of the baseline emissions as follows:

Gas well sites: Baseline emissions decrease from EPA's estimate of 4.54 tons CH_4/yr/well site to an unrounded estimate of 3.18 tons CH_4/yr/well site, or a 30% reduction in methane baseline emissions and corresponding emission reductions.

Oil well sites: Baseline emissions decreased from EPA's estimate of 1.09 tons CH_4/yr/well site to an unrounded estimate of 0.70 tons CH_4/yr/well site, or a 36% reduction in methane baseline emissions and corresponding emission reductions.

27.3.9 API Members Find That Recurring LDAR Has A Diminishing Return

EPA assigned an emission reduction of 60 percent to semiannual monitoring survey and repair frequency and 40 percent to annual frequency, consistent with the reduction levels used by the Colorado Air Quality Control Commission in the initial and final economic impacts analyses and has also solicited comment on the approach. There is confusion between rulemaking presented by USEPA and Colorado on the origin of the 40, 60, and 80 percent emission reduction assumptions for tank OVI monitoring. Neither agency clearly substantiates the basis of their assumptions. In addition, EPA unilaterally changed the data from Colorado without justification. EPA should be required to produce the basis for these assumptions for industry review.[32]

Additionally, on page 56635 of the preamble, EPA solicited 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. API members find that recurring LDAR has a diminishing return [currently semiannually in proposed §60.5397a(g)]. The first survey identifies and corrects most of the leaks, but significantly fewer leaks are identified in subsequent surveys.

The Colorado Regulation 7 data reduction assumptions are based on an assumption that annual inspections will yield an annual leaking component rate of 1.18%, 1.77% for facilities with quarterly inspection and 2.26% for facilities with monthly inspection schedules. These assumptions were based on the chemical manufacturing industry (Subpart VV) and do not fit with the LDAR data observed in the upstream oil and natural gas industry. API companies conducting voluntary LDAR programs have observed much lower initial leak rates, ranging from 0.18% to 0.84% leaks for annual LDAR.

Survey data provided to API by companies subject to Colorado Regulation 7 enabled a comparison of the percent of components leaking for different leak survey frequencies (first time, then quarterly or monthly advanced instrument monitoring mechanism (AIMM) surveys). Overall, the percentage of components leaking were less than 1% from the initial survey and then decreased with subsequent re-survey. In the first quarterly AIMM survey, on average 0.88% of components were found leaking. In the second quarterly survey, the percent of components counts leaking dropped to roughly half at 0.38%. The monthly AIMM survey showed the same trend, with the initial survey finding 0.70% components leaking and subsequent monthly surveys decreasing to 0.17% in the 5th month. **Note, that although the leak finds decreased with subsequent surveys, the cost of each survey remained the same.** The $/ ton control provided by the EPA does not reflect the dramatic decrease in the percentage of leaking components over time with subsequent surveys.

From a separate analysis, an annual voluntary OGI survey involving 3,300 wells and 63 compressor stations, showed a 25% leak reduction at production sites and a 35% leak reduction at compressor stations in year two of an annual monitoring program. Based on HiFlow emission measurements and the

[32] Colorado references EPA has a source for their assumptions, while EPA has referenced Colorado's analysis for the basis of the proposed rule language in the preamble. Cost-Benefit Analysis for Proposed Revisions to Colorado Air Quality Control Commission Regulations No. 3 and 7 (February 7, 2014),

assumption that leaks would have emitted gas for 365 days, emission reductions per well in year one of the annual survey was 148 thousand cf or 449 scf/ well. In year 2 of the annual survey at production sites, there was a leak count reduction of 25% and a corresponding emission reduction of 25% compared to the initial survey year. For midstream compressor stations, the emission reduction volume was 204 thousand cf or 2.9 thousand cf/station in year one of the annual survey. In year 2 of the annual survey at compressor stations, there was a leak count reduction of 35% and an emission reduction of 55% compared to the initial survey year.

API recommends annual surveying with no performance based adjustment to the survey frequency.

27.3.10 Fugitive Program For Gross Emitters

On page 56637 of the preamble, EPA indicated that 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, EPA solicited comment on whether the fugitive emissions monitoring program should be limited to "gross emitters".

As EPA acknowledges, a growing body of research indicates a skewed emissions distribution for fugitive emission sources where a small number of sources are responsible for a high percentage of emissions. The fugitive emission monitoring program under OOOOa should be targeted towards identifying and correcting these high emitting sources which results in the greatest cost-effective reductions, and produces significant reductions in emissions more quickly. As indicated in Section 27.3.9, 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.

27.3.11 Recommended Rule Text Revisions Based On Comments In This Section

§60.5397a(b) You must develop a corporate-wide or area-wide fugitive emissions monitoring plan that covers the collection of fugitive emissions components at well sites and compressor stations in accordance with paragraph (c) of this section.~~, and you must develop a site specific fugitive emissions monitoring plan specific to each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station in accordance with paragraph (d) of this section. Alternatively, you may develop a site-specific plan for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station that covers the elements of both the corporate-wide and site-specific plans.~~

§60.5397a(c) Your corporate-wide or area-wide monitoring plan must include the elements specified in paragraphs (c)(1) through (8) of this section, as a minimum.

(1) Frequency for conducting surveys. Surveys must be conducted at least as frequently as required by paragraphs (f) through (i) of this section.
(2) Technique for determining fugitive emissions.
(3) Manufacturer and model number of fugitive emissions detection equipment to be used.
(4) Procedures and timeframes for identifying and repairing fugitive emissions components from which fugitive emissions are detected, including timeframes for fugitive emission components that are unsafe to repair. Your repair schedule must meet the requirements of paragraph (j) of this section at a minimum.
(5) Procedures and timeframes for verifying fugitive emission component repairs.

(6) Records that will be kept and the length of time records will be kept.
(7) Your plan must also include the elements specified in paragraphs (c)(7)(i) through (vii) of this section.

~~(i) Verification that your optical gas imaging equipment meets the specifications of paragraphs (c)(7)(i)(A) and (B) of this section. This verification is an initial verification and may either be performed by the facility, by the manufacturer, or by a third-party. For the purposes of complying with the fugitives emissions monitoring program with optical gas imaging, a fugitive emission is defined as any visible emissions observed using optical gas imaging.~~

~~(A) Your optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions.~~
~~(B) Your optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of ≤10,000 ppm at a flow rate of ≥60g/hr from a quarter inch diameter orifice.~~

~~(ii) Procedure for a daily verification check.~~

(i)~~(iii)~~ Procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained.

(ii)~~(iv)~~ Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold.

(iii)~~(v)~~ Procedures for conducting surveys, including the items specified in paragraphs (c)(7)(v)(A) through (C) of this section.

(A) How the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions.

(B) How the operator will deal with adverse monitoring conditions, such as wind.

(C) How the operator will deal with interferences (e.g., steam).

(iv)(~~vi~~) Training and experience needed prior to performing surveys.

(v)(~~vii~~) Procedures for calibration and maintenance. Procedures must comply with those recommended by the manufacturer.

§60.5397a(d) Reserved ~~Your site-specific monitoring plan must include the elements specified in paragraphs (d)(1) through (3) of this section, as a minimum.~~
~~(1) Deviations from your master plan.~~
~~(2) Sitemap.~~
~~*(3) Your plan must also include your defined walking path. The walking path must ensure that all fugitive emissions components are within sight of the path and must account for interferences.*~~

§60.5397a(g) A monitoring survey of each collection of fugitive emissions components at a well site and collection of fugitive emissions components at a transmission compressor station or central production site shall be conducted ~~at least semi~~annually after the initial survey. Consecutive ~~semi~~annual monitoring surveys shall be conducted at least 49 months apart.

API also recommends adding the following definition to §60.5430a:
Optical gas imaging instrument means an instrument that makes visible emissions that may otherwise be invisible to the naked eye. Optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions imaging a gas that is half methane, half propane at a concentration of >10,000 ppm.

27.4 Work Practices/Inspections

27.4.1 Requiring An Initial Survey Requirement Within 30 Days Of Completion Is Not Appropriate For A Number Of Reasons

> *§60.5397a(f)(1) You must conduct an initial monitoring survey within 30 days of the first well completion for each collection of fugitive emissions components at a new well site or upon the date the well site begins the production phase for other wells. For a modified collection of fugitive emissions components at a well site, the initial monitoring survey must be conducted within 30 days of the well site modification.*

There are numerous problems with this requirement both in the language chosen to describe the requirement as well as the unique technical issues that arise as a result of trying to define a well site as something other than a surface site with a well. First, within 30 days of first well completion is inappropriate, as production doesn't always begin immediately after a well completion if for example gathering infrastructure is not yet available or construction of production facilities such as storage vessels, separators, heaters and control devices are not yet complete. There may also be use of temporary equipment because of well flow problems while trying to startup production or while permanent facility construction is being completed. Instead this requirement needs to be tied to the startup of production to be consistent with other requirements in the rule such as for storage vessels.

Within the first 30 days of startup of production, production rates for wells are evaluated to determine whether any storage vessels will be affected facilities. If so, control devices are required to be constructed and operational within 60 days from startup. As well, the first 30 days may exempt a wellsite altogether if production is less than 15 BOE/day. The point is that the first 30 days of production is an evaluation period for applicability of requirements the second 30 days is allowed to complete construction of any required emissions control and closed vent system. And that is for true well sites with wells. The problem gets more complex by including central tank batteries in the definition of a wellsite rather than having its own definition as being part of a central production site that we recommended in Section 27.2.12.

Consider this realistic scenario. An operator wants to develop a new field of 20 wells that are planned to be drilled in succession, with potential plans to drill more. It is determined that it makes sense to construct a central tank battery that will become defined as a well site upon first production that will grow in size as each new well begins production and is aggregated to the central tank battery wellsite. The central tank battery is completed to enable startup of production of the first well with a capacity to eventually handle all 20 wells. After startup of the battery, semi-annual leak monitoring is required within 30 days and is completed and leaks repaired. Shortly thereafter, the second well comes online and starts production to the central battery well site, and is a wellhead only site. Now, according to §60.5397a(f)(1), the central battery must be surveyed again a month after the initial survey because of the new well. This time no leaks are found. This 30 day monitoring pattern continues until all 20 wells are completed and will continue if more wells are immediately added or first wells are refractured for any reason. The wellhead only sites are also monitored each time since they are part of the central battery well site.

The point of the scenario is that the wellsite definition is not workable in terms of the how the initial monitoring requirements have been designed in this proposal. Instead of monitoring a central tank battery initially, then semi-annually, to hopefully annually as currently conceived in the proposal, the central production site and all wells tied into it will have to undergo monitoring at an unpredictable frequency based on changes that don't occur at the battery but rather wells tied into it. The battery will always require initial well monitoring as will all the wells tied to it within 30 days each time a new well is added or refracture occurs at an existing well. This is overly burdensome and costly. Again, API recommends dissociating central batteries from the well site definition to avoid this situation.

Instead of 30 days, the time period for the initial survey should be within 180 days after startup of production to allow sufficient time for completion of construction and the startup period, and scheduling the new site into the area leak detection plan. After the initial 60 days to complete construction of the control device, an additional 120 days should be allowed to work monitoring of the well into the next scheduled monitoring period that would include all the wells in the area. Calling out a contract crew to monitor one remote well site, when in a matter of a few weeks or couple months they may already be scheduled to monitor an entire area is not a cost efficient use of manpower. Such inefficient use of resources could put undue pressure on availability of crews for all operators.

Suggested regulatory revisions are provided at the end of this section (see Section 27.4.14).

27.4.2 Quarterly Monitoring for Super Emitters

Recognizing that additional data may be available, such as emissions from super emitters that may have higher emission factors than those considered in this analysis, EPA indicated that they are taking comment on requiring monitoring survey on a quarterly basis.

As indicated in Section 27.3.9, API finds that recurring LDAR has diminishing return.

Quarterly monitoring may not be possible in all areas. For example in some areas, particularly in western mountainous areas, winter weather makes it difficult to visit well sites that can be remote and widely scattered. It also may not be possible to utilize OGI methods in winter conditions, since visual detection of leaks requires a temperature difference between the leak and ambient air. Test data presented in Table 4-13 of EPA's draft Technical Support Document (TSD) *Optical Gas Imaging Protocol (40 CFR Part 60, Appendix K)*[33] shows that 5,000 ppm leaks were detected with delta temperatures between the gas leak and background of around 1.4 to 1.9°C (2.5 to 3.4°F). However, the delta temperature is highly dependent on other factors, such as the wind conditions, hydrocarbon concentration, and mass emission rate.

In addition, even EPA's cost analysis found that the cost of monitoring/repair based on quarterly monitoring at well sites using OGI is not cost-effective for reducing VOC and methane emissions. Per page 56636 of FR version, EPA indicates: "In a previous NSPS rulemaking [72

[33] Reference: *Draft Technical Support Document for Optical Gas Imaging Protocol (40 CFR 60, Appendix K)*, Revision No. 5, August 11, 2015, EPA Contract No. EP-D-11-006 by Eastern Research Group, Inc., available at http://www.regulations.gov/contentStreamer?documentId=EPA-HQ-OAR-2010-0505-4949&disposition=attachment&contentType=pdf

FR 64864 (November 16, 2007)], **we had concluded that a VOC control option was not cost-effective at a cost of $5,700 per ton**. In light of the above, we find that the cost of monitoring/repair based on quarterly monitoring at well sites using OGI is not cost-effective for reducing VOC and methane emissions under either approach."

27.4.3 API Advocates A Fixed Initial Annual Frequency, Regardless Of The Percent Of Leaking Components

EPA solicit comment on the proposed metrics of one percent and three percent and whether these thresholds should be specific numbers of components rather than percentages of components for triggering change in survey frequency discussed in this action.

API does not support the proposed metrics of one percent and three percent of components specified in §60.5397a(i) and (h), respectively, as these metrics require maintaining a count of all fugitive components. API advocates a fixed initial annual frequency, regardless of the percent of leaking components. **Therefore, API recommends removing both paragraphs (h) and (i) in §60.5397a.**

To count and tag components at a compressor station, costs approximately $10,000 and requires continual maintenance and management. In a study performed by an API member company which compared three basic leak detection methods: AVO, OGI, and M21, component counts were made by a manual observer while on site. Because M21 was already being conducted, the additional cost of component counts was $15 to $58 per well site. However, if done in conjunction with an OGI method, the cost would be higher because individual components need not be individually located for the purposes of OGI monitoring. API companies estimate a cost of $120 per well site to count components initially, with a recurring cost of $60 per well site to validate and update the counts annually.

27.4.4 Proposed Approach To Allow Reduction In Monitoring Frequency Forces The Need To Develop Equipment Count For Each Well Site In Order To Properly Document The Percent Leaking Components. This Is Inconsistent With Subpart W Monitoring Program For Transmission And Storage

API does not support the proposed metrics based on a direct count of all fugitive components, which can be time consuming and costly. If EPA elects to use a component count, API recommends that a simplified approach, such as the 40 CFR 98 Subpart W upstream component count approach would be used [specified in §98.233(r)]; that method only requires a count of major pieces of equipment which are combined with EPA assumptions on component counts per equipment.

See Section 27.3.9 regarding API's recommendation for annual monitoring.

27.4.5 Recognize That Subpart W Already Requires Annual Fugitives Reporting For Certain Compressor Stations That Exceed The 25,000 Metric Ton CO_2e Threshold, And Request Comments On The Overlap Of These Reporting Requirements

§60.5397a(a) You must monitor all fugitive emission components, as defined in 60.5430a, in accordance with paragraphs (b) through (i) of this section. You must repair all sources of fugitive emissions in accordance with paragraph (j) of this section. You must keep records in accordance with paragraph (k) and report in accordance with paragraph (l) of this section. For purposes of this section, fugitive emissions are defined as: Any visible emission from a fugitive emissions component observed using optical gas imaging.
(g) A monitoring survey of each collection of fugitive emissions components at a well site and collection of fugitive emissions components at a compressor station shall be conducted at least semiannually after the initial survey. Consecutive semiannual monitoring surveys shall be conducted at least 4 months apart.

For transmission compressor stations or storage stations that exceed the reporting threshold of 25,000 tonnes CO2e, Subpart W requires annual leak detection surveys at natural gas transmission and storage stations using Optical Gas Imaging, M21, or Infrared laser beam illuminated instrument [as specified in 40 CFR 98.233(q)(1) and 98.234(a)]. Subpart OOOOa is imposing a different frequency (semi-annual), more limited detection methods (OGI only), different reporting requirements, and a separate monitoring program than Subpart W for new or modified compressors stations. This creates duplicative and conflicting requirements. Subpart OOOOa should not apply to compressor stations currently regulated under Subpart W.

27.4.6 API Opposes Performance-Based Frequency

EPA solicited comment on whether a performance-based frequency or a fixed frequency is more appropriate. API does not support a performance based frequency that is currently specified in §60.5397a(h) and (i). Tracking sites based on performance criteria is unnecessary and complex. A fixed annual frequency is sufficient for detecting and repairing leaks, as indicated in Section 27.3.9, and simplifies compliance. API members find that recurring LDAR has a diminishing return. The first survey identifies and corrects most of the leaks, but significantly fewer leaks are identified in subsequent surveys.

27.4.7 API Suggests 30 Days An Appropriate Amount Of Time For Repair Of Sources Of Fugitive Emissions At Well Sites

EPA solicited comment on whether 15 days is an appropriate amount of time for repair of sources of fugitive emissions at well sites. Many leaks detected can be repaired on site with simple tightening of screwed connections, or replacement of small components carried by the maintenance team if authorized maintenance personnel are available around the time of the survey. Fifteen days is adequate in these circumstances. However some leaks require more time to repair due to safety issues, availability of replacement parts, availability of maintenance personnel, weather conditions, or other issues related to the sites being remote, dispersed, and unmanned facilities. Also, the availability of training LDAR staff to re-monitor and validate that the component is indeed repaired is another logistical reason that more time is needed. Thus, API requests that 30 days be provided to complete the repairs.

Proposed text revisions are provided in Section 27.4.14.

27.4.8 The Current Proposal Does Not Allow For Multiple Attempts To Repair Identified Leaks.

In the proposed regulation, EPA requires discovered leaks to be repaired within 15 days. Multiple attempts to repair may be required to repair such that 15 days is not be adequate to make a successful repair. Provisions are needed to allow for occurrences where complex leaks cannot be fixed within 15 days. These may be situations where additional engineering and analysis is required to develop the safe and correct solution to repair the leak. There needs to be sufficient regulatory flexibility to address instances where several repair attempts are needed until the leak is repaired.

EPA should provide appropriate provisions to accommodate situations where multiple attempts are required to repair a leak. Proposed text revisions are provided in Section 27.4.14.

27.4.9 Forcing All Repairs Within 6 Months Is Unreasonable Due To True Cost Impacts.

A minority of detected leaks require more time to be repaired because they require a full shutdown of the well in order to do the repair. For example, recent data from Colorado's Reg 7 indicate that about 5% of identified leaks required a delay of repair.[34] Repairs on the well head itself require full shutdown of the well. Some repairs require a workover of the well. Also, many companies do not allow hot work to be performed on the well site due the risk of explosion or fire. The well must be shut in and the equipment purged in order to do any hot work such as welding for repairs. Many different issues must be assessed before a well is shut in and equipment purged for repairs. Shutting down the well could result in losing the well completely or damage to the formation that can reduce production. The emissions from shutting in the well and purging the equipment could result in more emissions than are being released from the leak. Also, EPA did not consider the cost of lost production during repairs in the cost analysis for fugitive leaks which can be significant.

Some repairs at compressor stations require the compressor station to be shut in which could require shutting in all the wells that feed into the compressor station as well. Most compressor stations in the gather system do not have a way to by-pass the compressor or parts of the system so work can be done. Bringing down the compressor station could result in shutting in parts of a field and losing the production from that portion of the field which is a huge cost. Lost production from compressor shutdowns was not included in EPA's cost estimate.

The unreasonableness of the requirement to repair a leak within 6 months is even more apparent when applied to integrated production arrangements such as those on the North Slope of Alaska. Fields on the North Slope are arranged with multi-well pads feeding into a small number of centralized production stations where primary separation and some pre-treating and compression of gas occurs. Gas from these central production stations is routed to a gas processing facility, oil to the Trans-Alaska Pipeline, and produced water to reinjection. Dependent on where a leak occurs in this integrated production arrangement repairing a leak within 6 months may necessitate shutting down an entire section of a field feeding a particular central production station or perhaps a series of central production stations. Given the geographic and seasonal realities of the Alaskan North Slope, oil and gas operators schedule large separation facilities shutdowns during the summer months. With the litany of plausible scenarios that could result in a separation facility being required to shut down in order to fix a leak in late fall, winter, and early spring, such shutdowns will result in greater safety and integrity concerns. In addition, the flaring of between 250,000 MMscf and 500,000 MMscf of gas during shutdowns may be an unintended and unavoidable consequence of the proposed rule. Simply stated, the emissions release associated with shutting down a production facility; shutting in and freeze protecting wells; and depressuring and purging the necessary equipment will result in far greater emissions than are being released from the leak that could be repaired during the next scheduled process shutdown. In addition to the increased safety concerns and counter-productive flaring, implementing the repair requirements as currently drafted will also result in severe economic repercussions. Every day of a non-scheduled or non-summer shutdown will result in millions of dollars in lost revenue for the State of Alaska and the operators. Dependent on the length and extent of the shutdown required and difficulty restarting the wells and facilities, taking such an action may impact the domestic US supply of crude oil, particularly in the West Coast markets where most Alaska crude is shipped. It is clear that EPA did not contemplate such potential wide ranging and large impacts when considering the requirement for repair of a leak within 6 months. Although the

[34] Colorado Air Quality Control Commission, Public meeting on October 15, 2015.

North Slope is an extreme example due to the unique climate realities, similar impacts would occur on a smaller scale for other integrated production arrangements.

EPA should allow for delay of repair of fugitive components until the next shutdown. EPA has allowed for delay of repairs beyond 6 months for reasons other than technical feasibility and safety, such as availability of supplies, availability of custom parts and where shutdown emissions are larger than what would be reduced. Subpart §OOOOa should be less stringent than what is required under VVa. VVa under 60.482-9a allows for the following delay of repairs and NSPS OOOOa should allow for equivalent delay of repair:

> §60.482-9a*(a) Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit.*
>
> *(b) Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.*
>
> *(c) Delay of repair for valves and connectors will be allowed if:*
>
> *(1) The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and*
>
> *(2) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with §60.482-10a.*
>
> *(d) Delay of repair for pumps will be allowed if:*
>
> *(1) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and*
>
> *(2) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.*
>
> *(e) Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.*
>
> *(f) When delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring instrument readings are below the leak definition."*

API was unable to gather and provide the typical times between shutdowns of well sites and compressor stations due to the short comment period on this rule.

Proposed text revisions are provided in Section 27.4.14.

27.4.10 Thresholds for M21 Leak Definition and Repair

EPA requested comment on whether the fugitive emissions repair threshold for M21 monitoring surveys should be set at 10,000 ppm or whether a different threshold is more appropriate (including information to support such threshold). In addition, EPA solicited comment on whether 500 ppm above background is the appropriate repair resurvey threshold when M21 instruments are used or if not, what the appropriate repair resurvey threshold is for M21.

Tables 9-14, 9-15, and 9-16 of the CTG draft show the summaries of the cost of control for VOC at each of the repair thresholds (i.e., 10,000, 2,500, and 500 ppm) for the three monitoring frequency options (i.e., annual, semiannual, and quarterly).

For leak repairs that are not repaired during the initial survey, Subpart OOOOa allows either an OGI or M21 test with a leak threshold of 500 ppm to confirm that it is repaired [§60.5397a(j)(2)(i) and (ii)]. If M21 is used to repair the leak, then the leak definition should instead be 10,000 ppm instead of 500 ppm. A leak definition of 10,000 ppm is consistent with the leak definition used in NSPS Subpart KKK for valves at natural gas processing plants, which references NSPS Subpart VV. Also, OGI monitors detect leaks at approximately 10,000 ppm. Even in OOOOa for a gas plant, all the components do not have to meet 500 ppm. In addition, API demonstrated in comments provided to Docket ID Number EPA–HQ–OAR–2010–0505 (Proposed Rulemaking – Oil and Natural Gas Sector Regulations Standards of Performance for New Stationary Sources: Oil and Natural Gas Production and Natural Gas Transmission and Distribution, November 30, 2011) that there is only a small incremental difference in emission reductions between a leak definition of 500 ppm and 10,000 ppm.

Based on data in a leak detection study that compared M21 to FLIR, approximately 85% of FLIR-found-leaks were over 0.1 scfh, as quantified by HiFlow. Using the correlation equation from the 1995 Protocol for Equipment Leak Emission Estimates and the average density of the field gas in the corresponding asset areas, 10,000 ppm corresponds to a leak rate range of 0.07 to 0.15 scfh depending on the component type leaking. Based on this, the study found that approximately 70% of FLIR-found-leaks were over 10,000 ppm.

Therefore, consistent with the valve leak detection provided in NSPS Subparts KKK and VV, and given that OGIs typically detect leaks over 10,000 ppm, the repair leak definition should be changed in proposed §60.5397a(j)(2)(ii) from 500 ppm to 10,000 ppm.

Proposed text revisions are provided in Section 27.4.14.

27.4.11 API Supports Flexibility In The Methods Allowed For Resurveying Repaired Components.

EPA solicited comments on whether either optical gas imaging or M21 should be allowed for the resurvey of the repaired components when fugitive emissions are detected with OGI. API supports flexibility in the methods allowed for resurveying repaired components. EPA should allow for the use of M21, OGI, or infrared laser beam illuminated instruments. In particular, M21 is preferred, as Section 8.3.3 of M21 allows the use of soap bubbles for leak detection, which currently does not appear to be allowed per §60.5397a (j)(2)(i):

> *§60.5397a (j)(2)(i) For repairs that cannot be made during the monitoring survey when the fugitive emissions are initially found, the operator may resurvey the repaired fugitive emissions components using either M21 or optical gas imaging within 15 days of finding such fugitive emissions.*
>
> *(ii) Operators that use M21 to resurvey the repaired fugitive emissions components, are subject to the resurvey provisions specified in paragraphs (j)(2)(ii)(A) and (B).*
> *(A) A fugitive emissions component is repaired when the M21 instrument indicates a concentration of less than 500 ppm above background.*
> *(B) Operators must use the M21 monitoring requirements specified in paragraph §60.5401a(g).*
> *(iii) Operators that use optical gas imaging to resurvey the repaired fugitive emissions components, are subject to the resurvey provisions specified in paragraphs (j)(2)(iii)(A) and (B).*

(A) A fugitive emissions component is repaired when the optical gas imaging instrument shows no indication of visible emissions.
(B) Operators must use the optical gas imaging monitoring requirements specified in paragraph (a).

27.4.12 Monitoring Each Fugitive Component for Emissions

§60.5397a(e) – EPA is requiring that "*Each monitoring survey shall observe <u>each fugitive emissions component</u> for fugitive emissions*." Having to look at each component with an OGI system is extremely time consuming. Furthermore, it is not necessary to look at each component for leaks with the OGI equipment. From a scan around the facility you should be able to easily see if there are any leaks, and then if there are, move in to identify the exact location of the leak. OGI does not work like M21 where you have to sniff each component to determine if it is leaking.

Also, it is not always feasible to look at each component. Several locations in the North have equipment inside buildings with components next to the wall making getting to each component with OGI equipment impossible. . Here is an example of what the sites look like:

Figure 27-1 Picture of Equipment Building

API recommends making this requirement more in line with how OGI equipment works and the fact that each component does not need to be scanned to require that each piece of equipment with fugitive monitoring components be observed. For instance, observe the separator or well head for leaking components

Proposed text revisions are provided in Section 27.4.14.

27.4.13 Application of Fugitive Emission Requirements at Modified Sites

EPA requested comment on 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**.**

For well sites, it is more complicated and difficult to manage to do fragmented LDAR based on difference applicability and different frequencies. Similarly it is complicated and difficult to manage a partial LDAR applied to different equipment or components at a given site. If a company is going to conduct LDAR for a specific piece of equipment at a site, it is just as efficient to scan the entire site. API supports annual LDAR for all the equipment located at an applicable well site.

27.4.14 Recommended Text Revisions Related To Work Practices/Inspections

§60.5397a(e) Each monitoring survey shall observe each piece of equipment with fugitive emissions components for fugitive emissions.
(f)(1) You must conduct an initial monitoring survey within ~~30~~180 days of the first date of production ~~well completion~~ for each collection of fugitive emissions components at a new well site ~~or upon the date the well site begins the production phase for other wells~~. For a modified collection of fugitive emissions components at a well site, the initial monitoring survey must be conducted within ~~30~~180 days of the well site modification.

§60.5397a(f)(2) You must conduct an initial monitoring survey within ~~30~~180 days of the startup of a new compressor station or central production site for each new collection of fugitive emissions components at the new compressor station or central production site. For modified compressor stations or central production sites, the initial monitoring survey of the collection of fugitive emissions components at a modified compressor station or central production site must be conducted within ~~30~~ 90 days of the modification. For affected facility compressor station or central production sites constructed between Sept. 18, 2015 and 60 days after [final date of rule], initial surveys must be completed by [insert one year and 60 days after final rule promulgation]

§60.5397a(j)(1) Each identified source of fugitive emissions shall be repaired or replaced as soon as practicable, but no later than ~~15~~30 calendar days after detection of the fugitive emissions. If the repair or replacement is technically infeasible or unsafe ~~to repair during operation of the unit~~, the repair or replacement must be completed during the next scheduled shutdown ~~or within 6 months, whichever is earlier~~.

§60.5397a(j)(2)(ii)(A) A fugitive emissions component is repaired when the M21 instrument indicates a concentration of less than ~~500~~10,000 ppm above background.

27.5 Testing and Monitoring

27.5.1 Other Fugitive Emission Detection Technologies

EPA requested comment on whether there are other fugitive emission detection technologies for fugitive emissions monitoring, since this is a field of emerging technology and major advances are expected in the near future.

In the preamble, EPA states:

"We are aware of several types of technologies that may be appropriate for fugitive emissions monitoring such as Geospatial Measurement of Air Pollutants using OTM-33 approaches (e.g., Picarro Surveyor), passive sorbent tubes using EPA Methods 325A and B, active sensors, gas cloud imaging (e.g., Rebellion photonics), and Airborne Differential Absorption LiDAR (DIAL). Therefore, we are specifically requesting comments on details related to these and other technologies such as the detection capability; an equivalent fugitive emission repair threshold to what is required in the proposed rule for OGI; the frequency at which the fugitive emissions monitoring surveys should be performed and how this frequency ensures appropriate levels of fugitive emissions detection; whether the technology can be used as a stand-alone technique or

whether it must be used in conjunction with a less frequent (and how frequent) OGI monitoring survey; the type of restrictions necessary for optimal use; and the information that is important for inclusion in a monitoring plan for these technologies."

Ongoing Research and Development Activities

The scale up of LDAR activities under the draft rule provides a strong incentive to bring down costs while enhancing leak detection effectiveness, and is already stimulating a substantial increase in R&D investment, as EPA notes in its proposal. We call to the Agency's attention two ongoing initiatives that aim to develop improved LDAR technologies for use by companies as they seek to comply with federal and state methane emissions reduction requirements: a public-private initiative and a partnership between a number of corporate actors and an environmental non-governmental organization. These initiatives may well demonstrate within the next several years, the commercial availability of substitute technologies, equipment and approaches that are more efficient and cost-effective than the continued use of Method 21 or OGI.

Department of Energy (DOE)/ Advanced Research Projects Agency – Energy (ARPA-E). As of December 16, 2014, ARPA-E had selected eleven private sector projects involving methane observation networks with innovative technologies to obtain methane emissions reductions that would receive awards totalling some $35,000,000, (MONITOR Program). The objective is to catalyze and support the development of transformational, high impact energy technologies that can effectively promote methane emissions reduction. DOE's aim is to lower the cost of compliance through the development of low cost detection systems coupled with advanced modelling capabilities to pinpoint and quantify - major leaks and engage in mitigation prioritization with a focus on larger emitters. The proposed rule's approach, consistent with current technology, relies on detection alone as the criteria to define the need for repair without any prioritization based on the size of the leak. Generally the thrust of the work being supported by ARPA-E does not look at leaks from individual components, but will lead to examination of larger areas to identify significant leaks which can then be specifically identified and repaired.
ARPA-E is planning within 6-7 months to set up a testing facility intended to serve as a site for field tests to ensure that technologies are tested in a standardized, realistic environment outside of the laboratory. This would be followed by a second round of testing to assess previously undemonstrated capabilities and further technical gains. ARPA-E believes some of these technologies could become commercially available in from 2-3 years. The goal within 18 months to 2 years is to develop a methodology to demonstrate the superiority of one or more of these technologies to OGI that do not require the manpower, the fleets of trucks and other equipment and surveys that are time-consuming to undertake and dwarf the cost to the regulated community even of an expensive FLIR camera ($90,000). Each of ARPA-E's partners will need to demonstrate it can bring the costs down to $3,000 per site per year (many of which have multiple wells). The hope and expectation is that costs will be significantly lower, going down as to as little as $1,000 per site.

EDF Methane "Detectors Challenge" (MDC). In June 2014, the Environmental Defense Fund (EDF) along with five private sector partners issued a request for a proposal intended to target innovators from universities, start-up companies, instrumentation firms, and diversified technology companies among others to develop continuous methane leak detection monitoring for the oil and gas industry. They also sought expressions of interest in becoming part of the lab and field tests that would lead to pilot purchases and testing at oil and gas facilities. The initiative is intended to catalyze and expedite development and commercialization of low-cost, methane detection technologies that will help minimize emissions in the oil and gas industry. MDC is based upon the belief that shifting the methane emission detection paradigm from periodic to continuous will allow leaks to be found and fixed, more readily decreasing methane emissions significantly. The ideal system would serve as a "smart" alarm sending an alert to an operator when an increase in ambient methane is detected that reflects emissions beyond what one would normally expect to see. The "MDC program refers to cost as a critically important factor and EDF and its partners

sought out technologies that could reasonably be expected to be sold for roughly $1,000 or less per well pad (or compressor site) when produced at scale over the following 2-5 years.
The MDC commenced with a set of laboratory tests of five different sensor technologies in 2014, called "Phase 1." Four of these five technologies were selected for further development and assessment in a follow-up effort referred to as "Phase 2" which tested each technology developer's entire system in controlled laboratory and outdoor settings in order to ensure that the systems performed as required prior to moving into industry pilots, which is the immediate next step.

We urge EPA to stay abreast of technological developments and closely track the results of research and testing through an open dialogue with experts in the private sector and government.

Recommendations

An optical gas imaging (OGI) instrument is defined in 40 CFR 60.18(g)(4) as "… an instrument that makes visible emissions that may otherwise be invisible to the naked eye." EPA's Technical Support Document (TSD) for Optical Gas Imaging Protocol (40 CFR Part 60, Appendix K)[35] provides a summary of the current state of the technology for two commercially available OGI cameras, the FLIR GF320 and Opgal EyeCGas, to detect equipment fugitive leaks by infrared thermographic imaging.

EPA should write the rule to allow any new technology to be used that is equivalent to OGI or Method 21 in detecting fugitive leaks. Such new technologies should not be limited to meeting EPA's current definition of OGI (i.e. "… an instrument that makes visible emissions that may otherwise be invisible to the naked eye."). In addition, since OOOOa is not a quantification rule, such new technologies need only demonstrate that they can detect leaks; they do not need to quantify leaks.

27.5.2 The Regulation Should Allow Flexibility In The Methods Used To Detect Fugitive Emissions

The Agency has asked for comment on "criteria we can use to determine whether and under what conditions well sites operating under corporate fugitive monitoring programs can be deemed to be meeting the equivalent of the NSPS standards for well site fugitive emissions such that we can define those regimes as constituting alternative methods of compliance or otherwise provide appropriate regulatory streamlining."

A study performed by an API member company compared three basic leak detection methods: AVO, OGI, and M21. In general, the M21 approach was the most labor and time intensive, and, therefore, the most costly. FLIR methods could be implemented for less than 20% of the cost of M21 approaches. The results showed that AVO, while the least costly method, was not generally effective when compared to M21. On average, AVO found only 9% of the well pad leaks found by M21, and only 12% of the well pad site emissions calculated from M21 leaks. At the compressor station, because of the high ambient noise and close proximity of equipment, AVO method was not effective at all, and found 0% of the leaks found by M21 methods. The FLIR technique, on the other hand, was more effective.

- At well pads, FLIR finds 41% of leaks found by any method, but FLIR finds 89% of the total well pad emissions identified by any method (i.e. FLIR finds more of the larger leaks). It is also important to note that FLIR finds additional leaks not found by M21.

[35] Reference: *Draft Technical Support Document for Optical Gas Imaging Protocol (40 CFR 60, Appendix K)*, Revision No. 5, August 11, 2015, EPA Contract No. EP-D-11-006 by Eastern Research Group, Inc., available at http://www.regulations.gov/contentStreamer?documentId=EPA-HQ-OAR-2010-0505-4949&disposition=attachment&contentType=pdf

Conversely, M21 finds 89% of the leaks, but only 31% of the total emissions (i.e. M21 finds more of the smaller leaks).

- At compressor stations, FLIR finds 46% of all leaks found by any method, but FLIR finds 96% of the total compressor station emissions identified by any method. It is also important to note that FLIR finds additional leaks not found by M21. Conversely, M21 finds 75% of the leaks, but only 15% of the total emissions.

Although AVO was not effective in this particular study, there are locations with high H_2S concentrations where AVO is more effective than M21. Sites with high levels H_2S should be allowed to use AVO or H_2S monitoring systems to identify leaks at well pads.

27.5.3 For Laser Technology, Etc., How Might Performance Requirements Be Characterized?

Subpart W allows the use of an infrared laser beam illuminated instrument for equipment leak detection [§98.234(a)(3)]. Any emissions detected by the infrared laser beam illuminated instrument is a leak unless screened with M21 monitoring, in which case 10,000 ppm or greater is designated a leak. However, since OOOOa does not require quantification, API does not advocate establishing a specific ppm threshold for determining a leak.

27.5.4 A Streamlined Approval Process Is Needed For Adoption Of Alternative Technologies As They Are Developed, Shown To Be Effective And Become Commercially Available

EPA should build into its final rule an "on-ramp" that provides an alternative path for rapid substitution of new detection equipment and monitoring strategies once they are validated and shown to be effective. This should include a fast-track review process, with firm deadlines for decision-making so that alternatives to the current LDAR requirements can be approved without time-consuming amendments to the NSPS.

As a general matter, the rule should seek to establish a more streamlined "fast-track" process for approving new detection technology that can be substituted in lieu of OGI equipment whether its use does not require modification of the LDAR protocol, or is an entirely new approach (continuous monitoring).

Where a new technology has been adequately field tested and validated through the ARPA-E MONITOR or another program and meets performance specifications outlined by EPA, the rule should authorize its deployment following a review by the Agency. The review should be completed within 180-days following submission of a complete data package by the technology developer or an oil or gas company the Agency, and the technology should be deemed approved for use unless it is disapproved by the Agency within that period. This deadline should be included in the rule itself to assure expedited action.

Detection level "equivalency" should not be required as EPA has required for using OGI versus Method 21. Because new detection equipment may have very different capabilities from existing technologies, it is critical to avoid a narrow "equivalence test for approving alternative methods. Moreover, the stringency of the process and "equivalency" testing has made it impossible to get other technologies approved. The excessive requirements EPA has put under the Alternative Leak Detection Program in 60.18(g) has made it so that no company is utilizing OGI.

Colorado Regulation 7[36] provides a process for approving new alternative Approved Instrument Monitoring Methods (AIMM) that could serve as a basis for OOOOa:

At a minimum, the technology must be able to pinpoint the general location of leaking or venting emissions. For non-quantifying devices, the device must be capable of detecting all hydrocarbons, and testing and certification must be repeatable. Colorado Regulation 7 also requires an indication of limitations, other applications, how the device works, how it will be used, the process for recordkeeping, and training required. Colorado Regulation 7 may also require comparative monitoring with either an IR Camera or Method 21.

API recommends that EPA allow for the use of alternative monitoring that detects leaks based on the following criteria:

- Occurs at least annually
- Pinpoints the general location of the leak
- Detects the hydrocarbons found at the sites
- Testing and certification must be repeatable
- Indication of limitations, other applications, how the device works, how it will be used, the process for recordkeeping, and training required.

27.5.5 Allowance Of EPA M21 As An Alternative to OGI

EPA solicited comment on whether to allow EPA Method 21 as an alternative to OGI for monitoring, including the appropriate EPA Method 21 level repair threshold

Proposed Subpart OOOOa implies that the initial leak surveys must be taken using an OGI [§60.5397a(c)(7)]. We recommend revising the rule to specifically state that OGI, Method 21, or an equivalent method may be used for both the initial survey [§60.5397a(c)(7)] and repair leak surveys [§60.5397a(j)(2)].

In addition, EPA should allow the use of soap bubbles for leak detection, since EPA approves Method 21 for repair confirmation and emissions quantification is not required under OOOOa. According to Section 8.3.3 of Method 21, leaks may be screened using the presence of soap bubbles. If bubbles are not observed, then the source is assumed to have no detectable emissions under Method 21. EPA allows the use of 8.3.3 for other industries including chemicals and refining. It should be allowed here too. The leaks may not be repaired by the same person doing the leak survey. Allowing the soap bubble test would allow the person doing the repair to check the repair without requiring the leak survey person to have to go out to the site for a second time. This would reduce the time and expense required for doing repairs.

27.5.6 Proposed Text Revisions Related To Testing And Monitoring Requirements

> §60.5397a(a) You must monitor all fugitive emission components, as defined in 60.5430a, in accordance with paragraphs (b) through (i) of this section. You must repair all sources of fugitive emissions in accordance with paragraph (j) of this section. You must keep records in accordance with paragraph (k) and report in accordance with paragraph (l) of this section. For purposes of this section, fugitive emissions are defined as: Any visible emission from a fugitive emissions component observed using optical gas

[36] https://www.colorado.gov/pacific/sites/default/files/AP-BusIndGuidance-AIMMprocessmemo.pdf

imaging, methods listed under 60.5397a(h), or approved alternative detection device under paragraph (m) of this section.

§60.5397a(j)(2)(i) For repairs that cannot be made during the monitoring survey when the fugitive emissions are initially found, the operator may resurvey the repaired fugitive emissions components using ~~either Method 21 or optical gas imaging~~ one of the methods specified in §60.5397a(h) within 15 days of ~~finding such~~ repairing the fugitive emission~~s~~ source.

Add new proposed §60.5397a(h) below and re-letter paragraphs (h) through (l) to (i) to (m) to accommodate this addition:

§60.5397a(h). The initial and subsequent monitoring surveys specified in paragraphs (f) and (g) of this section must be conducted using one of the following methods:
(1) Optical gas imaging equipment.
(2) Method 21 (including soap bubbles as specified in Method 21, Section 8.3.3).
(3) A method that the company keeps records to demonstrate that is equivalent in detecting leaks to either of the methods specified in paragraphs (h)(1) or (h)(2) of this section.
(4) Screening methods, including but not limited to Tunable Diode Laser Absorption Spectroscopy (TDLAS), Interference Polarization Spectrometer (IR-CIPS), or Differential Absorption Light Detection and Ranging (DIAL LiDAR) technology, that screen for no leaks. If these methods do not detect a leak, then that survey is considered to have identified no leaks. However, if a leak is identified by one of these screening methods, then a monitoring method specified in paragraph (h)(1), (h)(2), or (h)(3) of this section must be used to confirm the presence of the leak.

Add:
(m) Alternative detection devices that can meet the following criteria can be submitted for approval for use by the Administrator or delegated authority within 180 days of a complete submittal:

(1) Occurs at least annually
(2) Pinpoints the general location of the leak
(3) Is capable of detecting the hydrocarbons found at the site
(4) Testing and certification are repeatable
(5) Information on the limitations, other applications, how the devices works, how it will be used, and the process for recordkeeping and training are provided.

27.6 Reporting and Recordkeeping

27.6.1 The Rule Should Not Require A Separate Report For Each Well Site

API interprets "each collection of fugitive emissions components" in §60.5397a(l) (provided below for reference) to refer to a single LDAR survey at a well site or compressor station. The requirement to provide a separate report for each well site, even where the report can combine multiple emission surveys at a well site, is onerous. API requests the option to combine reports for multiple wells sites or compressor stations and submit the combined reports in one annual report.

> *§60.5397a(l) Annual reports shall be submitted for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station that include the information specified in § 60.5420a(b)(7). Multiple collection of fugitive*

emissions components at a well site or collection of fugitive emissions at a compressor station may be included in a single annual report.

27.6.2 The Requirement For Capturing Photo / Image Of Leaker Is Onerous And Of Limited/No Value

> *§60.5397a(k)(6)(ii) One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the well site or compressor station imbedded within or stored with the digital file. 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.*

EPA is building on their alternative compliance requirement to submit photos of REC equipment for green completions by proposing to require a photograph of each affected well site or compressor station for each monitoring survey performed per *§60.5397a(k)(6)(ii)*, which is provided above for reference. However, under the well completions portion of the rule, a photograph is offered as an alternative to the records required. However, for the OOOOa LDAR requirements it does not appear to be offered as an alternative but just additional recordkeeping.

The photo must include the date the photograph was taken and the latitude and longitude of the well site imbedded within or stored with the digital file and must identify the affected facility. It is not clear what purpose photos of the affected well site or compressor station would serve. The preamble states (80 FR 56615) that a photo of each component that is surveyed is not required, yet a single photo of the well site or compressor, which would meet the rule requirements, is not going to show all of the surveyed components, does not show that a survey was done, and will not provide any indication that a leak was repaired.

The OOOOa requirements indicate that a photograph must be taken of 'each source of fugitive emissions" - §60.5397a(k)(6)(ii)– which is an actual leak. The proposed regulatory language and preamble appear inconsistent. A photo of a survey being conducted does not provide any additional compliance assurance that the survey requirements were met. Relying on the operator's certification, procedure, and documentation of repairs provides the greatest amount of compliance assurance for an OGI survey.

In addition, photographs create a security risk such as terrorist activities, retaliation, and anti-competitive activities. Oil and natural gas production and gathering operations are generally un-manned and may not have security measures such as cameras, fences, or gates. The proposed photos of fugitive monitoring activities will inherently capture details that would otherwise not be available. If EPA chooses to require photographs in electronic reporting, these detailed photos will be centralized in the public domain. Individuals with no interest in fugitive monitoring activities will have interest in viewing the photographs. EPA and states will inevitably receive Freedom of Information Act (FOIA) requests for reasons unrelated to fugitive monitoring.

Finally, keeping records of all the photographs will require of the great amount of storage which EPA did not account for in the cost estimate. API members estimate the data storage requirement for these photos is approximately 100 MB per well site survey.

Photographs do not provide any additional environmental benefit and should not be required under Subpart OOOOa for fugitive emissions monitoring. **API requests that EPA remove the requirement to take a photograph.**

27.6.3 API Strongly Opposes Sending Digital Photographs And Logs To Permitting Agencies

EPA is seeking comment on page 56615 of the preamble "on whether these [digital photographs and logs] records also should be sent directly to the permitting agency electronically to facilitate review remotely; and how to minimize recordkeeping and reporting burdens." API strongly opposes sending digital photographs and logs to the permitting agencies. EPA's cost estimate did not account for the burden of data storage requirements and management of data that would be place on the states. There is no apparent benefit to requiring the state to manage and maintain copies of this information. And, as indicated previously, there are real security risks when putting photographs in the public domain that includes geo data for exact location of sites that are unmanned with limited security.

27.6.4 Visual Inspections Are Part Of Regular Operational Activities And Should Not Be Required In A Formal Protocol

EPA is seeking comment on page 56612 of the preamble 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. These types of observations are part of regular operational activities and should not be required in a formal protocol.

27.6.5 EPA Needs To Reduce The Recordkeeping And Reporting Burden For Leaks

The recordkeeping and reporting requirements of Colorado Regulation 7 are significant, although the requirements are far less than EPA has proposed in this rule. Furthermore, they add burden to the operator without any environmental benefit. The recordkeeping and reporting requirements NSPS OOOO should be greatly reduced. Colorado Regulation 7 only requires that the following records be maintained:

> *"XVII.F.8.Recordkeeping: The owner or operator of each facility subject to the leak detection and repair requirements in Section XVII.F. must maintain the following records for a period of two (2) years and make them available to the Division upon request.*
> *XVII.F.8.a. Documentation of the initial approved instrument monitoring method inspection for new well production facilities;*
> *XVII.F.8.b. The date and site information for each inspection;*
> *XVII.F.8.c. A list of the leaking components and the monitoring method(s) used to determine the presence of the leak;*
> *XVII.F.8.d. The date of first attempt to repair the leak and, if necessary, any additional attempt to repair the leak;*
> *XVII.F.8.e. The date the leak was repaired;*
> *XVII.F.8.f. The delayed repair list, including the basis for placing leaks on the list;*
> *XVII.F.8.g. The date the leak was remonitored to verify the effectiveness of the repair, and the results of the remonitoring; and*
> *XVII.F.8.h. A list of components that are designated as unsafe, difficult, or inaccessible to monitor, as described in Section XVII.F.5., an explanation stating why the component is so designated, and the plan for monitoring such component(s)."*

API request that minimal records be required to reduce the cost and burden of this rule similar to what Colorado Regulation 7 requires. Further information is not needed to ensure compliance with the leak detection and repair requirements.

Also, API requests that minimal reporting of the leaks be required. Colorado Regulation 7 simply requires that the following information be reported:

> *"XVII.F.9. Reporting: The owner or operator of each facility subject to the leak detection and repair requirements in Section XVII.F. must submit a single annual report on or before May 31st of each year that includes, at a minimum, the following information regarding leak detection and repair activities at their subject facilities conducted the previous calendar year:*
> *XVII.F.9.a. The number of facilities inspected;*
> *XVII.F.9.b. The total number of inspections;*
> *XVII.F.9.c. The total number of leaks identified, broken out by component type;*
> *XVII.F.9.d. The total number of leaks repaired;*
> *XVII.F.9.e. The number of leaks on the delayed repair list as of December 31st; and"*

27.6.6 Recommended Text Revisions Associated With Reporting and Recordkeeping Requirements.

§60.5397a(k)(6)(ii) ~~One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the well site or compressor station imbedded within or stored with the digital file. 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.~~

§60.5420a(b)(7) For the collection of fugitive emissions components at a well site and the collection of fugitive emissions components at a compressor station or central production site for a corporation or area, the records of each monitoring survey conducted during the year:

(i) The number of facilities inspected
(ii) The total number of inspections
(iii) The total number of leaks identified broken out by component type
(iv) The total number of leaks repaired
(v) The total number of leaks on the delay of repair list as of December 31st

~~(i) Date of the survey.~~
~~(ii) Beginning and end time of the survey.~~
~~(iii) Name of operator(s) performing survey. If the survey is performed by optical gas imaging, you must note the training and experience of the operator.~~
~~(iv) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.~~

~~(v) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.~~
~~(vi) Documentation of each fugitive emission, including the information specified in paragraphs (b)(7)(vi)(A) through (C) of this section~~

~~(A) Location.~~
~~(B) One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station imbedded within or stored with the digital file. 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.~~
~~(C) The date of successful repair of the fugitive emissions component.~~
~~(D) Type of instrument used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.~~

§60.5420a(c)(15) For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station, the records identified in paragraphs (c)(15)(i) and (ii) of this section.
(i) ~~The fugitive emissions~~ The corporate-wide or area-wide monitoring plan ~~for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station as required in §60.5397a(a~~).
(ii) The records of each monitoring survey as specified in paragraphs (c)(15)(ii)(A) through (F) of this section.
(A) Date of the survey.
(B) Location of the survey
(C) A list of leaking components
(D) The date of the first attempt to repair and additional attempts to repair
(E) The date the leak was repaired
(F) The delay of repair list including the basis for placing leaks on the list
(G) The date the leak was remonitored to verify the effectiveness of the repair

~~(B) Beginning and end time of the survey.~~
~~(C) Name of operator(s) performing survey. You must note the training and experience of the operator.~~
~~(D) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.~~
~~(E) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.~~
~~(F) Documentation of each fugitive emission, including the information specified in paragraphs (c)(15)(ii)(F)(1) through (2) of this section.~~
~~(1) Location.~~
~~(2) One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken~~

~~taken and the latitude and longitude of the collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station imbedded within or stored with the digital file. 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.~~

~~(3) The date of successful repair of the fugitive emission component.~~

~~(4) Instrumentation used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.~~

Attachment A
API's Recommended Rule Language

Throughout the comments API has provided recommended rule language to assist EPA in making the necessary corrections to respond to the issues raised. These changes have been provided in redline/strikeout format. A consolidated version of all regulatory changes is provided within this Attachment as reference. If there are any discrepancies in this consolidated summary and the markups shown in the comments, those provided in the comments should be taken as our preferred position. For each section of Subpart OOOOa where regulatory changes are suggested, the sections of this document where these recommendations originate are provided in [blocked parentheses].

40 CFR PART 98, Subpart OOOOa

§60.5363a [SEE SECTION 6.0]

§60.5363a 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 emission 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).
(2) For the purposes of 40 CFR 52.21(b)(50)(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 § 52.21(b)(49) of this chapter.
(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.
(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.

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§60.5365a [SEE SECTIONS 20.0; 22.2.2; 22.2.3; 24.3.3; 24.4.1; 24.4.5; 25.1; 25.2; 27.2.12]

(a) Each well affected facility, which is a single well that conducts a well completion operation following hydraulic fracturing or refracturing and has a gas-to-oil ratio less than 300 scf of gas per stock tank barrel of oil produced. Wells that must use artificial lift equipment to flowback completion fluid are not well affected facilities.

* * * * *

(a)(5) A well completion operation in compliance with a legally and practically enforceable requirement that requires the reduction of VOC or methane is not an affected facility.

(b) Each centrifugal compressor affected facility, which is a single centrifugal compressor using wet seals. A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart. A centrifugal compressor in compliance with a legally and practically enforceable requirement that requires at least a 95% reduction in VOC or methane emissions is not an affected facility.

(c) Each reciprocating compressor affected facility, which is a single reciprocating compressor. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart. A reciprocating compressor in compliance with a legally and practically enforceable requirement that requires the reduction of VOC or methane is not an affected facility.

(e) Each storage vessel affected facility, which is a single storage vessel with the potential for VOC emissions equal to or greater than 6 tpy as determined according to this section, except as provided in paragraphs (e)(1) through (4) of this section. The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline specified in paragraph (e)(1) of this section. The determination may take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a Federal, State, local or tribal authority.

(e)(1) For each new, modified or reconstructed storage vessel receiving liquids pursuant to the standards for well affected facilities in §60.5375a, including wells subject to §60.5375a(f), you must determine the potential for VOC emissions within 30 days after startup of production (i.e., the date that the storage vessel is placed into service).

* * * * *

(4)~~For each new, reconstructed, or modified storage vessel with startup, startup of production, or which is returned to service, affected facility status is determined as follows: If a storage vessel is reconnected to the original source of liquids or is used to replace any storage vessel affected facility, it is a storage vessel affected facility subject to the same requirmeents as before being removed from service, or applicable to the storage vessel affected facility beig replaced, immediately upon startup, startup of production, or return to service.~~ Each storage vessel that was constructed, reconstructed, or modified after September 18, 2015 that replaces an existing storage vessel shall determine applicability according to the provisions in (e)(4)(i) or (ii).

(i) If the storage vessel being replaced is a storage vessel affected facility, the new storage vessel is an affected facility.

(ii) If the storage vessel being replaced is not a storage vessel affected facility, applicability shall be determined in accordance with paragraph (e) and (e)(1) of this section.

(5) Each storage vessel affected facility formerly subject to Subpart OOOOa that was removed from service in accordance with §60.5395a(c) that is put back into service shall determine applicability according to the provisions in (e)(5)(i) or (ii).

(i) If the storage vessel is reconnected to the original source of liquids, it is a storage vessel affected facility subject to the same requirements as before being removed from service.

(ii) If the storage vessel is put back into service and not reconnected to the original source of liquids, applicability shall be determined in accordance with paragraph (e)(4) of this section.

(6) For the purposes of this Subpart, after the initial applicability determination for a storage vessel has been conducted in accordance with the requirements of paragraph (e) and (e)(1), situations that increase the throughput of that storage vessel shall not be considered modifications and shall not require a new applicability determination.

* * * * *

(h)(1) For natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven ~~chemical/methanol~~ pump with an exhaust rate greater than 53,000 scf/yr ~~or a natural gas-driven diaphragm pump~~ ~~and~~ that operates more than 2,160 hours per year.

(h)(2) *For locations other than natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven chemical/methanol pump or a natural gas-driven diaphragm pump that meets the criteria in paragraphs (i) through (iii) and is not excluded by (iv).*

(i) *The pump has an exhaust rate greater than 53,000 scf/yr and operates more than 2,160 hours per year.*

(ii) *The pump has a control device owned and operated by the owner and operator of the pump is located on site. For the purpose of this section, boilers, process heaters, and other combustion devices that burn natural gas to derive useful work or heat are not considered control devices.*

(iii) *The pump has not been demonstrated to be technically infeasible to control.*

(iv) *A pneumatic pump that is in compliance with a legally and practically enforceable requirement that requires the reduction of VOC or methane is not an affected facility.*

(i) Except as provided in §60.5365a(i)(1) through (i)(~~2~~5), the collection of fugitive emissions components at a new, modified, or reconstructed well site, as defined in § 60.5430a, is an affected facility.

(1) A well site with 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 or for any 12 consecutive month period after startup of production, is not an affected facility under this subpart.

(2) Any well site or process unit with a GOR less than 300 during the first 30 days of production or for any 1 year period after startup of production is not an affected facility.

(3) Any oil well site requiring mechanical artificial lift such as a rod pump or submersible pump with no associated gas gathering system is not an affected facility.

(4) Well sites with a legally and practically enforceable leak detection and repair requirement in an operating permit or other enforceable requirement established under a Federal, State, local or tribal authority are not affected facilities in this subpart.

(~~2~~5) A well site with one or more wellheads that does not ~~only contain~~ include installation of at least one of the following: a separator, heater, or glycol dehydrator ~~one or more wellheads~~ is not an affected facility under this subpart.

(6) A well site that produces oil with either an API gravity less than 18˚ or a GOR less than 300 scf/bbl is not an affected facility under this subpart

(7) An EOR wellsite is not an affected facility under this subpart

(~~3~~8) For purposes of § 60.5397a, a ''modification'' to a well site occurs when an additional well head, separator, heater, or dehydrator is installed.

~~(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.~~

(j) The collection of new, modified, or reconstructed fugitive emissions components at a central production site or transmission compressor station site , as defined in §60.5430a, is an affected facility. The collection of fugitive emissions components at a compressor station or central production site in an EOR field is not an affected facility.

(1) Central production sites and transmission compressor station sites with a legally and practically enforceable leak detection and repair requirement in an operating permit or other enforceable requirement established under a Federal, State, local or tribal authority are not affected facilities in this subpart.

(2) For purposes of § 60.5397a, a ''modification'' to a compressor station or central production site occurs when:

(i) An additional new, modified, or reconstructed compressor is installed at an existing transmission compressor station or central production site that results in an increase in emissions of a compressor station or central production site

(ii) A physical change is made to an existing compressor at a transmission compressor station or central production site that increases the ~~compression capacity of~~ emissions at the transmission compressor station or central production site.

(iii) An additional new, modified, or reconstructed separator, heater, or dehydrator is installed at a central production site.

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§60.5375a [SEE SECTIONS 22.2.4 AND 22.2.5]

(a)(1)(i): During the initial flowback stage, route the flowback into one or more well completion vessels or storage vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the initial flowback stage is not subject to control under this section. A separator is not required to be located onsite during the initial flowback stage. Once conditions allow for separation, then the operate must immediately stop the well completion operation, install a separator, and restart the well completion operation in the separation flowback stage.

* * * * *

(3) You must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways or it is technically infeasible due to inert gas concentration.

* * * * *

f)(2) You must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways or it is technically infeasible due to inert gas concentration.

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§60.5385a [SEE SECTION 23.1]

(a)(3) *Collect the emissions from the rod packing using a rod packing emissions collection system ~~which operates under negative pressure~~ and route the rod packing emissions to a process through a closed vent system...*

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§60.5393a [SEE SECTION 24.5.1]

~~(a)(2): Each pneumatic pump affected facility at 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 pneumatic pump as required in § 60.5420a(c)(16)(i).~~

* * * * *

~~(b)(3) 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 § 60.5420a(c)(16)(i).~~

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§60.5395a [SEE SECTIONS 25.5 AND 25.6]

(a)(3) Maintain the uncontrolled actual VOC emissions from the storage vessel affected facility at less than 4 tpy without considering control. Prior to using the uncontrolled actual VOC emission rate for compliance purposes, you must demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy as determined monthly for 12 consecutive months. After such demonstration, you must determine the uncontrolled actual VOC emission rate each month. The uncontrolled actual VOC emissions must be calculated using a generally accepted model or calculation methodology, and the calculations must be based on the average throughput for the month. You must comply with paragraph (a)(2) of this section within 30 days of the monthly determination if ~~your storage vessel affected facility meets the conditions specified in paragraphs (a)(3)(i) or (ii) of this section.~~

~~(i) If a well feeding the storage vessel affected facility undergoes fracturing or refracturing, you must comply with paragraph (a)(2) of this section as soon as liquids from the well following fracturing or refracturing are routed to the storage vessel affected facility.~~

~~(ii) If~~ the monthly emissions determination required in this section indicates that VOC emissions from your storage vessel affected facility increase to 4 tpy or greater ~~and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel affected facility, you must comply with paragraph (a)(2) of this section within 30 days of the monthly determination~~.

(b) Control requirements. (1) Except as required in paragraph (b)(2) of this section, if you use a control device to reduce VOC emissions from your storage vessel affected facility, you 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). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process ~~that reduces VOC emissions by at least 95.0 percent~~.

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§60.5397a [SEE SECTIONS 26.4; 27.3.11; 27.4.14; 27.5.6; 27.6.6]

(a) You must monitor all fugitive emission components, as defined in 60.5430a, in accordance with paragraphs (b) through (i) of this section. You must repair all sources of fugitive emissions in accordance with paragraph (j) of this section. You must keep records in accordance with paragraph (k) and report in accordance with paragraph (l) of this section. For purposes of this section, fugitive emissions are defined as: Any visible emission from a fugitive emissions component observed using optical gas imaging or approved alternative detection device under paragraph (m) of this section.

* * * * *

(b) You must develop a corporate-wide or area-wide fugitive emissions monitoring plan that covers the collection of fugitive emissions components at well sites and compressor stations in accordance with paragraph (c) of this section.~~, and you must develop a site specific fugitive emissions monitoring plan specific to each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station in accordance with paragraph (d) of this section. Alternatively, you may develop a site-specific plan for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station that covers the elements of both the corporate-wide and site-specific plans.~~

(c) Your corporate-wide or area-wide monitoring plan must include the elements specified in paragraphs (c)(1) through (8) of this section, as a minimum.

(1) Frequency for conducting surveys. Surveys must be conducted at least as frequently as required by paragraphs (f) through (i) of this section.

(2) Technique for determining fugitive emissions.

(3) Manufacturer and model number of fugitive emissions detection equipment to be used.

(4) Procedures and timeframes for identifying and repairing fugitive emissions components from which fugitive emissions are detected, including timeframes for fugitive emission components that are unsafe to repair. Your repair schedule must meet the requirements of paragraph (j) of this section at a minimum.

(5) Procedures and timeframes for verifying fugitive emission component repairs.

(6) Records that will be kept and the length of time records will be kept.

(7) Your plan must also include the elements specified in paragraphs (c)(7)(i) through (vii) of this section.

~~(i) Verification that your optical gas imaging equipment meets the specifications of paragraphs (c)(7)(i)(A) and (B) of this section. This verification is an initial verification and may either be performed by the facility, by the manufacturer, or by a third party. For the purposes of complying with the fugitives emissions monitoring program with optical gas imaging, a fugitive emission is defined as any visible emissions observed using optical gas imaging.~~

~~(A) Your optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions.~~

~~(B) Your optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of ≤10,000 ppm at a flow rate of ≥60g/hr from a quarter inch diameter orifice.~~

~~(ii) Procedure for a daily verification check.~~

(i)~~(iii)~~ Procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained.

(ii)~~(iv)~~ Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold.

(iii)~~(v)~~ Procedures for conducting surveys, including the items specified in paragraphs (c)(7)(v)(A) through (C) of this section.

(A) How the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions.

(B) How the operator will deal with adverse monitoring conditions, such as wind.

(C) How the operator will deal with interferences (e.g., steam).

(iv)~~(vi)~~ Training and experience needed prior to performing surveys.

(v)(~~vii~~) Procedures for calibration and maintenance. Procedures must comply with those recommended by the manufacturer.

~~(d)~~ Reserved ~~Your site-specific monitoring plan must include the elements specified in paragraphs (d)(1) through (3) of this section, as a minimum.~~

~~(1) Deviations from your master plan.~~

~~(2) Sitemap.~~

~~(3) Your plan must also include your defined walking path. The walking path must ensure that all fugitive emissions components are within sight of the path and must account for interferences.~~

(e) Each monitoring survey shall observe each piece of equipment with fugitive emissions components for fugitive emissions.

(f)(1) You must conduct an initial monitoring survey within ~~30~~180 days of the first date of production ~~the first well completion~~ for each collection of fugitive emissions components at a new well site ~~or upon the date the well site begins the production phase for other wells~~. For a modified collection of fugitive emissions components at a well site, the initial monitoring survey must be conducted within ~~30~~180 days of the well site modification.

(2) You must conduct an initial monitoring survey within ~~30~~180 days of the startup of a new compressor station or central production site for each new collection of fugitive emissions components at the new compressor station or central production site. For modified compressor stations or central production site, the initial monitoring survey of the collection of fugitive emissions components at a modified compressor station must be conducted within ~~30~~ 90 days of the modification. For affected facility sites constructed between Sept. 18, 2015 and 60 days after [final date of rule], initial surveys must be completed by [insert one year and 60 days after final rule promulgation]

(g) A monitoring survey of each collection of fugitive emissions components at a well site and collection of fugitive emissions components at a transmission compressor station or central production site shall be conducted ~~at least semi~~annually after the initial survey. Consecutive ~~semi~~-annual monitoring surveys shall be conducted at least 49 months apart.

(h) ~~The monitoring frequency specified in paragraph (g) of this section shall be increased to quarterly in the event that two consecutive semiannual monitoring surveys detect fugitive emissions at greater than 3.0 percent of the fugitive emissions components at a well site or at greater than 3.0 percent of the fugitive emissions components at a compressor station~~. The initial and subsequent monitoring surveys specified in paragraphs (f) and (g) of this section must be conducted using one of the following methods:

(1) Optical gas imaging equipment.

(2) Method 21 (including soap bubbles or SNOOP as specified in Method 21, Section 8.3.3).

(3) A method that the company keeps records to demonstrate that is equivalent in detecting leaks to either of the methods specified in paragraphs (h)(1) or (h)(2) of this section.

(4) Screening methods, including but not limited to Tunable Diode Laser Absorption Spectroscopy (TDLAS), Interference Polarization Spectrometer (IR-CIPS), or Differential Absorption Light Detection and Ranging (DIAL LiDAR) technology, that screen for no leaks. If these methods do not detect a leak, then that survey is considered to have identified no leaks. However, if a leak is identified by one of these screening methods, then a monitoring method specified in paragraph (h)(1), (h)(2), or (h)(3) of this section must be used to confirm the presence of the leak.

(i) Reserved ~~The monitoring frequency specified in paragraph (g) of this section may be decreased to annual in the event that two consecutive semiannual surveys detect fugitive emissions at less than 1.0~~

~~percent of the fugitive emissions components at a well site, or at less than 1.0 percent of the fugitive emissions components at a compressor station. The monitoring frequency shall return to semiannual if a survey detects fugitive emissions between 1.0 percent and 3.0 percent of the fugitive emissions components at the well site, or between 1.0 percent and 3.0 percent of the fugitive emissions components at the compressor station.~~

(j) ~~For fugitive emissions components also subject to the repair provisions of §§60.5416a(b)(9) through (12) and (c)(4) through (7), those provisions apply instead to those closed vent system and covers, and the repair provisions of paragraphs (j)(1) and (2) of this section do not apply to those closed vent systems and covers.~~ You must comply with the requirements of paragraphs (j)(1) and (2) of this section.

(j)(1) Each identified source of fugitive emissions shall be repaired or replaced as soon as practicable, but no later than ~~15~~30 calendar days after detection of the fugitive emissions. If the repair or replacement is technically infeasible or unsafe ~~to repair during operation of the unit~~, the repair or replacement must be completed during the next scheduled shutdown ~~or within 6 months, whichever is earlier~~.

(2)(i) For repairs that cannot be made during the monitoring survey when the fugitive emissions are initially found, the operator may resurvey the repaired fugitive emissions components using ~~either Method 21 or optical gas imaging~~ one of the methods specified in §60.5397a(h) within 15 days of ~~finding such~~ repairing the fugitive emission~~s~~ source.

* * * * *

(ii)(A) A fugitive emissions component is repaired when the Method 21 instrument indicates a concentration of less than ~~500~~10,000 ppm above background.

* * * * *

~~(k)(6)(ii) One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the well site or compressor station imbedded within or stored with the digital file. 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.~~

* * * * *

(m) Alternative detection devices that can meet the criteria in §60.5397(m)(1) through (5) of this section can be submitted for approval for use by the Administrator or delegated authority. The alternative is considered approved and can be used for compliance with this subpart if there is no response from the Administrator or delegated authority within 180 days of a complete submittal::
(1) Occurs at least annually
(2) Pinpoints the general location of the leak
(3) Is capable of detecting the hydrocarbons found at the site
(4) Testing and certification are repeatable
(5) Information on the limitations, other applications, how the devices works, how it will be used, and the process for recordkeeping and training are provided.

§60.5401a [SEE SECTION 12.5.6]

(h) For a flare that is subject to §60.18 via §60.482-10a(d), the volumetric flowrate used to calculate the actual exit velocity in §60.18(f)(4) may be determined using engineering calculations based on conditions that reflect representative performance of the process unit. In addition, the velocity limits in §60.18(c)(3) do not apply during periods of emergency, upset, or maintenance.

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§60.5410a [SEE SECTIONS 24.4.8; 24.5.1; 26.4]

(b)(4) You must conduct the initial ~~inspections~~ monitoring survey required in ~~§60.5416a(a) and (b)~~§60.5397(j).
(e)(3) Reserved ~~You own or operate a pneumatic pump affected facility located other than at a natural gas processing plant and your pneumatic pump is not controlled by at least 95 percent because a control device is not available at the site, you must submit the certification in 60.5420a(b)(8)(i).~~
(e)(4) Reserved ~~You must tag each new pneumatic pump affected facility according to the requirements of § 60.5393a(a)(2) or (b)(3).~~

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§60.5411a [SEE SECTOINS 14.3 AND 26.4]

(a)(2) You must design and operate the closed vent system with no detectable emissions as demonstrated by ~~§60.5416a(b)~~ complying with the requirements for fugitive emission components in §60.5397.
(3)(i)(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and/or visible alarm~~, and initiate notification via remote alarm to the nearest field office,~~ when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is discovered ~~activated~~ according to §60.5420a(c)(8).
* * * * *
(c)(3)(i)(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and/or visible alarm~~, and initiate notification via remote alarm to the nearest field office,~~ when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is discovered ~~sounded~~ according to §60.5420a(c)(8).

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§60.5412a [SEE SECTIONS 12.5.6; 12.6; AND 13.2]

You must meet the applicable requirements of this section for each control device used to comply with the emission standards for your centrifugal compressor affected facility, pneumatic pump affected facility, or storage vessel affected facility. Control devices in compliance with the requirements in §63.771 of 40 CFR 63, Subpart HH are exempt from the requirements in this Subpart.
(a) Each control device used to meet the emission reduction standard in §60.5380a(a)(1) for your centrifugal compressor affected facility or §60.5393a(b)(1) for your pneumatic pump must be installed according to paragraphs (a)(1) through (3) of this section. As an alternative, you may install a combustion

control device model tested under §60.5413a(d), w except for flare which meets the criteria in §60.5413a(d)(11) and §60.5413a(e).

(1) Each combustion control device ~~(e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater)~~ except for flare must be designed and operated in accordance with one of the performance requirements specified in paragraphs (a)(1)(i) through (~~iv~~iii) of this section.

* * * * *

~~(iv) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.~~

* * * * *

(d) Each control device used to meet the emission reduction standard in §60.5395a(a) for your storage vessel affected facility must be installed according to paragraphs (d)(1) through (4) of this section, as applicable. As an alternative to paragraph (d)(1) of this section, you may install a combustion control device model tested under §60.5413a(d), which meets the criteria in §60.5413a(d)(11) and §60.5413a(e).

(1) For each enclosed combustion control device ~~(e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater)~~ you must meet the requirements in paragraphs (d)(1)(i) through (iv) of this section.

* * * * *

(iv) Each combustion control device ~~(e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater)~~ must be designed and operated in accordance with one of the performance requirements specified in paragraphs (A) through (~~D~~C) of this section.

* * * * *

~~(D) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.~~

* * * * *

(3) You must design and operate a flare in accordance with the requirements of §60.5413a.

(~~3~~4) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes from working or flash losses are vented from the storage vessel affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

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§60.5413a [SEE SECTIONS 12.5.6; 12.7; AND 13.2]

(a)Performance test exemptions. You are exempt from the requirements to conduct performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through (~~7~~5) of this section.

(1) A flare that is designed and operated in accordance with §60.18(b), with the exceptions noted in paragraphs (a)(1)(i) through (iii) of this section. You must conduct the compliance determination using Method 22 of appendix A-7 of this part to determine visible emissions.

(i) A flare that is equipped with an electronic ignition system will satisfy the requirements in §60.18(c)(2) and (e),

(ii) The volumetric flowrate used to calculate the actual exit velocity in §60.18(f)(4) may be determined using engineering calculations based on conditions that reflect representative performance of the centrifugal compressor, pneumatic pump, or storage vessel affected facility, and

(iii) During periods of emergency, upset, or maintenance, the velocity limits in §60.18(c)(3) do not apply.

~~(2) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.~~

~~(3) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel.~~

(~~4~~2) A boiler or process heater burning hazardous waste for which you have either been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 266, Subpart H; or you have certified compliance with the interim status requirements of 40 CFR part 266, Subpart H.

(~~5~~3) A hazardous waste incinerator for which you have been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 264, Subpart O; or you have certified compliance with the interim status requirements of 40 CFR part 265, Subpart O.

(~~6~~4) A performance test is waived in accordance with §60.8(b).

(~~7~~5) A combustion control device whose model can be demonstrated to meet the performance requirements of §60.5412a(a) or (d) through a performance test conducted by the manufacturer, as specified in paragraph (d) of this section.

(b)(1)(ii) The sampling site must be located at the outlet of the combustion device to determine compliance with the enclosed combustion control device total TOC concentration limit specified in §60.5412a(a)(1)(ii).

(b)(3)(iv) Reserved ~~If the vent stream entering a boiler or process heater with a design capacity less than 44 megawatts is introduced with the combustion air or as a secondary fuel, you must determine the weight-percent reduction of total TOC (minus methane and ethane) across the device by comparing the TOC (minus methane and ethane) in all combusted vent streams and primary and secondary fuels with the TOC (minus methane and ethane) exiting the device, respectively.~~

* * * * *

(d)(2) Performance testing must consist of three 1-hour (or longer) test runs for each of the four firing rate settings specified in paragraphs (d)(2)(i) through (iv) of this section, making a total of 12 test runs per test. ~~Propene (propylene)~~ Propane gas must be used for the testing fuel. All fuel analyses must be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

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§60.5415a [SEE SECTION 26.4]

(e)(3)(ii)(A) You must comply with ~~§60.5416a(c)~~ the requirements for fugitive emission components in §60.5397a for each cover and closed vent system.

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§60.5416a [SEE SECTION 26.2.1]

Remove Section 60.5416a

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§60.5417a [SEE SECTIONS 12.5.7 AND 13.2]

(b) Reserved ~~You are exempt from the monitoring requirements specified in paragraphs (c) through (g) of this section for the control devices listed in paragraphs (b)(1) and (2) of this section.~~

~~(1) A boiler or process heater in which all vent streams are introduced with the primary fuel or are used as the primary fuel.~~

~~(2) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.~~

* * * * *

(d)(1) (iii) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the ~~continuous ignition of the pilot flame~~ presence of a flame as required in §60.5412(d)(4).

(iv) Reserved ~~For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5°C, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.~~

* * * * *

(viii) (A) The continuous monitoring system must measure gas flow rate at the inlet to the combustion control device. The monitoring instrument must have an accuracy of ±2 percent or better. The flow rate at the inlet to the combustion control device must not exceed the maximum or be less than the minimum flow rate determined by the manufacturer.

(B) A monitoring device that continuously indicates the presence of the pilot flame while emissions are routed to the combustion control device.

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§60.5420a [SEE SECTIONS 24.4.8; 24.5.2; 26.4; 27.6.6]

(b)(7) For the collection of fugitive emissions components at a well site and the collection of fugitive emissions components at a compressor station or central production site for a corporation or area, the records of each monitoring survey conducted during the year:
(vi) The number of facilities inspected
(vii) The total number of inspections
(viii) The total number of leaks identified broken out by component type
(ix) The total number of leaks repaired
(x) The total number of leaks on the delay of repair list as of December 31st

~~(i) Date of the survey.~~
~~(ii) Beginning and end time of the survey.~~
~~(iii) Name of operator(s) performing survey. If the survey is performed by optical gas imaging, you must note the training and experience of the operator.~~
~~(iv) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.~~
~~(v) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.~~
~~(vi) Documentation of each fugitive emission, including the information specified in paragraphs (b)(7)(vi)(A) through (C) of this section~~

~~(B) Location.~~
~~(B) One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station imbedded within or stored with the digital file. 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.~~
~~(C) The date of successful repair of the fugitive emissions component.~~
~~(D) Type of instrument used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.~~

* * * * *

(b)(8)(i): Reserved ~~In the initial annual report, a certification that there is no control device on site, if applicable.~~

* * * * *

~~(v) If complying with §60.5393a(b)(1) with a control device tested under §60.5413(d), which meets the criteria in §60.5413(d)(11) and §60.5413(e), records specified in paragraphs (c)(16)(iv)(A) through (G) of this section for each pneumatic pump constructed, modified or reconstructed during the reporting period.~~

* * * * *

(c)(5)(i) If required to reduce emissions by complying with §60.5395a(a)(2), the records specified in §§60.5420a(c)(6) through (8)~~, 60.5416a(c)(6)(ii), and 60.5416a(c)(7)(ii)~~. You must maintain the records in paragraph (c)(5)(vi) of this part for each control device tested under §60.5413a(d) which meets the criteria in §60.5413a(d)(11) and §60.5413a(e) and used to comply with §60.5395a(a)(2) for each storage vessel.

(6) Records of each closed vent system and cover inspection monitoring survey required under ~~§60.5416a(a)(1) and (a)(2)~~§60.5397a(f)(g),(h) or (i) for centrifugal compressors, reciprocating compressors and pneumatic pumps, or §60.5416a(c)(1) for storage vessels.

(7) Reserved ~~A record of each cover inspection required under §60.5416a(a)(3) for centrifugal or reciprocating compressors or §60.5416a(c)(2) for storage vessels.~~

(8) Reserved ~~If you are subject to the bypass requirements of §60.5416a(a)(4) for centrifugal compressors, reciprocating compressors or pneumatic pumps, or §60.5416a(c)(3) for storagevessels, a record of each inspection or a record of each time the key is checked out or a record of each time the alarm is sounded.~~

(9) If you are subject to the closed vent system no detectable emissions requirements of ~~§60.5416a(b)~~ §60.5397a for centrifugal compressors, reciprocating compressors or pneumatic pumps, a record of the monitoring conducted in accordance with ~~§60.5416a(b)~~ §60.5397a(k).

* * * * *

(15) For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station, the records identified in paragraphs (c)(15)(i) and (ii) of this section.

(ii) ~~The fugitive emissions~~ <u>The corporate-wide or area-wide</u> monitoring plan ~~for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station as required in §60.5397a(a~~).

(ii) The records of each monitoring survey as specified in paragraphs (c)(15)(ii)(A) through (F) of this section.

(H) Date of the survey.

(I) <u>Location of the survey</u>

(J) <u>A list of leaking components</u>

(K) <u>The date of the first attempt to repair and additional attempts to repair</u>

(L) <u>The date the leak was repaired</u>

(M) <u>The delay of repair list including the basis for placing leaks on the list</u>

(N) <u>The date the leak was remonitored to verify the effectiveness of the repair</u>

~~(B) Beginning and end time of the survey.~~

~~(C) Name of operator(s) performing survey. You must note the training and experience of the operator.~~
~~(D) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.~~
~~(E) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.~~
~~(F) Documentation of each fugitive emission, including the information specified in paragraphs (c)(15)(ii)(F)(1) through (2) of this section.~~
~~(1) Location.~~
~~(2) One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station imbedded within or stored with the digital file. 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.~~
~~(3) The date of successful repair of the fugitive emission component.~~
~~(4) Instrumentation used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.~~

§60.5420a(c)(16) For each pneumatic pump affected facility, you must maintain the records identified in paragraphs (c)(1)(i) through (iv) of this section.

(i) Records of the date, location and ~~manufacturer specifications~~ make and model for each pneumatic pump constructed, modified or reconstructed.
(ii) Records of deviations in cases where the pneumatic pump was not operated in compliance with the requirements specified in §60.5393a.
(iii) ~~Records of the control device installation date and the location of sites containing pneumatic pumps at which a control device was installed, where previously there was no control device at the site.~~
(iv) ~~Except as specified in paragraph (c)(16)(iv)(G) of this section, records for each control device tested under §60.5413a(d) which meets the criteria in §60.5413a(d)(11) and §60.5413a(e) and used to comply with §60.5393a(b)(1) for each pneumatic pump.~~
  - ~~(A) Make, model and serial number of purchased device.~~
  - ~~(B) Date of purchase.~~
  - ~~(C) Copy of purchase order.~~
  - ~~(D) Location of the pneumatic pump and control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.~~
  - ~~(E) Inlet gas flow rate.~~
  - ~~(F) Records of continuous compliance requirements in §60.5413a(e) as specified in paragraphs (c)(16)(iv)(F)(1) through (4) of this section.~~
    - ~~(1) Records that the pilot flame is present at all times of operation.~~
    - ~~(2) Records that the device was operated with no visible emissions except for periods not to exceed a total of 2 minutes during any hour.~~
    - ~~(3) Records of the maintenance and repair log.~~
    - ~~(4) Records of the visible emissions test following return to operation from a maintenance or repair activity.~~

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§60.5430a Definitions [SEE SECTIONS 13.1.2; 13.2; 22.1; 22.2.3; 24.4.3; 25.4; 26.1; 26.2; 27.2.12]

Artificial Lift Equipment means the use of mechanical pumps (e.g., rod pumps or electric submersible pumps) to flowback fluids from a well.

Capital expenditure:

Central production site means one or more contiguous surface sites with no wellheads and with a collection of either one or more gathering or boosting natural gas compressors, one or more crude oil or condensate storage vessels, or both that process crude oil or natural gas and located between a well site and natural gas processing plant or natural gas transmission line, but is not co-located with a well head.

~~"Chemical/methanol or diaphragm pump means a gas-driven positive displacement pump typically used to inject precise amounts of chemicals into process streams or circulate glycol compounds for freeze protection."~~

Closed-vent system means 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 **except for components and other openings on the cover of the equipment** shall not be considered a closed-vent system and is not subject to closed-vent system standards.

Control device means any equipment used for recovering or oxidizing volatile organic compound (VOC) or methane emissions. Such equipment includes, but is not limited to, absorbers, carbon adsorbers, condensers, and combustion devices. Recovery devices that recycle the emissions back to the process, and combustion devices that use the emissions as fuel gas, are not considered control devices under this Subpart.

Combustion control device means a thermal vapor incinerator, catalytic vapor incinerator, flare, or other combustion device that do not burn emissions as a fuel gas.

Enclosed combustion control device means a combustion control device with an enclosure such that the flame is not an open flame.

Fuel gas means gases that are combusted to derive useful work or heat.

Fugitive emissions component means each pump, pressure relief device, open-ended valve or line, valve, flange or other connector that is in VOC or natural gas service at a well site, central production site, or transmission compressor station but not including a natural gas processing plant process unit. ~~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 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.~~

Low pressure 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.

> *"Maximum average daily throughput means the ~~earliest calculation of~~ daily average throughput during the 30-day PTE evaluation period that represents steady-state conditions~~employing generally accepted methods~~."*

Natural gas-driven chemical/methanol pump or natural gas-driven diaphragm pump means a natural gas-driven positive displacement pump used to inject chemicals into process streams or circulate glycol compounds for freeze protection. A lean glycol circulation pump on a glycol dehydration unit is not a chemical/methanol or diaphragm pump. A temporary or portable pump is considered a stationary source under this rule if the stays in one location for more than 12 months (or full annual operating period of a seasonal source).

Optical gas imaging instrument means an instrument that makes visible emissions that may otherwise be invisible to the naked eye. Optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions imaging a gas that is half methane, half propane at a concentration of >10,000 ppm.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered. Emissions used as fuel gas in a boiler, process heater, or other combustion device are considered to be routed to a process.

Well site means one or more contiguous ~~areas~~ surface sites that are ~~directly~~ constructed ~~disturbed during~~ for the drilling and subsequent operation of an oil or natural gas well, and any~~affected by~~ production facilities directly associated with any oil well or natural gas well. ~~or injection wel~~l ~~located on a 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, or produced water from wells not located at the well site (e.g., centralized tank batteries).~~

Tables to Subpart OOOO [SEE SECTION 12.5.7]

Table 3 to Subpart OOOOa of Part 60 – Applicability of General Provisions to Subpart OOOO

General provisions citation	Subject of citation	Applies to subpart?	Explanation
§ 60.18	General control device and work practice requirements	Yes	Except that (1) A flare that is equipped with an electronic ignition system will satisfy the requirements in §60.18(c)(2). (2) The volumetric flowrate used to calculate the actual exit velocity in §60.18(f)(4) may be determined using engineering calculations based on conditions that reflect representative performance of the centrifugal compressor, pneumatic pump, or storage vessel affected facility. (3) During periods of emergency, upset, or maintenance, the velocity limits in §60.18(c)(3) do not apply.

Attachment B

API's Comments on EPA's NSPS Electronic Reporting Proposal

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EPA Document Center (EPA/DC)
Environmental Protection Agency (Mail Code 28221T)
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EPA Desk Officer
Office of Information and Regulatory Affairs
Office of Management and Budget (OMB)
Attn: Desk Officer for EPA
725 17th Street NW
Washington DC 20503

Attention: Docket ID: EPA–HQ–OAR–2009–0174

Re: Environmental Protection Agency's (EPA's) "Electronic Reporting and Recordkeeping Requirements for New Source Performance Standards: Proposed Rule" 80 Fed. Reg. 15100 (March 20, 2015).

The American Petroleum Institute (API) submits the attached comments on the Environmental Protection Agency's (EPA's) "Electronic Reporting and Recordkeeping Requirements for New Source Performance Standards: Proposed Rule" published in the Federal Register on March 20, 2015 at 80 Fed. Reg. 15100.

The American Petroleum Institute ("API") represents over 650 oil and natural gas companies, leaders of a technology-driven industry that supplies most of America's energy, supports more than 9.8 million jobs and 8 percent of the U.S. economy, and, since 2000, has invested nearly $2 trillion in U.S. capital projects to advance all forms of energy, including alternatives.

API members are involved with all aspects of the oil and natural gas industry, including the production of chemicals. Member facilities will be directly impacted by the provisions of the current proposal because of the large number of part 60 standards applicable to member company facilities and the precedents being established for recordkeeping and reporting requirements in general.

This proposal suffers from a failure to address the realities of reporting using an inflexible and difficult to revise electronic system, the realities of the structure of EPA regulations and EPA's practice of referencing part 60 paragraphs and subparts, and the difficulties of integrating EPA's electronic reporting system into existing EPA, State and company reporting processes. Since it is proposed to make the use of electronic reporting mandatory, all reporting system operating issues become significant since they can result in non-compliances due to failures beyond the control of the facility. If the proposed electronic system has the benefits claimed in this proposal, it would be quickly and widely used if it were available as an alternative. For these reasons, **API asks that EPA make EPA's Compliance and Emissions Data Reporting Interface (CEDRI) system and Electronic Reporting Tool (ERT) allowed alternatives to submitting hardcopy or PDF reports, at least for several years, until all of the operability and integration issues can be resolved.**

We are particularly concerned about the following specifics of this proposal:

- The failure of this proposal to meet the legal and administrative requirements for 1) imposing a certification requirement on part 60 reports where such a requirement is not currently imposed, 2) imposing new requirements on who may certify that are not imposed by the part 60 subpart that contains the certification requirement, and 3) requiring registration of Preparers and Certifiers, when that is not required for written reports or by regulatory language.
- The plan to impose future compliance requirements through Internet announcements rather than Federal Register rulemaking or at least Federal Register notices. As exemplified by this proposal, adding electronic reporting requirements with compliance deadlines and, potentially, other new report content requirements requires notice and comment rulemaking. API believes the Administrative Procedures Act (APA) and the Clean Air Act (CAA) require that a Federal Register notice and the ability to comment be provided for 1) every change to the CEDRI system that imposes a new requirement that is not present in the subpart to which it will apply, including that a particular report must be submitted electronically after a certain date, and 2) for changes that impose new report content or administrative requirements (e.g., requiring report certification, requiring emission estimates) that are not already required by the underlying part 60

subpart. Federal Register notices would not be required if electronic reporting were established as an alternative to the existing reporting requirements.

- The failure to address the issues associated with part 60 subparts that are referenced from other regulations, Consent Decrees and permits. It is common for part 60 subparts or paragraphs from part 60 subparts to be made applicable by reference, but often with changes. Electronic reporting templates for a subpart should deal with all requirements imposed by that subpart including requirements it imposes through reference and electronic reporting; and use of those templates should not be required until the template for the directly applicable subpart is complete.
- The proposal to require electronic reporting for incomplete pieces of reports. This approach adds large burdens with no benefits for anyone. For instance, requiring electronic submission of performance test velocity measurements when the associated pollutant concentration and calculation method is not covered by the ERT or requiring one data set of many that must be included in a particular periodic report.
- The failure to provide a system to deal with future changes to part 60 subparts. The Compliance and Emissions Data Reporting Interface (CEDRI) and the Electronic Reporting Tool (ERT) templates must immediately incorporate any additional or changed subpart reporting requirements and delete any removed reporting requirements when a part 60 subpart is amended <u>or</u> the CEDRI and ERT templates must accept reports that contain any newly required additional information and omit any information that is no longer required.
- The failure to provide backup reporting provisions for instances in which the EPA system cannot be accessed or when it cannot or will not accept reports electronically on their due date.
- The failure 1) to provide adequate compliance time, 2) to provide for beta testing and user input of each template prior to requiring its use, and 3) to provide tools, such as a "sandbox," to allow facilities to test their new or revised electronic data entry system off-line.

EPA claims on page 15115 of the proposal preamble that "this action does not impose any new information collection burden under the [Paperwork Reduction Act]" and claims on page 15116 that "electronic reporting would reduce costs associated with information collection and, thus, compliance costs in the long-term." Both claims are false.

The proposal actually imposes significant additional recordkeeping and reporting burdens that, in some cases, have not been legally justified and certainly are not cost justified. The proposal will also require additional reports in almost every case, at least for the foreseeable future. It is also important to note that, despite the claims in the proposal, no burden reduction credits under the PRA are available for instituting electronic recordkeeping or reporting, since EPA claimed those credits in its 1999 burden reduction rulemaking[1]. The fact, that electronic reporting is only now being instituted does not allow those burden reductions to be claimed again.

Significant additional information collection burdens will result from the following:

- The proposal will undo the many reporting efficiencies currently in place (e.g., combined reports and delegated reports) and thereby will greatly increase the number of individual reports that must be submitted by facilities. Every additional report carries a burden cost, even if it only contains information that was previous reported as part of another report.
- The proposal will not eliminate any written reports in the foreseeable future because the proposed systems only cover some of the information that is required in most reports, and, thus, the electronic reports will have to be supplemented by written or PDF submissions. As a result, this proposal will cause, at a minimum, two reports to be submitted where one has sufficed.
- Many additional reports (e.g., perhaps hundreds or thousands of additional reports under subpart OOOO) will be required where multiple CEDRI templates are provided for separate portions of a current report or where current reports must be subdivided because of the CEDRI requirement to report site by site.
- Given the differences between the EPA system and existing State systems and the piecemeal and incomplete condition that the EPA system will be in for many years, there is no valid basis for the assumption that a significant portion of States will be using the EPA system within three years. All burdens associated with electronic reporting and with additional reports that result from this proposal are new and additional, as are the substantial burdens associated with separating electronic submission information from current reports and reconfiguring the current written reports to only include the information not covered by the electronic system templates.

[1] See 64 Fed. Reg. 7458 (February 12, 1999)) where, among other steps electronic recordkeeping and reporting was specifically authorized.

- Because previous reports apparently cannot be simply updated for a current submittal under CEDRI, as is the current practice, many additional hours of burden will be incurred generating each electronic report than is currently required. Even if new systems are put in place by industry to automate data entry, the burdens associated with the development and upkeep of these systems are not reflected in the record. Experience with EPA's ERT system demonstrates unequivocally that use of an EPA electronic system is an additional step, performed after reports are independently developed.
- This proposal appears to eliminate currently allowed electronic recordkeeping unless electronic reporting is in use. Such a change will undo the 1999 burden reduction rulemaking and would impose infeasible and unimaginable burdens. No provision for adding back some of the 780,000 hours of burden reduced under the 1999 amendments for allowing electronic recordkeeping and reporting is included in the economic or burden estimates for this proposal. Nor are the additional burdens, costs and impacts of requiring paper records considered.
- The proposal does not account for the burdens associated with users maintaining computer expertise, knowledge of the CEDRI and ERT systems, and updating of facility reporting systems as the CEDRI and ERT systems are revised. It is notable that even the relatively mature and limited ERT system underwent six revisions within the last year, that this proposal and the CEDRI and ERT webpages contain computer jargon and information that is only understandable by specialists, and that it takes an 80 page manual to explain how to access and use the CEDRI system, in general.

API believes this proposal will significantly increase industry recordkeeping and reporting burdens and that EPA should take significant steps to minimize those impacts, including making electronic reporting an alternative until all of the bugs are worked out for each individual subpart and CEDRI template

Please contact me if you have any questions or if we can amplify on any of these comments. I can be reached at (202) 682-8319.

Sincerely,

/s/

Matthew Todd
API

Attachment

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Comments on
EPA's "Electronic Reporting and Recordkeeping Requirements for New Source Performance Standards: Proposed Rule"
80 Fed. Reg. 15100 (March 20, 2015)

Docket: EPA-HQ-OAR-2009–0174

June 18, 2015

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I. Introduction

The U.S. Environmental Protection Agency (EPA) is proposing to revise the part 60 General Provisions (part 60 subpart A) and many individual part 60 subparts to require specified air emissions data reports (typically performance test reports and reports associated with continuous monitors) to be submitted electronically and to allow affected facilities to maintain electronic records of the data associated with these reports.

API members have operations ranging from very small, unmanned facilities, potentially subject to one or two part 60 subparts covered by this proposal (e.g., subparts JJJJ and OOOO) to very large refinery and petrochemical facilities that may be subject to a great many part 60 subparts covered by this proposal. In both types of facilities, overlaps among these subparts and with part 61 and 63 subparts and permit and Consent Decree conditions are prevalent and compound the difficulties of efficiently complying with the proposed part 60-specific requirements.

The proposed changes will result in overly burdensome requirements for these facilities, albeit for somewhat different reasons between small and large ones. API believes the current proposal has serious flaws and legal deficiencies that need to be addressed including 1) providing adequate time for efficient conversion to the new systems and for corrections to EPA's Compliance and Emissions Data Reporting Interface (CEDRI) or Electronic Reporting Tool (ERT) programs, 2) making the conversion efficient and effective by adjusting the electronic system and its implementation in several significant ways, 3) meeting legal and process requirements for imposing new part 60 requirements, and 4) providing clarity for both the regulated community and regulators. To that end, we recommend that electronic reporting be established as an alternative for an extended initial period and that each new CEDRI template be available as an alternative for an extended period until all issues with it are resolved. Beta testing and provisions for a test "sand box" would ease this process significantly. In a few cases, API recommends deferring finalizing some of the suggested revisions until inconsistencies between current rule requirements and the electronic system requirements or wasteful burden impacts due to incomplete electronic systems can be resolved.

The proposal indicates that legally required notice for future changes to the electronic reporting requirements (i.e., adding CEDRI templates) will not be provided. We believe that future changes must, at a minimum, be noticed through the Federal Register and that more substantive changes, including those that result in additional or revised certification requirements, require notice and comment rulemaking.

API also has requested, below, that the proposed regulatory language be addressed, to clarify where the new requirements do not apply (as outlined in the preamble) and to clarify that these requirements are not retroactive.

Finally, the proposal suggests that electronic records, as opposed to written records, are only allowed by part 60 if they are associated with electronic reports through the new EPA systems. That presumption is patently false since 1) EPA specifically allowed electronic records and reports under part 60 in a 1999 rulemaking, 2) most records are already maintained electronically, and 3) the implications of returning to written records have not been addressed. We, therefore, recommend in Comment XI that the discussion of electronic records be clarified in the preamble to the final revisions and that none of the proposed regulatory language dealing with electronic records be finalized.

For convenience, our specific proposals are indicated by underlining.

II. Electronic Submission Should be An Alternative to Hardcopy or PDF Submission of Compliance Reports until all the Operability and Coordination Issues with Electronic Reporting Are Resolved.

This proposal suffers from a failure to address the realities of reporting using an inflexible and difficult to revise electronic system, the realities of the structure of EPA regulations and their practice of referencing part 60 paragraphs and subparts, and integrating EPA's electronic reporting system into EPA, State and company reporting processes. Since it is proposed to make the use of electronic reporting mandatory, all reporting system operating issues become significant since they can result in non-compliances due to failures beyond the control of the facility. Thus, <u>API asks that EPA make the CEDRI and ERT systems allowed alternatives to submitting hardcopy or PDF reports, at least until the operability and integration issues discussed in these comments and the comments of others can be resolved.</u> <u>Similarly, API requests that all new templates be available as alternatives until they are thoroughly tested and user concerns are addressed.</u> Such an approach would allow thorough testing of the systems and templates by actual users and provide time for EPA to address the issues identified. Given the large number of subparts and reports covered by these new requirements and the vast differences between facilities, we do not believe that either we or EPA can prospectively identify the problems that will be discovered in actual practice.

III. No Legal Basis is Provided for the New Requirement that All Part 60 Reports be Certified or For Limiting Who May Certify.

Performance test reports and many other reports covered by this proposal do not have certification requirements in either part 60 subpart A[2] or the applicable subpart. However, this proposal indicates on page 15105 of the preamble and on the CEDRI webpage that the CEDRI system requires a preparer and a certifier and proposes to limit who may certify a report where a certification is required. For instance, CEDRI specifies that the certifier must be the "owner or operator" and cannot be a contractor. <u>EPA must clarify and revise the CEDRI templates and instructions to only require a certifier where a subpart so requires and cannot put conditions on who can certify a submission beyond those in the applicable subpart.</u>

The proposal preamble and the CEDRI webpage state that a certifier is needed to "sign a package using an electronic signature[3]" and that the signature is compliant with the requirements of the Cross-Media Electronic Reporting Rule (CROMERR) "for assuring that the electronic signature is legally associated with an electronic document for the purpose of expressing the same meaning and intention as would a handwritten signature if affixed to an equivalent paper document[4]". It should be noted that the CROMERR only specifies how electronic signatures are validated but does not impose any signature requirement itself. However, the CEDRI system requires a certifier (i.e., electronic signature) even if the subpart requiring the report does not require one. Furthermore, where a certification is required by the part 60 subpart, the CEDRI requirements are different from those in the subpart. In particular, CEDRI goes beyond subpart A signature requirements for excess emission reports, the most common report type addressed in this rulemaking. If a report must be certified or signed by the owner or operator, the subpart requiring the report must impose that requirement after notice and comment rulemaking. Such a requirement cannot be imposed through the CEDRI system protocols.

If EPA intends to require certification for all part 60 reports, this proposal is inadequate to justify this change. The proposal provides no legal authority for this expansive new requirement, does not propose any regulatory language for the affected subparts, does not include the additional burdens in the required PRA analysis or the proposal cost and burden analyses, and only discusses the additional requirement incidentally, as a *fait accompli*, in the preamble and on the CEDRI webpage. <u>To impose a certification requirement where it is not now required in subpart A or in a particular part 60 subpart, EPA must provide a supplemental proposal for comment and obtain approval of the additional paperwork burden under the PRA</u>.

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[2] Subpart A only requires a signature on excess emission reports.
[3] 80 Fed. Reg. 15105 (March 20, 2015), center column
[4] Ibid.

A certification requirement adds burden to each report. Additional burden will also be incurred to maintain certifying official registrations with CEDRI as individuals and responsibilities change. API estimates a certification requirement adds at least two hours to the burdens associated with each report.

IV. Clarification Is Needed on Preparer and Certifier Criterion, Where Certification is Required.

Because of the large number of reports that will require certification (even if the universe of reports requiring certification is not expanded), the limitations imposed by CEDRI on who may certify, and the pace at which responsible officials change, <u>EPA should specifically provide for delegation of certification authority in regulatory language (presumably in subpart A).</u> Furthermore, only larger facilities have individuals present on site who would be considered to represent the owner or operator. In many case, particularly in petroleum industry upstream operations, an owner's representative is likely to be responsible for a great many "facilities" and may not be located at any of them.

Some facility environmental professionals are contract employees and, in some cases, are authorized by facilities to submit reports. There is no valid basis for them not being allowed to be Certifiers, if the owner or operator of a facility duly delegates that responsibility to them. Thus, <u>API requests that the proposed prohibitions on contractors registering as a Certifier or Delegated Certifier be removed.</u>

In some cases, reports are prepared by an owner or operator employee, and there is no reason that person may not both prepare and sign or certify a report. <u>API recommends the definitions not suggest (and that CEDRI not require) that Preparers and Certifiers be separate individuals.</u> Additionally, some reports cover multiple equipment types, and, thus, it may be most efficient for a facility to have different people involved in preparing a particular report. <u>API recommends that the preparer definition not suggest (and the CEDRI system not prohibit) multiple preparers for a single report.</u>

The CEDRI webpage (http://www.epa.gov/ttn/chief/cedri/) describes who may prepare and certify CEDRI reports, and <u>API recommends modified versions of these descriptions be formalized in part 60 subpart A. In addition to clarity improvements, the Certifier description must be revised to only require certification where the subpart requires it and not add constraints beyond those in the applicable subpart (as discussed in the previous comment). Additionally, it should be clarified in these definitions that the preparer and certifier may be the same person.</u> The definitions from the CEDRI webpage, with API's recommended modifications, are as follows:

1. **Preparer:** The Preparer is the person responsible for the preparation of reports for ~~signature and~~ subsequent submission ~~by an authorized representative of the facility~~. ~~Contractors are permitted to register as a Preparer and may assemble submission packages, such as files generated by the ERT, for the Certifier's approval and signature.~~ A Preparer may ~~not~~ sign and submit a submission package if certification is not required or if they are also a certifier or delegated certifier. ~~The Preparer may only access packages which they have prepared.~~

2. **Certifier (Where required):** The Certifier is the duly authorized representative of the source ~~or more commonly referred to as the "owner" or "operator" of the facility~~ as specified in the applicable subpart. ~~The~~A Certifier is authorized to prepare a report package or modify the report package a Preparer has assembled, and sign and submit the package to CDX where a certification signature is required. ~~The Certifier may perform all the tasks the Preparer may perform, but also has submission signing authority. Contractors are prohibited from registering as a Certifier.~~

3. **Delegated Certifier:** ~~The~~A Delegated Certifier is a person granted authority by a registered Certifier to sign and submit packages on behalf of the Certifier. The Delegated Certifier is authorized to prepare a report package or modify the report package a Preparer has assembled, and sign and submit the package to CDX where a certification signature is required. ~~The Delegated Certifier may perform all the tasks the Preparer may perform, but also has submission signing authority. Contractors are prohibited from registering as a Delegated Certifier.~~

V. There is No Legal Basis or Justification for Requiring Preparers and Certifiers to Register.

Signature and certification requirements currently in part 60 (or even for Title V reports, which has the most stringent Certifier requirements) do not require EPA be given a list of allowed Preparers or Certifiers. Anyone can prepare a report today and, since it would be a violation to falsely certify a report where certification is required, appropriate certification is self-policing. No legal or administrative basis is provided in this proposal for requiring an advance listing and no burden and cost estimates are provided. API recommends that the requirement that Preparers and Certifiers pre-register be deleted. Alternately, a supplemental proposal must be provided explaining the legal and administrative basis for this new requirement and allowing for comment.

Given the large number of reports that will require Preparers and Certifiers to register, if the registration requirement is maintained, the extensive change management such a system will require will necessitate a high degree of efficiency in identifying Preparers, Certifiers and Delegated Certifiers. Identifying these individuals on a facility or subpart basis requires multiple entries and makes change management difficult and burdensome. Thus, Preparers and Certifiers should only have to register once and not be limited to particular facility or subpart submissions.

VI. Electronic Reporting for Periodic Reports Must Not be Required for a Subpart or Paragraphs Made Applicable through a Reference from Another Subpart, a Permit or a Consent Decree until the Template for the Applicable Subpart is Final.

Many rules, permits, and Consent Decrees impose part 60 requirements by reference. For instance, part 60 subparts GGG, KKK, and part 63 subpart CC all reference part 60 subpart VV or portions of subpart VV, and many refinery Consent Decrees impose subpart J requirements. However, most such references also modify some of the referenced subpart requirements, resulting in different periodic report content than the referenced subpart itself requires. In some cases, references are to individual paragraphs in a referenced subpart not to the entire subpart. In that case, report requirements can be particularly unclear. Thus, there is a major concern with imposing electronic reporting and the use of CEDRI templates for part 60 subparts whose applicability comes from being referenced from other rules or from consent decrees. A CEDRI template for a subpart that is referenced from other rules, a permit or a Consent Decree will likely be inconsistent with the requirements of the applicable subpart, because it will not reflect the revisions specified in that subpart, permit, or Consent Decree.

In developing the template for a particular subpart, EPA should incorporate any requirements derived from referenced subparts and how they are modified by the referencing subpart. Thus, API recommends that the proposed amendments be modified to only apply electronic reporting requirements where a final template is available for that particular subpart and that electronic reporting not be required for a subpart that was made applicable through a reference from another subpart, a permit or a Consent Decree.

VII. EPA Must Clarify How Referenced Subparts are to Be Handled if Template Applicability is not Limited as Recommended in Comment VI.

As discussed in Comment VI, it does not appear that the CEDRI system can accommodate reports from one subpart that are required by reference from another subpart because of the revisions/modifications to the referenced subpart imposed by the referencing subpart. It is also unclear how CEDRI will confirm compliance with an applicable subpart, if reports use a template for another, referenced subpart. For instance, it is unclear how compliance with part 63 subpart CC is to be demonstrated if one or more of the referenced subparts has imposed electronic reporting requirements and some subpart CC required reports are submitted via templates identified as being for other, referenced subparts. Thus, if our recommendation in Comment VI is not adopted, EPA must make clear how sources are to identify reports for part 60 subparts (and part 61 and 63 subparts in the future) that are filed to comply with referencing subpart, not to comply with the part 60 subpart. Will the templates incorporate a means for providing that information? Will the templates be clear how to handle revised requirements due to changes imposed by referencing subparts?

VIII. At Least Eighteen Months is Required for Initial Compliance When the Current Proposal Is Finalized.

1. Proposed §60.7(c) of subpart A and most of the proposed revisions to specific subparts only allows 90 days from publication of the final rule to start submitting electronic reports where CEDRI templates are already available.

EPA estimates in Table 4 of the preamble, that this proposal will initially impact over 19,000 reports. For the oil and gas industry alone, API believes many thousands of reports per year will ultimately be impacted and thus believes EPA's impact estimate is low. It is impossible in 90 days to get procedures in place, locate or generate needed software, and train personnel for revising such a large number of reports. In addition to the non-trivial effort needed to generate a new electronic report, XML programmers must be hired or reassigned, Preparers and Certifiers must be identified and registered[5], new written reports must be developed for each individual part 60 subpart covering non-CEDRI content, and shared reports must be separated. Finally, permits[6] and procedures must be revised. Significant time and burden will be required

[5] In some cases, as discussed later in these comments, hundreds or thousands of additional registrations will be required because current reports will be have to be divided into a great number of new reports to accommodate the structure of the electronic system.

[6] While many of the proposed changes can be treated as minor modifications and thus use a streamlined permit modification procedure, that is not true for all permit programs or permit conditions. In fact, some permits actually specify that written

to accomplish the necessary revisions and train personnel while not interfering with ongoing recordkeeping and reporting.

There is no legal need to limit the initial electronic report compliance period to 90 days, since the current written reports provide all of the required information and will continue to be submitted until any electronic reporting begins. Thus, given 1) the large number of reports that must be simultaneously revised to fit the CEDRI and Emission Reporting Tool (ERT) frameworks at a very large number of facilities, 2) the required learning curve and training needs, 3) the large population of facilities and personnel that will be dealing with these systems for the first time, and 4) the issues identified elsewhere in this discussion, <u>API believes that at least eighteen months must be provided for initial compliance.</u>

2. Any new system, especially an electronic system, will have errors and/or lack of clarity that does not become apparent until the system is widely used, often in spite of good beta testing. During our recommended eighteen month initial compliance time, the majority of these issues will be identified and the Agency should plan to address them prior to the final compliance date. Other template and system inadequacies will come to light after the compliance period as the full myriad of report variants must be accommodated. Given the inefficiencies of not having a match between CEDRI elements and report content and the potential that CEDRI will not accept reports that do not match the templates, <u>API recommends EPA establish a system for immediately addressing concerns reported by the regulated community.</u>

3. The proposal could be interpreted not to allow use of the CEDRI or ERT systems prior to the 90 day compliance date proposed. In order to foster testing and to allow identification and addressing of problems prior to the compliance date, <u>API also recommends the Agency accept a CEDRI template submittal during the initial compliance period</u>.

IX. Semiannual Federal Register Notices and At Least 180 days are Needed to Allow for Compliance With Templates Added to the CEDRI System.

As described on page 15104 of the proposal preamble, "When CEDRI is updated to support electronic submittal of the required report, you would have 90 days from the date of the reporting form's availability in CEDRI to commence electronic reporting to the EPA." The only notice of the change would be through the CEDRI website, a website most owners and operators do not monitor regularly or should not be expected to look at routinely. <u>Since adding a CEDRI template imposes a new enforceable requirement and a short compliance deadline, the Administrative Procedures Act (APA) as well as the Clean Air Act (CAA) requires official</u>

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reports must be submitted to EPA and those provisions must be changed before a source can replace those reports with electronic reports.

notice of the changes in the Federal Register and notice and comment rulemaking if the change imposes new report content or other new requirements (e.g., certification).

We discuss separately (see Comment X, following) where a full notice and comment rulemaking would be required for CEDRI and ERT changes. Furthermore, the proposed approach would seem to foreclose posting of draft templates for comment and testing, since the proposed language does not specify that the compliance time only applies when final, complete templates are posted. Thus, API recommends that the final rule language be clear that compliance is only required after a "final" template is posted to the CEDRI website.

Even if it has been beta tested, any new form or template will require shakedown and impacted facilities will have to make procedure revisions, undertake permitting activities, identify and register Preparers and Certifiers, and develop or revise computer programming to provide the required data in the required format. If this is the first rule with these requirements for a particular facility, the effort needed will be even more extensive. Experience with the Greenhouse Gas Reporting Rule shows that the proposed 90 days is woefully inadequate. Under that rule, a year was needed to finalize templates. If the part 60 templates are narrowly focused and do not impose changes to the reports already required by an individual subpart, API believes that 180 days, rather than one year, after a Federal Register notice is adequate to comply with such additions. If a template has not been through public review and beta testing, 180 days will be inadequate to identify and resolve template issues and at least eighteen months must be provided.

X. Notice and Comment Rulemaking is Required to Revise a Subpart Where Additional Reports, A New or Revised Report Certification, or Additional Report Content is Required as Part of the Change to Electronic Reporting.

The proposed amendments in this proposal identify specific reports or portions of reports (e.g., excess emission reports, RATA test reports) that are to be submitted through CEDRI (as CEDRI forms become available). For instance, most of the proposed amendments require periodic reports or the excess emission portion of the periodic report to be submitted through CEDRI. If, in the future, EPA desires to 1) have other reports (e.g., one time notices or the full periodic report) submitted, 2) to require report certification where such certification is not currently required by a particular subpart, or 3) to change the content of any required report, notice and comment rulemaking to amend the impacted subpart is required.

Similarly, as discussed in Comment XII, if the CEDRI structure requires information to be submitted piecemeal (see for example Comments XII through XIV below, versus a current periodic report, notice and comment rulemaking must be undertaken to authorize the change and the additional burdens. This proposal imposes many such requirements, but does not appear to have reflected the impacts, costs, and burdens for the additional reporting in the rulemaking record.

Furthermore, any information required by CEDRI (e.g., certain facility information, emission estimates) that is not specified as required content in a particular subpart is not legally required, and <u>failure to submit that information would not be enforceable and cannot be a basis for the CEDRI system declining to accept a submission</u>.

XI. EPA Is Incorrect That Most Records Required by Part 60 Are Currently Kept as Hardcopies, and EPA Should Not Finalize Any of the Proposed New Electronic Record Language.

On page 15107 of the preamble, it is stated: "Most of the NSPS require affected facilities to keep records, such as raw data and reports of emissions monitoring and testing, onsite. Many of the NSPS require that this information be maintained in hardcopy form." On page 15108 of the preamble, it is also claimed "…we believe that electronic recordkeeping is an adequate method of record retention that will improve record accessibility and will provide reduced storage benefits to facilities, resulting in a cost savings for industry. The EPA specifically solicits comment on the proposed amendment to allow electronic recordkeeping in lieu of hardcopy records." Furthermore, in many of the proposed subpart revisions, and especially in the proposed new §60.7(i), it is proposed to add language that specifically allows electronic records for information associated with CEDRI electronic submissions and, by inference, disallows it in all other cases.

The suggestion that written (i.e., hardcopy) records are required by part 60 is false[7]. For example, §60.7(b) of subpart A simply states the owner or operator shall maintain records without specifying in what form. Electronic records are now more common than paper records for all environmental recordkeeping, and part 60 rules do not distinguish how a record is maintained, but only address what records are required and how quickly they must be available. Part 60 currently allows records, including report copies, to be maintained electronically, as long as the data can be provided quickly onsite. Of most direct impact on the

[7] While "written reports" are required in some cases (e.g., for performance tests), "written" records are almost never specified in part 60 (or part 61 or 63).

form of part 60 record requirements is §60.7(f), which deals with monitoring records and is not proposed for revision. It states:

> (f) Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records, except as follows:
>
> (1) This paragraph applies to owners or operators required to install a continuous emissions monitoring system (CEMS) where the CEMS installed is automated, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. An automated CEMS records and reduces the measured data to the form of the pollutant emission standard through the use of a computerized data acquisition system. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (f) of this section, the owner or operator shall retain the most recent consecutive three averaging periods of subhourly measurements and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard.
>
> ...

This paragraph was added to §60.7 through amendment in 1999[8] for the express purpose of allowing electronic recordkeeping and, in concert with the amendments of §§60.7(a) and (c), 60.8(d), 60.13(h), 60.19(b) and 61.04(b) in that same rulemaking, to achieve a claimed 780,000 hours of burden reduction through reduced periodic report frequency, electronic reporting and electronic recordkeeping. The criteria in §60.7(f) purposely does not require written records, since allowing electronic records and reports was the intended purpose of adding the paragraphs. In fact, these requirements are clearly distinguished from those where a written record is required, since, for instance, a "hard copy" of the data acquisition algorithm is specifically required in §60.7(f)(1).

[8] See 64 Fed. Reg. 7458 (February 12, 1999)

Modern monitoring systems generate many data points per second. Neither the amount of paper nor storage space required for hard copies is available. Even if hardcopy storage were available, it would be impossible to retrieve information for a particular time period on a timely basis without searchable electronic databases.

The preamble discussions in the current proposal and the proposed addition of electronic recordkeeping paragraphs to subpart A and many part 60 subparts could be construed, despite §60.7(f), as requiring hardcopy records for any record not associated with a CEDRI submission and could be construed to apply retroactively. EPA has not presented an explanation for reversing its 1999 rulemaking and requiring written records, nor has it identified the impacts on forests, storage space, or burdens. <u>Thus API recommends that none of the proposed language dealing with electronic records associated with electronic reports can be finalized, particularly proposed §60.7(i).</u> Specifically the following proposed paragraphs or paragraph revisions dealing with records associated with electronic report submissions cannot be finalized based on the record provided: §§60.7(i), 60.59a(k), 60.59b(j), 60.76a(g), 60.107(h), 60.115b, 60.276(f), 60.276a(j), 60.287a(d), 60.315(d), 60.455(d), 60.465(d), 60.486(a)(1), 60.486a(a)(1), 60.495(d), 60.545(g), 60.565(o), 60.647(a), 60.697(a), 60.724(d), 60.735(a), 60.747(h), 60.758(g), 60.1385(c), and 60.5420(c).

XII. EPA Must Find Ways to Not Divide Up Current Reports into Multiple CEDRI Reports and Thereby Add Large and Unjustified Burdens.

Many periodic reports, particularly the reports required by some subparts that affect petroleum and natural gas upstream operations (e.g., part 60 subparts IIII, JJJJ and OOOO), allow a single report for many individual affected facility sites. Based on the proposal and the templates currently posted for subpart IIII and JJJJ, it appears the annual report information for these subparts must be separated into separate submissions because CEDRI requires site-by-site reports and individual templates only cover part of the required content for each engine. This separation will impose great inefficiency, since it will cause multiple data entries and certifications. For subpart OOOO, perhaps hundreds or thousands of reports will be required, where one suffices today. These large inefficiencies do not appear to be reflected in the proposal cost and burden analysis and certainly are not justified. <u>API, therefore, recommends that CEDRI templates be exactly matched to current subpart reporting requirements and that any changes to the number of separate reports required because of the structure of CEDRI or the templates be made through notice and comment rulemaking that specifically addresses the requirement for additional reports and certifications. Further, any such change must be reflected in the specific subpart's report content language and PRA approval.</u>

XIII. The Proposed Approach for Subpart OOOO is in Conflict with Subpart Requirements and Should be Revised and Amendment of Subpart OOOO Should Not Be Finalized at This Time.

Part 60 subpart OOOO applies to crude oil and natural gas production, transmission and distribution. It is proposed to require that the annual reports required by this subpart be submitted through CEDRI starting 90 days after a template is available. Because of the unique operations of this industrial category, we see several problems (beyond the cross-cutting ones discussed elsewhere in these comments) with applying CEDRI as proposed, and <u>API requests that these concerns be resolved **before** these new requirements are finalized for subpart OOOO.</u>

1. Under this proposal the subpart OOOO annual report required by §60.5420(b) must be submitted electronically once a template is available. Under subpart OOOO each regulated item is a separate affected facility; however, they are reported together in the annual report. The individual affected facilities are identified in the annual report in different ways (often by their latitude and longitude) but not necessarily by the site where they are located, since there often is no site address and the affected facility (e.g., well) may be the only thing at that location. That is why subpart OOOO does not require that all types of affected facilities be linked with a particular site (e.g., subpart OOOO requires wells and storage tanks be identified by their longitude and latitude).

As we understand it, the CEDRI system links reports to the site at which they are located. Identifying each site separately in CEDRI would require deconstruction of the annual report as currently specified in subpart OOOO (a change which was not proposed), imposing very large unjustified burdens that have not been considered and that are inconsistent with the promulgated reporting requirements of subpart OOOO. For instance, one member company reports they have approximately 8000 such sites and another member reports upwards of 20,000 sites. Although not all of the sites currently require reporting under subpart OOOO, there may be hundreds of thousands of sites in petroleum upstream operations as new wells are drilled and new equipment is added to existing sites. The CEDRI requirement to link every affected facility to a site could therefore require thousands of reports and responsible official certifications for each current subpart OOOO report. <u>API, therefore, requests that the CEDRI system be modified to accept subpart OOOO annual reports as currently specified in §60.5420 of subpart OOOO and not require linking the reports to particular sites and that the proposed amendment of subpart OOOO not be finalized until those revisions are completed.</u>

2. Subpart OOOO requires that the annual report be certified, as does the CEDRI system, however, subpart OOOO has a specific definition of "certifying official[9]" that is different from the definition on the CEDRI webpage (cited in Comment IV above), and API, therefore, requests that the final revision to subpart OOOO clarify that the certifying official for CEDRI reports is the one defined in §60.6430 of subpart OOOO. Furthermore, consistent with Item 1 of this comment, no more certifications can be required then are currently required by subpart OOOO, without notice and comment rulemaking that addresses this specific issue.

XIV. Engine Reporting Requirements Under Subparts IIII and JJJJ Need Improvement, the Small Business Implications of the Subpart JJJJ Performance Test Reporting Requirements Must Be Addressed, and The Proposed Requirement to Use the ERT System Should Not Be Finalized at This Time.

There are three specific issues that need to be addressed.

1. It is proposed to revise subpart JJJJ to require submitting performance test reports through the ERT system. However, that subpart includes specific equations for calculating engine emissions and specifies several alternative test methods for each pollutant, most of which are not covered by the ERT. There is no benefit to requiring electronic submission of extremely partial data and that is clearly all that is possible for engine tests at this time. The only result of this requirement will be to generate electronic submissions that serve no purpose and are never used, since only the written or PDF submission will contain adequate data for evaluating the performance test. For an ERT submission to be useful and for us to be able to evaluate the proposal to require it, all of the method options and the templates for applying the §60.4244

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[9] *Certifying official* means one of the following:
(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:
(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or
(ii) The Administrator is notified of such delegation of authority prior to the exercise of that authority. The Administrator reserves the right to evaluate such delegation;
(2) For a partnership (including but not limited to general partnerships, limited partnerships, and limited liability partnerships) or sole proprietorship: A general partner or the proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;
(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.,* a Regional Administrator of EPA); or
(4) For affected facilities:
(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or
(ii) The designated representative for any other purposes under part 60.

equations must be available. API, therefore, recommends the proposal to amend §60.4245(d) and the applicability of proposed §60.8(j) be deferred until the entire potentially applicable ERT and CEDRI templates are available.

2. Engines subject to subpart IIII and JJJJ change locations and owners frequently. Thus, they cannot be readily identified or tracked by linking them to a particular site as the ERT/CEDRI system seems to require. Thus, the ERT/CEDRI system for engines needs to be modified to identify the engine by only the information specified in subpart JJJJ (i.e., its make, model, engine family, serial number, model year and, by the latitude and longitude of its **location at the time of the performance test**.

Since engines often change locations and owners it would be difficult using a facility based electronic system to assure all required reports for a particular engine have been submitted, since the engine may be at different facilities at different reporting times and thus covered by different annual reports. Inability to match engines to reports would likely lead to difficulties for inspectors in assuring compliance and for owners and operators because of the effort they would have to expend responding to claims that they failed to file reports for engines that they no longer owned or operated. EPA should propose a system that allows tracking of engines by their identifying information, rather than by site. That proposal should also include realistic burden estimates and justifications and provide a simple and efficient mechanism for handling relocation and changes in ownership that does not impose undue burdens on engine owners and operators.

3. There are thousands of engines in petroleum and natural gas upstream operations, and, thus, hundreds to thousands of performance tests per year will ultimately require reporting. Most engine testing is performed by small companies that are not likely to have or to be able to afford the computer expertise needed to report through the ERT/CEDRI system. Thus, this particular portion of the proposal may have a significant deleterious impact on these small businesses. EPA must evaluate the impact of this proposal on these small entities and, if significant, formally evaluate these requirements under the Regulatory Flexibility Act and obtain review by the Small Business Administration.

XV. Prior to Finalizing this Proposal, EPA Must Make the CEDRI System as User Friendly as Possible, Beta Test Individual Subpart Templates, Provide a Test Sandbox and Provide Training for Those Potentially Impacted.

On page 15111 of the proposal preamble, EPA acknowledges that “there is a learning curve associated with the use of our electronic system and data need to be entered initially which will be automatically populated in future reports.” However, EPA is unreasonably optimistic about this learning curve.

Examples of the problems likely to occur with the CEDRI system include the following:

- The XML templates already in the system are not user-friendly, and it is unclear how to populate and use them. For example, some of the environmental professionals responsible for reporting under subpart JJJJ indicate that the CEDRI template is unclear to them and the guidance document only contains two pages that discuss the three currently available templates and provides no real help. <u>One-to-one mapping should be provided for required report content (subpart citation) versus the CEDRI template elements (i.e., spreadsheet cell).</u>

- It is unclear that the CEDRI system templates will comport with subpart requirements. It has been typical in such systems that data not required by individual subparts is requested, and CEDRI apparently will reject reports that do not include this extra information. This concern is exemplified in this proposal, which requires report certifications even where it is not required by a part 60 subpart. Similarly, the CEDRI system requires facility information that may or may not be required by the individual subparts. <u>EPA must not cause facility non-compliances by refusing to accept reports because they do not contain data that is not authorized by regulation and the associated PRA authorization</u>.

- Similarly, it is unlikely that the CEDRI templates will always include all required information or compliance options. Resource limits will make it difficult to include all potential report elements and compliance options in the templates. Yet, CEDRI may not allow facilities to submit reports if all required data elements are not completed in the template.

- Also, the proposed reporting language assumes that the CEDRI template for a particular subpart will include fields for all continuous monitoring and excess emission possibilities. <u>If EPA expects to have multiple templates for different compliance options or to not include all potential compliance options in a subpart's template, the proposed regulatory language should be revised to only require CEDRI reporting for the information that is included in the template.</u>

EPA only has to look at the well-documented issues associated with other electronic data systems to anticipate the massive problems this proposal will generate. It is noteworthy that even after many years the ERT system still cannot be used for all types of performance tests. Feedback from other electronic reporting efforts (like DMR's and greenhouse gas reporting) indicate a beta testing step can identify and resolve many issues prior to initial implementation, thereby reducing the likelihood of non-compliance due to system inadequacies. Similarly, as was found to be highly successful in implementing the greenhouse gas reporting rule, a "sandbox" provision can greatly lessen implementation problems and reduce system-induced non-compliance.

A sandbox is a standalone version of an application not connected to the master database. You can log into the sandbox and try your inputs, make changes to your input system, identify missing data elements in the template, etc. without harming the "real" database. Once there is a complete template and you have a workable input system, you then log on to the real application and enter your data. This would be a good way to test the XML templates and for facilities to test their input systems. A "sandbox" test differs from a "beta test" in that it's available in parallel to the actual application and would not, as beta testing does, only test a preliminary version of a template. This is important, since there are so many potential report variations in part 60 reports, that even a beta test will not test all possible variants.

<u>API therefore, strongly recommends provision of a sandbox and beta testing of all CEDRI templates for the rules covered by this proposal and for all future changes and additions.</u> API members would volunteer to participate in such an effort for the rules that impact our industry.

Because of the complexity of transitioning to this system, <u>API also recommends that, at least for subparts where there are expected to be a great many submitters or where reports are particularly complex, EPA provide training classes and/or webinars on the use of the system prior to implementing each template</u>.

XVI. EPA Must Remove Computer Jargon from the Regulatory Language and Make the Final Regulatory Language Flexible Enough So As Not to Require Amendments as Computer Technology Changes.

Use of computer jargon should be avoided, particularly in regulatory language, to make these systems less off-putting to users and to allow for future changes in computer systems without having to amend the regulations. Unless one is a computer specialist, it is very difficult to follow the proposed requirements or the instructions. For instance, the boilerplate rule language proposed for incorporation into most part 60 subparts in this proposal talks about an "electronic file format consistent with the extensible markup language (XML) schema." Incorporating such computer jargon into regulatory language just adds confusion, since most readers have no idea what it means, and imbedding it in a regulation will require all of those paragraphs which use that language to be amended as computers evolve. This phrase appears 71 times in the proposed rule amendments, which clearly would require a significant and slow rulemaking to revise when the XML computer language is supplanted in the future. API supports providing for electronic uploads of required information, rather than allowing only manual entry, but believes the specifics of that alternative should not be included in the regulatory language. API strongly encourages EPA to remove computer jargon, particularly jargon specific to a particular computer system or language, from the regulatory text when it is finalized and to clearly explain it when it is used in the rule preamble, the CEDRI and ERT web pages and in the system guidance documents. Rather, we recommend that the regulatory language indicate that electronic uploads of required data are allowed using the methodologies specified in the CEDRI and ERT manuals.

XVII. EPA Must Provide Backup Options to Prevent Non-compliances Due to CEDRI Operability Issues

The proposal makes no allowance for the realities of computer systems, computer system complexities, computer system capacity, or computer system vulnerability. This rulemaking must provide for an alternative reporting option for cases where a facility is unable to submit electronically despite a good faith attempt to do so. Specifically, submission of written reports or non-CEDRI electronic reports should be allowed if 1) the CEDRI system is unavailable for more than 4 hours in the three days prior to the submission deadline, 2) if CEDRI will not accept a report in the three days before the submission deadline, or 3) if Preparers or Certifiers cannot be registered within the week before the deadline due to system problems. Alternately, facilities should be given an additional three days after CEDRI becomes available after an outage to submit the report electronically if they prefer that to submitting a written report. Because CEDRI reporting is required for compliance, the Agency has a responsibility to provide a readily usable backup system or to only provide CEDRI as an alternative to written reporting.

Anticipated CEDRI computer issues include:

- CEDRI is unavailable due to technical problems, holiday or maintenance outages, hacking, etc., including transmission facility outages and power outages in the area of the facility. Even a short website or Internet outage can be a problem.
- CEDRI is unavailable (including unreasonably slow responses) because it cannot handle the number of reports being submitted. Typically, reports are filed near the deadline since reporting deadlines are generally just adequate to gather, tabulate, and check the required data. Additionally, many part 60 rules have the same reporting deadlines. Thus, there will be multiple, simultaneous submissions that could slow, delay or overwhelm the CDX system. This has been observed in the past. Similarly, Preparer and Certifier registrations will tend to occur around the submission deadlines, and that portion of the system could be slow or overwhelmed.

- CEDRI is unavailable because of changes in EPA's systems. It is common to find EPA web pages have been moved, renamed, or removed.
- CEDRI reporting options differ from regulatory requirements (too much, too little, different format, doesn't account for a compliance option, etc.) and the CEDRI error checking prevents the submission. This could be due to template development errors, a deliberate decision not to include a little used compliance option in the template, or subpart or general provisions amendments. We discuss the update issues further below.
- CEDRI locks key personnel (i.e., Preparer, Certifier) out of CEDRI (this has happened).

The CEDRI error checking system has been known to improperly prevent report submission. To prevent non-compliances, the error checking system should be revised to provide warnings but not prevent uploads. If leaving an answer blank is appropriate, the system should allow this. If entering text in a box expecting a number is appropriate, the system should allow this. To this end, API also recommends EPA include general comment fields throughout the CEDRI templates that can be used to report required information that doesn't have a specific field or to include explanatory information.

XVIII. EPA Must Address Future Subpart Revisions.

Whenever a part 60 subpart or the part 60 General Provisions are revised, reporting requirements typically change and existing CEDRI templates may no longer provide for a compliant report. In such cases, some data elements may no longer be required and new ones may need to be added. This rulemaking must deal with that situation, since the criterion in the proposal is whether there is a CEDRI template not whether there is a valid template. While a supplemental written report might be used for providing new information, that is inefficient and does not deal with template data that is no longer required. Therefore, API recommends that EPA provide that, upon revision of a part 60 subpart that impacts reporting requirements, written reporting be allowed until the applicable CEDRI template is revised and noticed in the Federal Register.

XIX. CEDRI Must Be Capable of Handling the Many Special Report Situations Prevalent in the Real World or a Written or PDF-upload Alternative Be Provided.

Reports could be refused by CEDRI because the reporting format does not allow reporting in all of the combinations/permutations possibly required. For instance, CEDRI might reject a report when a particular periodic report must include an unusual explanation, such as for a process or monitor outage or out-of-control period, or when a performance test uses a method not supported by the ERT. A simple way to ensure these situations can be handled is to allow a written submission or the upload of a scanned PDF if the required report contains required data elements that CEDRI cannot accept.

Similarly, CEDRI must be able to accommodate reports that differ from the standard format for any of the following reasons, among others.

- A single periodic report provides information covering multiple subparts. For instance, it is common to file a single report covering part 63 and part 60 requirements for a particular set of emission points. Such reports will typically include more data elements than the part 60 subpart requires. Similarly, it is common to file a joint part 60 and Title V report. It is also very common to use one report for several part 60 subparts (For instance, a single report covering part 60 subpart K, Ka and Kb tanks.)
- A report that contains additional information that has been required by the appropriate permitting authority or through a Consent Decree.
- A report containing different information because of an approved alternative monitoring plan or alternative emission limitation or that used a draft or generally allowed modification to a performance test method.
- A report containing different information due to an alternative site-specific monitoring plan as specified or allowed by a particular subpart. For instance, site-specific fuel monitoring plans are allowed by several subparts, including part 60 subpart GG.

XX. CEDRI Needs to Accommodate Efficient Data Entry.

EPA should make efforts to minimize dual reporting, both in CEDRI between different part 60 standards (e.g.: subparts J and Ja) and between CEDRI and written reports (e.g.: subpart J and part 63 subpart UUU, Title V reports, and NSR CD reports). These efficiencies are in place today in many places, and it appears the current CEDRI approach will eliminate the efficiencies of combining reports. The extensive additional burdens associated with this change are not justified or even identified in the proposal or the PRA analysis.

It is also common for considerable information in a part 60 periodic report to be unchanged from report to report. Thus, API requests that CEDRI provide the option to copy data from the previous report rather than having to manually re-enter the data. For example, submitters should not have to manually retype the make, model, and serial number for each CEMS every 6 months.

EPA should also develop templates that recognize that industry may be using one CEMS to comply with multiple rules (e.g.: H_2S CEMS on the fuel gas drum to comply with part 60 subpart J for some heaters and part 60 subpart Ja for others) and set up a feature so the same CEMS data need not be entered twice.

Many refiners are subject to consent decrees that require submission of data that overlaps or includes data required by part 60 subparts. API recommends that EPA specify that data submitted through CEDRI need only be referenced in consent decree reports and does not have to be duplicated.

In some cases, periodic reports may be required to contain significant quantities of data. CEDRI should provide for an efficient way to enter such large blocks of data. A reasonable work around is an allowance to upload PDF files with supplemental data.

Since, as discussed throughout these comments, multiple reports will be required where one has sufficed in the past, there will be a vast expansion in the number of required certifications and the burdens associated with such certifications. To that end, API recommends that EPA develop a system for a combined certification, such that one certification entry can be used for all of the electronic entries associated with a periodic report submission.

XXI. CEDRI Must Provide for Report Updating and Correction

Occasionally reports must be updated or corrected. It is unclear in the proposal how such revisions are accommodated in the CEDRI and ERT systems. API requests EPA clarify this point in the final rule and, if such capability is not currently present, that it be added.

XXII. No Benefits Should Be Claimed for CEDRI Reporting Since Those Burden Reductions Were Already Claimed and There is Little Likelihood that CEDRI Reports will Replace a Significant Volume of Written Reports in the Foreseeable Future.

EPA estimates that CEDRI and ERT reporting will replace approximately 43% of reports to States in about 3 years (See Table 4 of the preamble and the associated discussion), based on an Environmental Council of the States (ECOS) survey that asked states if they intended on integrating EPA's e-Reporting program through the CEDRI into state and local agency programs. API believes it will take much longer than that, probably as long as a decade, for CEDRI and ERT to be able to handle the myriad report variants and data element variants associated with the current part 60 rules completely and to accommodate rule revisions that will occur as reporting moves to the CEDRI platform. Nor, in most cases, does this proposal even envision requiring all periodic report information required by a particular subpart to be submitted electronically. So, even if a State accepts the EPA electronic information, a written or PDF report would still be required to be sent to both the State and EPA in most cases in order to provide the information not included in CEDRI. For instance, for the large number of subparts that require fugitive emission monitoring, only the small portion of the periodic report associated with excess emissions or continuous monitoring must be submitted electronically. Another example is the proposed requirement (via the amendment of §60.107(c)) to submit subpart J periodic reports electronically. In this case, one report content requirement (§60.107(c)(4)(vi)) is excluded from electronic reporting and thus both electronic and written reports will always be required to both EPA and to the State. Thus, even if 43% of States actually begin using CEDRI information for some reports by year three, it will be for a very small percentage of part 60 reports, since complete and fully functional templates must be developed for each subpart and each report type. Even the ERT system which has now been in place and under development for some time, still cannot handle all EPA Methods, and, thus, many performance test reports must still be reported by other means or only be partially reported using the ERT.

API believes it will take significantly longer than three years for States to rely on CEDRI and ERT in place of their own reporting systems to any measurable extent. In fact, many States already have electronic reporting systems of their own in place and are highly unlikely to abandon those in favor of CEDRI.

Furthermore, in 1999, EPA finalized amendments[10] to the part 60 and 61 General Provisions (specifically §§60.7(a), 60.19(b), 61.04(b)) to allow electronic recordkeeping and reporting (along with other changes) and, in that proposal,[11] (which they reaffirmed in the final rule preamble) EPA claimed 780,000 hours of burden reduction for reducing report frequency and allowing electronic reporting and recordkeeping.

Thus, API believes that all of the burdens associated with reporting through CEDRI are additional to current burdens and that there will be no savings starting in year 3 as EPA claims. In fact, burdens will increase due to the use of CEDRI, as discussed elsewhere in these comments.

XXIII. The Burdens Associated with Requiring The Use of a Specialized Electronic System Should be Reflected in the Cost and Burden Analyses.

In addition to not recognizing the costs and burdens associated with losing the current efficiencies of combined compliance reporting, this proposal does not account for the burdens associated with users maintaining computer expertise and knowledge of the CEDRI and ERT systems as they change. It is notable that even the relatively mature and limited ERT system

[10] See Ibid.
[11] See 61 Fed. Reg. 47840 (September 11, 1996)

underwent six revisions in the last year[12]. Sources and testing companies will have to put in place specialized resources to follow such program revisions and modify their data entry to accommodate the changes. Furthermore, one needs only to read this notice and the ERT webpage to understand that computer expertise is required to even understand the system instructions. While that burden may have been manageable for the relatively few subparts and reports where the ERT is currently required (i.e., performance test reports) and for larger testing contractors, with in-house computer expertise, it is unclear that it will be manageable for the multitude of small testing companies to which this requirement is applied by this proposal (see Comment XIV.)

Similarly, EPA has posted[13] an 80 page manual to explain how to access and use the CEDRI system. The details explained in that manual demonstrate the inflexibility of the system, the massive amount of effort that will be required to register and maintain facility and user information, and the inefficiencies associated with having to enter information on forms and through pulldown and other types of menus.

XXIV. Comments on Delegated Reports.

Under this proposal, EPA rescinds any current approval under part 60 for reporting only to the delegated authority once a report can be filed through CEDRI or ERT. While we do not have an estimate of how common such delegation is, removing it increases burdens, since two reports will now be required where one suffices today. It is our experience with the ERT system, where electronic reporting has been required for several years under some regulations, that the electronic report is generated from the written report, and we expect the same to be true for CEDRI reports, thus there is no reporting efficiency. Sites have developed sophisticated systems for gathering data for reporting, and CEDRI data entry will be an add-on to those systems and <u>not</u> be a replacement.

XXV. Comments on Use of ERT for Reporting Performance Tests

1. The preamble claim that this proposal will reduce performance test recordkeeping and reporting burdens is false since 1) the ERT system cannot handle all potentially required test methods and is unlikely to ever do so as test methods are added and modified, thus requiring both electronic and written reporting in most cases, 2) many test methods are modified by individual part 60 subparts and it is unclear the ERT will ever be able to handle those modifications, 3) States and Title V still require written or PDF records and reports, 4) formal reports (paper or PDF) are needed as a deliverable to demonstrate the testing contract has

[12] See the ERT update history available through http://www.epa.gov/ttn/chief/ert/index.html#template.
[13] See http://www.epa.gov/ttn/chief/ert/cedriguide.pdf

been completed, and 5) because experience demonstrates that such data entry cannot be done without first generating a full performance test report.

2. Under this proposal, electronic reporting will be required if a test method is supported by the ERT. However, most performance tests involve the use of several EPA test methods (e.g., one for stack flow, one for stack moisture, one for stack oxygen, and one for each pollutant of interest). However, under the proposal language electronic submission would be required for any performance test where any one of the methods used is supported by the ERT (e.g., if stack flow is determined by one of the Method 2 alternatives), even if the pollutant concentration methodology is not supported by the ERT. There does not seem to be any justification for requiring electronic submission and the associated additional burdens, unless all of the methods used to determine a pollutant's emissions are determined using ERT-supported methods. There is no value, for instance, in submitting a stack flow electronically and the pollutant concentration and mass flow calculation by written or PDF means, since the electronic information cannot be used on its own. Thus, <u>API recommends that the proposal language be revised to only require electronic submission where pollutant emissions were determined using only ERT-supported method.</u>

3. Additionally, EPA has not developed or articulated a reasonable approach to using information that is uploaded through the ERT. The claimed benefits in Section III of the preamble are improved emission factor development and better information for rulemaking. However, no system has been identified or put in place to provide any quality control on ERT performance test submissions. Nor is there any system for relating reported performance test emissions with operating information, design information, control systems, etc. Nor is there a system identified for integrating electronic and non-electronic information as discussed in the previous sub-item. Thus, there are few situations where ERT submissions can be used for developing high quality or useful emission factors. Relative to using this information for rulemaking, the same factors prevent using raw results. For rulemaking, the available emission data has to be categorized against operating, design and control information. Furthermore, performance test data only represents operation at maximum conditions (as required by regulation) and, thus, does not provide information on other operating points or variability. As a result, performance test data is not often used for rulemaking. It is sometimes used to identify pollutants of concern, but that information generally requires use of specialized test methods that are not used in the normal performance tests covered by the ERT. Thus, the information gathered through the ERT is unlikely to be adequate for sound rulemaking and information collection efforts for rulemaking will likely continue unabated with no overall reductions in time or effort required.

XXVI. Applicability Dates Must Be Included in the Proposed New Language.

Since some CEDRI and ERT capabilities currently exist, the proposed requirements to use these tools would appear to be applicable retroactively for most subparts. Part 60 requirements may only be made applicable from the date of their proposal. Thus, in every instance (including in subpart A) where a part 60 subpart does not already contain either or both of these requirements, <u>a phrase must be added to clarify that the electronic submission requirement does not apply to reports covering time periods prior to the date when the electronic reporting requirements are finalized.</u>

XXVII. The Applicability of the Revisions Must be Clarified in the Final Amendments.

Table 1 of the proposal preamble lists part 60 subparts to which this proposal does not apply. However, nothing in the proposed regulatory language excludes those subparts, particularly the proposed amendments to subpart A, which are generally applicable to all part 60 subparts, including those listed in Table 1. For instance, proposed §60.7 requires all part 60 excess emission reports to be submitted via the CEDRI system and proposed §60.8 requires all part 60 performance test reports be submitted using the ERT. Similarly, electronic reporting requirements are made applicable to all part 60 subparts by the proposed amendments to §§60.13, and 60.19. Thus, it seems, without modification, the proposed language will make electronic reporting a requirement for the subparts in Table 1 that EPA states in the preamble will not be subject.

<u>API requests that EPA exclude the part 60 subparts listed in Table 1 of the proposal preamble from the CEDRI and ERT requirements by revising the proposed regulatory language in Subpart A, when these amendments are finalized.</u>

XXVIII. EPA Should Focus on Making the ERT and CEDRI Systems Effective and Useful and Not Waste Resources Trying to Collect Emission Inventory Information, Which is the Responsibility of the States.

On page 15109 of the proposal preamble, EPA states "In lieu of activity data, collecting long-term emissions data would also provide useful data for inventory and rule development purposes. We are specifically requesting comment on whether and how long term activity or emissions data should be submitted electronically."

Collecting emission inventory data is a State responsibility. API, therefore, recommends EPA work with States to secure emission inventory data and to improve emission inventory systems, where needed. EPA's limited resources need to focus their efforts on making the ERT and CEDRI, current and complete, user friendly, and reliable. As discussed above, this effort is likely to take many years and EPA should not divert resources for information collection that is the responsibility of others and not required by law.

XXIX. Compliance Dates for CEDRI Reporting Are Missing From Two of the Proposed Amendments and Need to Be Added.

Proposed §§60.334(j)(5) and 60.4395 require that all continuous monitoring and excess emission reports required by their subparts (GG and KKKK, respectively) be submitted electronically whether or not a CEDRI template has been made available and the compliance time provided in other places (e.g., 90 days from availability of the template) is absent for these subparts. This should be changed to the standard language used throughout this proposal that only imposes electronic reporting requirements 90 days after an applicable template is available and the other changes we recommend in general are incorporated.

XXX. Other Comments.

1. Proposed §60.4(b) states "Information submitted in paper format must be postmarked no later than the date that the report is required to be submitted to the EPA's CDX electronically." Since the reporting due dates are set in the regulation, not in the CDX system as this sentence seems to suggest, this sentence is unnecessary and confusing and should not be finalized. Instead, we recommend the submittal sentence further in §60.4(b) be modified to clarify how written reports are handled, as follows: "All reports must be submitted or postmarked, as applicable, by the deadline specified in the subpart of interest, regardless of the method by which the report is submitted."

2. Proposed §§60.8 and 60.13 include language dealing with reports that might contain Confidential Business information (CBI). They call for submitting the non-CBI information to the CEDRI system. However, it is unclear the CEDRI system will accept such partial reports. CEDRI must either accept reports containing partial information or have a way for submitters to indicate CBI information is being withheld and that the partial submission is acceptable.

Attachment C

Technical Review of Western Climate Initiative Proposals to Meter Fuel and Control Gas

Technical Review of Western Climate Initiative Proposals to Meter Fuel and Control Gas

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Prepared: February 16, 2010

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Technical Review of WCI Proposals to Meter Fuel and Control Gas

I. Executive Summary

The Western Climate Initiative (WCI) makes the assumption that Operators would be reporting the "most accurate" volumes if the gas was metered as a "fuel" stream and a "control" stream instead of applying theoretical factors and Engineering approaches to estimate these volumes. The reports make this assertion without discussing the technology that would be deployed to measure these streams to "provide the rigor required for either cap-and-trade or offset programs". The review below categorically rejects their basic assumption and asserts that the act of installing meters on the streams considered will provide a **false sense of security** and a **net deterioration in the quality of data reported**.

There is no gas measurement technology currently existing that would provide better data in the field than is currently being reported using manufacturer's numbers and theoretical calculations. In addition to making the data less representative of reality, the costs that would be imposed are staggering—industry would be required to spend billions of dollars to report gas emissions data that is demonstrably worse than the data they are reporting today.

A. Summary Expenditures

The "Per Company" column below assumes 2,000 wells per company, "Total WCI" column assumes 100,000 wells affected in the WCI States and Provinces (breakdown is included under "Cost of Implementation" below). Many wells cannot sustain either the increased operating cost or the capital expenditure so they would be plugged instead of spending this money—there is no way to predict this mix of expenditure vs. plugging.

	Per well ($k)	Per Company ($million)	Total WCI ($million)
RTU Replacement	$3.5	$7	$350
Host/Database		$15	$750
Site Modifications	$30.0	$60	$3.000
Total Capital	$33.5	$82	$4,100
Annual Operating Costs	$1.5	$3	$150

B. Author Biography

David Simpson has 30 years experience in Oil & Gas and is currently the Proprietor and Principal Engineer of MuleShoe Engineering. Based in the San Juan Basin of Northern New Mexico, MuleShoe Engineering addresses issues in Coalbed Methane, Low Pressure Operations, Gas Compression, Gas

Measurement, Field Construction, Gas Well Deliquification, and Produced Water Management.

A Professional Engineer with his Master's degree, David has had numerous articles published in professional journals, has contributed a chapter on CBM to the 2nd edition of Gas Well Deliquification, by Dr. James Lea, et al, and has spoken at various conferences, including the 2003 SPE *Annual Technical Conference and Exposition* in Denver. He has been a featured speaker at the bi-annual *Four Corners Oil & Gas* Conference for the last 6 years and is a regular instructor at short courses at the annual ALRDC *Gas Well Deliquification Workshop* in Denver. David was Program Chair for the highly successful SPE Advanced Technology Workshop titled "Managing the Performance of Low Pressure Gas Wells and Associated Facilities" held in Ft Worth, TX in October, 2008. His consulting practice includes clients in 10 countries.

II. Discussion

The Western Climate Initiative has developed at least two documents that each reach the conclusion that gas consumed on wellsites must be measured to achieve adequate "accuracy" in accounting for emissions. The documents further require that gas used for pneumatic controls must be measured separately from gas burned because vented gas has a different "emissions factor" on the environment than burned gas has.

The industry has long said and demonstrated that measuring either fuel gas or control gas represents a very large cost for a very small return. The discussion below supports that position.

A. Magnitude of Gas Consumed

1. *Engine Fuel*

The industry has an excellent understanding of engine fuel. Where engine fuel is measured, the theoretical correlations match very well with measured data. The added value of measuring this fuel-gas stream is not clear to most wellhead compressor operators; consequently it is rare to see a fuel meter on a wellhead compressor or pump jack. The various stakeholders in the gas production process (including regulatory agencies and mineral owners) have accepted that these volumes are both small and adequately represented by the theoretical usage factors.

Engines utilized in field locations range from a single-cylinder Arrow running a pump jack (smallest is the Arrow C-46 which is rated at 6 hp at 500 rpm at sea level with 70,000 BTU/hp-hr fuel consumption) to a nominal 1,000 hp compressor (such as the Waukesha P48 GLD which is rated at 1,200 hp at 1,400 rpm at sea level with 7,720 BTU/hp-hr fuel consumption). This equates to a required measurement range of 5 MCF/day to 220 MCF/day (3.5 to 153 SCFM) assuming a pump jack at ½ load and a GLD at full load.

2. *Separator/Tank Heaters*

I recently did a review of 536 tank and separator burners in the San Juan Basin. Burner nameplate capacity ranged from 50,000 BTU/hr to 500,000 BTU/hr. The average capacity was 340,000 BTU/hr. Since these burners only operate 5-6 months out of the year, this number equates to less than 170,000 BTU/hour on an annual basis. For some perspective, the on-demand hot water heater in my house is rated at 185,000 BTU/hour. This is a fair comparison since both devices are classed as "on demand" in that they will each turn off when conditions warrant—while in service, tank heaters only run a fraction of the time to maintain the tank at the set temperature.

The current method of reporting fuel consumed in burners is to determine if the heater had gas to it during the month, if it did then most operators take the nameplate energy consumption times 24 hours per day for every day of the month. For a 340,000 BTU/hour burner this equates to 253 MMBTU in a 31 day month. I have worked with several operators who would report this number even if the burner only had gas to it for a single day.

In reality, the water or condensate entering a tank is usually substantially warmer than the burner set point so the burner will tend to run less than 15 minutes out of an hour on the coldest night. This means that if you shut your heater down at noon on April 1 you would have burned 1 MMBTU for the month and reported 253 MMBTU. Even if the burner has gas to it for an entire month, you burn the gas in the pilot for 744 hours in a 31 day month (typical pilot lights burn approximately 1,700 BTU/hr), but you only run the main burner for something like 186 hours—for a 340,000 BTU/hr burner you consume less than 70 MMBTU and report 253 MMBTU.

The main challenge of measuring the gas consumed in a burner is that the device must measure the pilot flow with the same level of uncertainty as you apply to the main burner flow. For a common 500,000 BTU/hr burner this means that you have to have a 294:1 “turndown ratio”. Turndown ratio is a measure of ability of a measurement device to provide similar “accuracy” over the expected operating range. According to Wikipedia, a Square Edged Orifice meter has a turndown ratio of 3:1. Even a Diaphragm Meter (similar to residential gas meters) only has a turndown ratio on the order of 80:1. A meter that can measure full burner flow would register zero with pilot flow.

With burner on/off control, there is a rapid transient in the flow as the line fills upstream of the burner followed by steady flow. A device that could successfully capture both the transient and the steady flow would have to be able to go from “off “ to the top end of its range in less than 1 second, and then hold steady for up to 15 minutes, then go to zero in a fraction of a second. There is so much uncertainty in this transient flow that any available gas measurement technology would yield a worse result than manufacturer’s estimates and Engineering calculations.

Required measurement range 0.04 to 12 MSCF/day (0.02 to 8.3 SCFM).

3. *Dehydrator Reboilers, Heater/Treaters, and Line Heaters*

These devices are similar in specific energy-use to the tank/separator heaters, but they tend to run continuously.

Dehydrators are used to remove water-vapor from a gas stream. This water vapor is adsorbed to a liquid that must then be regenerated. Regeneration takes place in a reboiler that is used to add enough heat to the liquid to cook the water out (about 8,000 BTU/lbm of water on average). Since “rich” liquid (i.e., liquid containing high levels of water) is continuously entering the reboiler, the heater is always on.

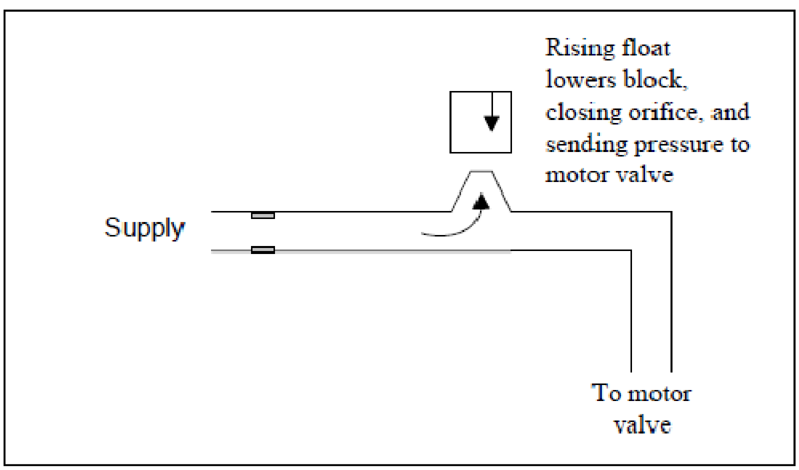
Both Heater/Treaters and Line heaters are designed to add heat to a process stream to control a process variable. For example, Line Heaters are often used in waxy crude to prevent precipitation of paraffin in the pipe causing a clogged line. A Heater/Treater is used to flash light hydrocarbons for further processing into Natural Gas and Natural Gas Liquids streams. Both of these classes of equipment have burners on the high end of the expected range for tank/separator heaters, and both operate around the clock, year-round.

Many technologies could be used to meter any of these streams with adequate repeatability and uncertainty. Whether you meter this stream or use engineering calculations, you will get very similar volumes burned.

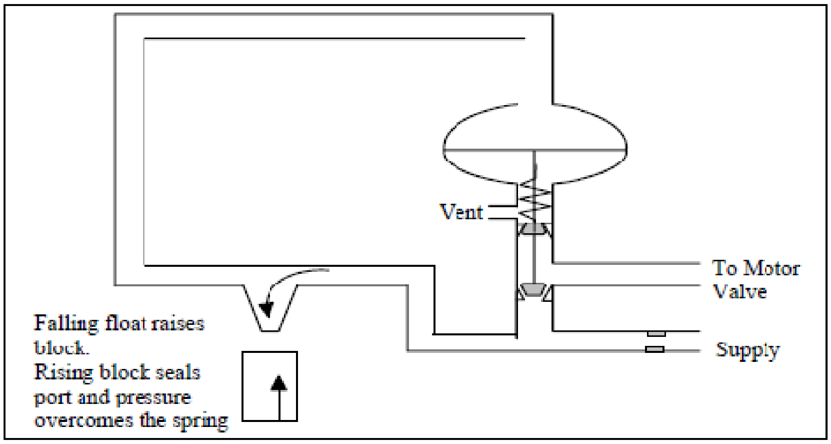
4. *Pneumatic devices*

I did a study in the year 2000 (see SPE 61030) that quantified the gas used in high-bleed pneumatic devices. The project described in that paper was an economic success because we were able to replace high-bleed CEMCO throttling level-controllers with no-bleed, snap acting level controllers. The replacement controllers were markedly less effective, but they were marginally good enough and we were able to sell the gas that would have been vented in the CEMCO.

When talking about controllers (level, temperature, etc.), there are two parameters that have to be clarified: (1) Signal Type and (2) Bleed characteristics. Signal type is either “Throttling” or “Snap Acting”. Bleed characteristic is either “continuous bleed” or “no bleed” An example of a Continuous Bleed, Throttling controller is shown below

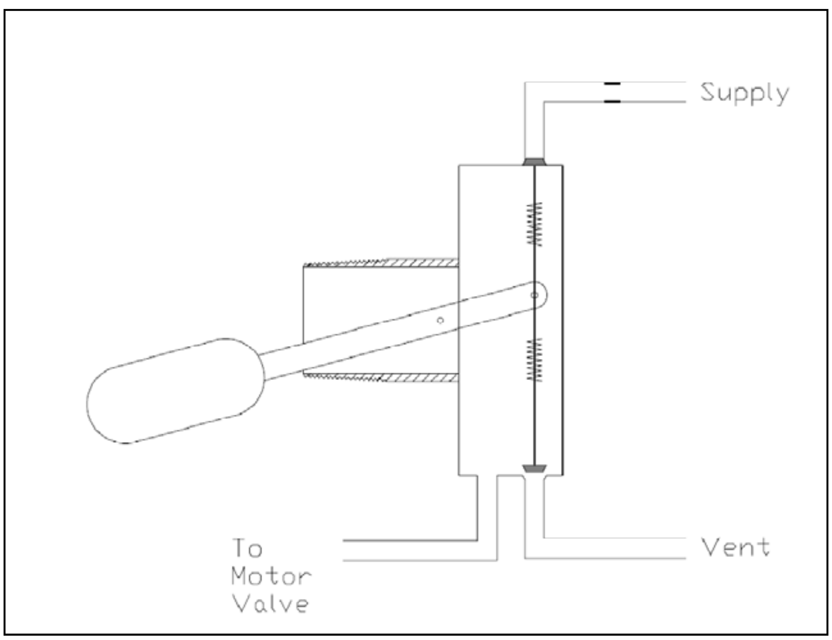


In this device, supply gas is provided through a restrictive orifice to the vent. As the block (attached to a level float for example) descends, it begins restricting the flow through the vent and sends pressure to the controlled device (a motor valve in this case). The beauty of this device is that it operates the controlled device very gently and tends to produce very stable performance. The downside is that you are venting gas anytime that the controlled device is other than fully open. Since many controlled devices are shut most of the time (e.g. in the referenced study, we determined from a sample of over 4,000 wells that the average well cycled the separator dump valve 5 times per hour for 3 minutes each cycle) some operators have tried to reduce the amount of vented gas by turning the process over like:



In this case, the block closes the vent most of the time. When the fluid level increases, the vent opens some. When the vent is opened far enough to drop the pressure on top of the pilot below the spring setting, the pilot snaps open and sends gas to the motor valve very rapidly. At the end of the cycle, the pilot goes shut and vents the motor valve through the top valve seat. Instead of venting for 45 minutes each hour, it vents about 15 minutes per hour at the cost of throttling the flow.

A “No Bleed” controller would look something like:



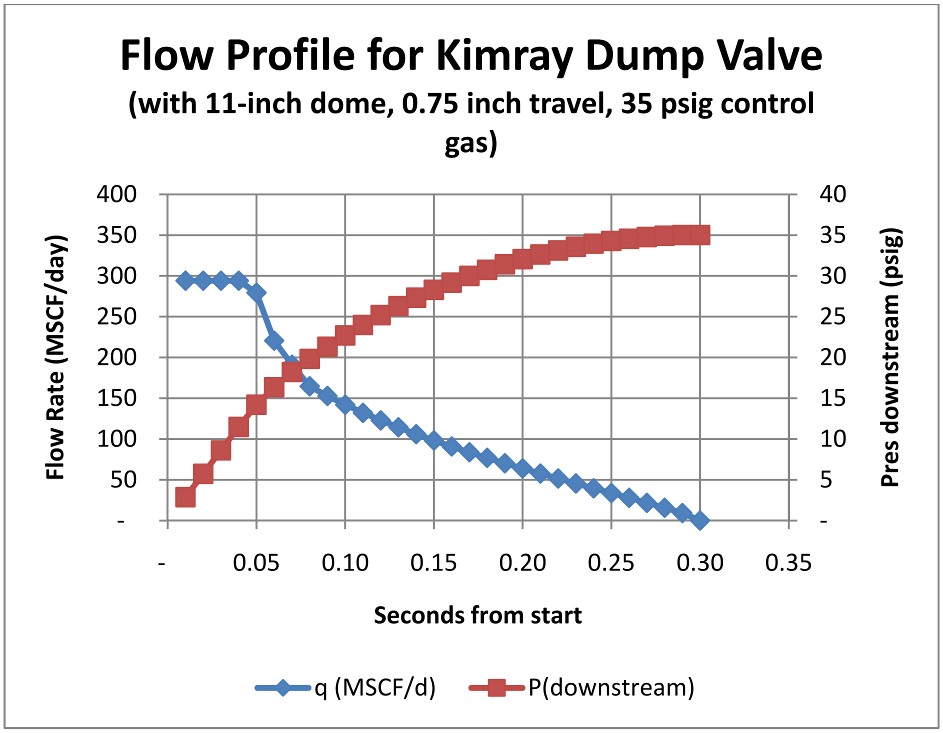
This simplified example shows that when the float is down, the supply valve is shut tight and the vent valve is open. As the float starts rising, the vent is closed. As it continues to rise it reaches a point where the spring tension is inadequate to hold the supply valve shut and it "snaps" open. At the end of the cycle the falling float reaches the point where it can close the supply. As it continues to fall it eventually reaches the point where the vent opens and the motor valve shuts. Most snap acting controllers are applied in service this simple and it is rare to require a pilot in this on/off service.

Notice in the description of the action of the no-bleed controller, the supply gas us used to operate the valve against a dead-end. At the end of the process the supply is shut off before the vent opens. The only gas that is vented in a no-bleed controller is the volume of the piping and the motor-valve bonnet. The supply system is never directly exposed to an open vent, so there is no ongoing "bleeding" of gas.

It is possible to throttle a controlled device with a no-bleed controller with an external pilot, but the control tends to be poor and can't be controlled very long (i.e., the devices used to sense an intermediate position are cumbersome and tend to have a "jerky" action). For practical purposes, when you decide to go to no-bleed you are locking the device into snap acting.

Continuous-bleed controllers are reasonably easy to meter the gas (a CEMCO continuous bleed, throttling level controller vents about 800 SCF/day at 35 psig supply pressure assuming that it is not venting or is venting at a reduced rate for 15 minutes per hour).

For a no-bleed controller, each time the dump valve cycles, control pressure is applied to a diaphragm to counteract spring tension and open the dump valve. At the end of the cycle, the line from the controller to the diaphragm and the diaphragm dome are vented to atmosphere. If we assume that the two devices are connected by 12 ft of 3/8 tubing (0.0092 ft^3) and the diaphragm dome is 0.04 ft^3 (assuming 11-inch diameter, and 0.75 inches of travel) then the volume vented each dump is 0.049 ft^3. At 35 psig and 60°F then this volume is 0.157 SCF/dump. At 5 dumps per hour this equates to 19 SCF/day (2% of a high-bleed device). The flow and pressure profile will look like:



Notice that the entire cycle takes something on the order of 0.3 seconds. This flow is made up of a period of sonic velocity (Reynolds Number 996,000) followed by a period of a significant fraction of sonic velocity (Reynolds Number ends up at 648,000 for 0.65 Mach), and finally a period of flow in a normal turbulent flow regime ending with a Reynolds Number of 10,000 just before the level control is closed. A measurement device would have to be able to go from offline to 294 MSCF/d within 5 ms, and be able to do a 100:1 turndown ratio. No meter ever made has that kind of latency or turndown ratio. Some meter technologies would give you numbers (most would never register), but none will give you measurement.

B. Gas Measurement Technologies

When I talked about "meter accuracy" above I always said "accuracy". "Accuracy" is an amazingly imprecise term that is never used by competent gas measurement professionals. The layman/advertising concept of "accuracy" is encompassed in the terms "repeatability" and "uncertainty" which have precise definitions that can be measured and used to compare the performance of a device relative to a standard or to another device.

"Repeatability" is a measure of a device's ability to report the same output for a given set of inputs. Many things can impact a device's repeatability. For example, turbine meters have the worst repeatability of all industrial gas measurement devices because gear lash is a random parameter that can change the speed of the turbine rotor by several percentage points independent of the magnitude of the change in measured input parameters. Acceptable repeatability occurs when the standard deviation of the sample data is within ±0.05% of the mean value.

"Uncertainty" is the "dead band" of the instruments. Each component of a gas-measurement station has a defined uncertainty, usually expressed in a range around the device's calibrated span. For example, a digital pressure transducer may have a stated uncertainty of ±0.5% which means that if the device has a calibrated span of 0-10,000 psig and reads 450 psig then the reading represents a value between 400 and 500 psig. Recalibrating the same device to 0-500 psig would change the meaning of 450 psig to 447.5-452.5 psig. Uncertainty is just that—you do not know where the actual number resides within the uncertainty range. A gas-measurement device is generally considered acceptable if the cumulative effect of each end-devices' uncertainty is less than ±2.0% (this is based on government requirements which were set before digital instruments, about 1% of the total uncertainty is uncertainty in manual chart integration, 0.5% is from using average temperatures). Electronic Flow Measurement (EFM) devices and digital temperature/pressure instruments make normal uncertainty less than 0.5% in most square-edged orifice (AGA 3) stations today.

Another important gas-measurement concept is "latency". Latency is a measure of the time lag between a change in flow and that change being reliably represented in the measurement device output. Every technology has some amount of latency. For example, a stopped turbine meter requires flow to overcome static friction before it starts spinning, and once it starts spinning it will tend to spool up to a high angular velocity before coming back down to report the actual flow rate. Consequently, turbine meters perform best in very steady flows—putting a turbine on the gas line to a separator dump valve would result in the meter not registering most dump events and over ranging on the few that it does register.

All gas measurement technologies are "inferential" technologies. This means that the equations infer a flow rate from some unrelated, but measurable, parameter. For example, Square Edged Orifice Measurement uses the *Bernoulli Equation* published by Daniel Bernoulli in 1738 to relate the pressure drop across a known flow restriction to a velocity, and then uses specific correlations developed for gas measurement to convert the velocity into a volume flow rate at standard conditions. The first assumption in Mr. Bernoulli's development of his famous equation is that the fluid is both incompressible and inviscid. Neither of these assumptions is literally true in a gas flow, but the industry has proven that both assumptions are close enough to being true to allow meaningful flow rates to be estimated. At commercial velocities, highly compressible natural gas does indeed act like an incompressible fluid unaffected by fluid friction over short distances. As velocity increases toward the speed of sound or decreases to result in a Reynolds Number under 4,000 the incompressible assumption becomes progressively less valid and the uncertainty in a measurement device increases dramatically.

1. *Gas Analysis*

   Many states and the federal government have agreed that small wells (typically wells making less than 100 MCF/day) would be exempt from requirements for semi-annual analysis of the gas. This decision has not caused wholesale inaccuracies and I get the impression that all the stakeholders are satisfied with annual or even less frequent gas analysis.

   For the Western Climate Initiative to re-introduce semi-annual analysis requirements and to propose quarterly analysis on small streams is not a reasonable imposition.

2. *Square Edged Orifice Meters*

   The operating principle is to infer a flow rate from the differential pressure across a known restriction based on measured pressure and temperature. For a clean, well conditioned flow stream the uncertainty of the reported volume is on the order of 0.5-2%. Both uncertainty and repeatability are adversely affected by 2 phase flow, dirt, and changes in flow profile and in small-volume and/or intermittent service the uncertainty can exceed ±25%.

   These meters are the most common type of gas measurement in upstream gas operations. One of the reasons for their popularity is the extensive body of research that has gone into defining the meter configuration and operating limits. This research is documented in the series of reports collected into API 14.3 (also published as AGA 3).

   The standards indicate that Square Edged Orifice measurement is only appropriate in meter tubes equal to or greater than 2.000 inches internal diameter (ID) and for Reynolds Numbers above 4,000. This means that the smallest volume that can be reliably measured with this technology at 35 psig is 5 SCFM (7.2 MSCF/day).

   Latency in this technology is caused by the chaos in the flow as it moves to establish a pseudo-steady-state condition. I have evaluated carefully-controlled flows at the Colorado Engineering Experiment Station (CEESI) during start-up using instruments that record pressures 100 times per second and have found that reaching repeatable flow in a Square Edged Orifice Meter can take as much as 5 minutes from a dead stop.

3. *V-Cone Meters*

   The operating principle is to infer a flow rate from the differential pressure across a known restriction based on measured pressure and temperature. These meters are self-conditioning and tolerant of solids. The total uncertainty is on the order of 0.5-1%. Turndown is 10:1, and it is advertised to work down to Reynolds Numbers of 6,000 or greater.

   This device has potential, but the smallest meter (1/2” ID) would register zero during pilot flow and would have a dP less than 7 inH_2O (0.25 psi) while supplying gas to a 500,000 BTU/hr burner which would increase the uncertainty to several percent.

Latency of these meters is similar to Square Edged Orifice Meters.

4. *Turbine Meters*

   The operating principle is to relate a rotor's angular velocity to a volume flow rate. Turbine meters assume reasonably steady flow with respect to time. Changes in rate take considerable time to steady out. Latency for a change to a flowing stream can be up to a minute, for a start/stop flow it can be many minutes.

   Turbine meters rely on considerable mass to spin the rotors and they rarely provide adequate results in gas flows below 50 psig.

5. *Coriolis Meters*

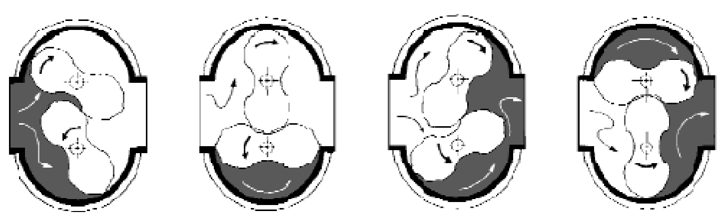
   The operating principle is that the momentum of a flowing fluid will vibrate a piping loop, and that the frequency of the vibration is a function of the mass flow rate and density of the fluid. Low velocities and low pressures have a serious negative impact on uncertainty and repeatability. The MicroMotion division of Emerson has some fairly new instruments that can handle quite low flows, but the latency is similar to a turbine meter.

6. *Ultrasonic Meters*

   The operating principle of Ultrasonic Meters is that there will be a Doppler Shift in the speed of sound as fluid moves away from a fixed sound-pickup point. The magnitude of this shift is a function of fluid density and fluid velocity. Low velocities and low pressures have a serious negative impact on uncertainty and repeatability.

7. *Roots Rotary Meters*

   The operating principle of these positive displacement meters is to trap a fixed volume of gas within each revolution of a pair of lobes. Counting revolutions yields a volume.



   This device is quite close to "measuring" gas volumes instead of "inferring" a volume from a tenuous mathematical relationship, but it is still counting revolutions instead of gas molecules.

   Latency in Rotary Meters is very high due to having to start the rotors spinning again and leakage past the rotors before they start spinning.

8. *Diaphragm Meters*

   The operating principle of these positive displacement meters is to fill a resilient chamber to line pressure, then that chamber is shifted to the demand side while a second chamber is filled. Each time the meter shifts chambers it records a pulse that represents a known volume.

   The uncertainty, repeatability, and latency of these devices is excellent. Turndown ratio is on the order of 80:1. "Household quality" meters would handle the low flows, but materials of construction are generally inappropriate for field gas (e.g., they have considerable brass that is rapidly deteriorated by any H_2S in the flow; all of the Household meters have aluminum casings which have not stood up well to condensate service). "Industrial quality" meters are considerably more expensive and many of them still have inappropriate materials. A meter with no aluminum or "yellow metal" is difficult to find and is very expensive.

9. *Exotic/Laboratory instruments*

   The volume of gas discussed in this application kept leading me to devices like "Thermal Dispersion Meters" (this meter has two probes, one is heated and one is a temperature sensor, the dT can be correlated to a mass flow rate, very long latency); and laboratory quality devices that are absolutely intolerant of free liquids and/or solids. None of these devices has a published standard for construction, installation, and operation and none has a reasonable chance of success.

10. *Conclusion*

    In conclusion, the act of installing meters on the streams considered will provide a false sense of security and a net deterioration in the quality of data reported. Specifically:

    a) Engine fuel can be measured by dP inferential devices (either Square-Edged Orifice Meters or V-Cone meters), but the resulting metered volume will be very close to the theoretical data that is being collected today. Where the two numbers are significantly different I would expect that there is a measurement device error (such as an incorrect meter parameter or a backwards orifice plate) before I would expect the theoretical calculation is incorrect.

    b) No meter exists that can reliably measure both pilot flow and burner flow on a tank or separator heater if the burner is the only load on the system. If measuring these volumes becomes mandatory, then a diaphragm meter could be used to measure the pilot flow and either a Roots Meter or another diaphragm meter could be used for the burner flow. A fuel gas system with multiple engines and multiple burners could be metered with a V-Cone or Square-Edged orifice meter, but the burner volumes would only be able to be measured while the engine was consuming fuel—when the engine is not running, the burner is unlikely to register as an increment from zero.

The theoretical values for burners could be improved by putting a "valve open" clock on the supply line, which (in conjunction with manufacturer's data and Engineering analysis) would result in a better volume than attempting to meter the gas.

c) Heater/Treaters, Dehy Reboilers, and Line heaters are reasonably constant loads that could be metered by several of the technologies above (the diaphragm meter would be preferred, but the small V-cone and the smallest Corriolis meter would work), but again the data would be of a similar magnitude of the data being reported today.

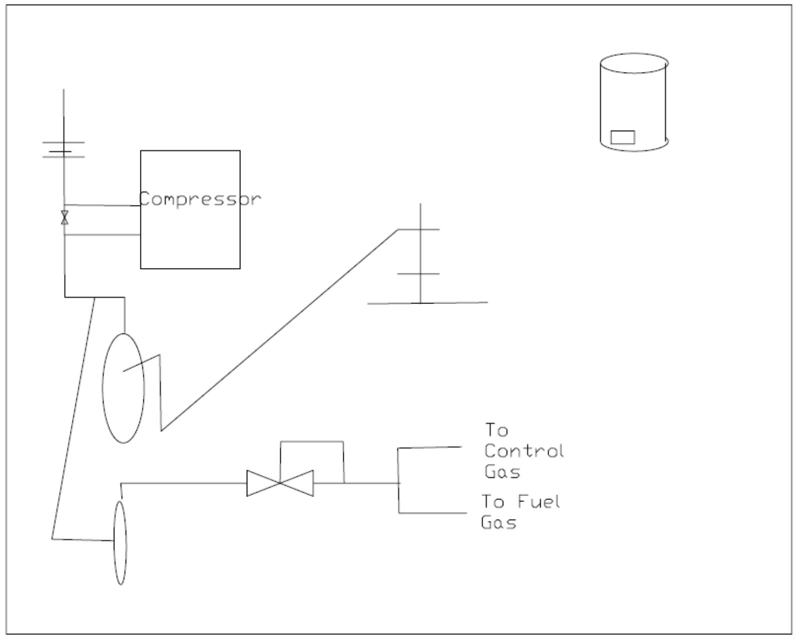
d) No meter exists that can reliably measure the flow to a single dump valve or even a dozen dump valves off the same no-bleed controller. Even if a group of dump valves (three or more) were controlled off the same controller, the flow and pressure traverse would be similar to the one above and the meter would have to go from zero to 900 MCF/d in a few milliseconds then back to zero within about 1/3 second. It can't be done.

   The diaphragm meter comes the closest, but it will tend to either be over ranged for most of the flow period or will fail to register a significant portion of the tail. I would guess that the total uncertainty would be on the order of 20-30%.

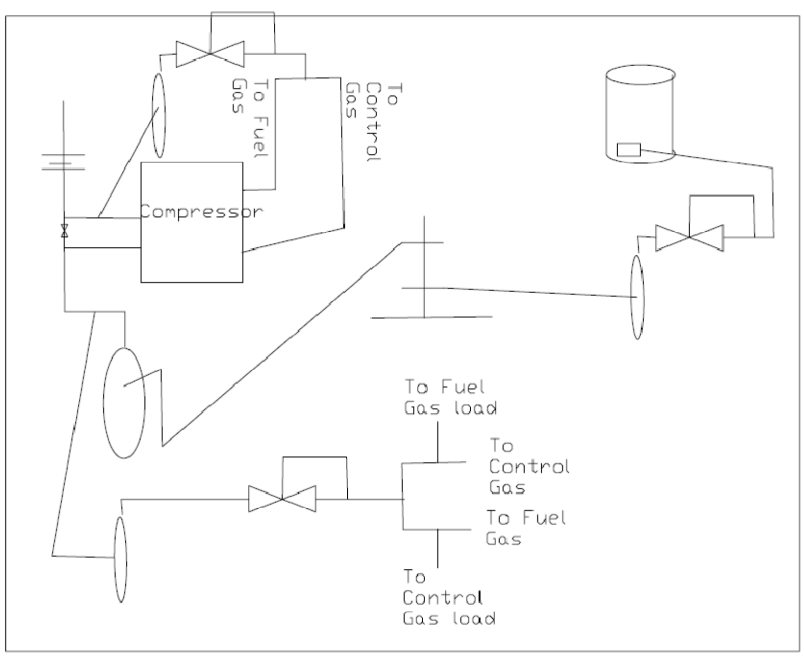
   On the other hand, the flow to a continuous-bleed controller could be measured successfully with either a Roots meter or a diaphragm meter.

C. Wellsite Configurations

The reports from the Western Climate Initiative start with an assumption that there is something that can be reasonably termed a "standard" wellsite where fuel-gas measurement equipment can be "relatively easily" installed. This is patently false. The implication is that every site looks something like:



This layout brings gas from the wellbore tubing to a single separator, and then takes fuel gas off the separator outlet to supply both control requirements and fuel requirements. While there are wells that are configured like this, they are rare. A layout that would be equally as likely to occur would look like:



This layout did not suffer the expense of running a fuel gas line across the location to supply gas to the tank heater from the separator; it pulled that fuel stream from the casing valve and put a second fuel pot as a less expensive alternative to laying a line. Also, the compressor takes its fuel and control gas from an on-skid fuel-gas system. This is the normal configuration since compressor-discharge gas is far better suited to both fuel gas and control gas applications than suction gas is.

This distributed fuel-gas supply scenario has evolved over the decades because the regulations in place at the time of site facilities-construction did not presume to tell operators how to build their sites.

III. Costs of Implementation

It is difficult to develop costs for a "typical" wellsite, "typical" automation system, or "typical" host/database modification because there is no such thing. There are companies within the WCI area of operation that don't have any automation or measurement on their wellsites today and use Excel spreadsheets to allocate sales volumes back to wells. There are companies with home-grown automation systems that have zero flexibility and cannot be retrofit for two additional volume calculations and would have to be discarded and replaced. There are companies with purchased systems that they do not have the license to modify. There are wellsites that will be trivial to retrofit. There are wellsites that will require laying new lines and replacing production equipment.

My approach to cost estimates is to try to address the wellsites, field automation equipment, and host/database systems that I've worked with at my clients operations over the years. I am certain that this technique will be representative of a large number of wellsites and a number of operators, but it will not be all encompassing because it is impossible to assess all of the permutations.

Accessing EIA data at http://www.eia.doe.gov/pub/oil_gas/petrosystem/petrosysog.html and CAPP data at http://www.capp.ca/GetDoc.aspx?DocID=146286 for 2006 (the last year that has both US and Canadian well counts) I get the following counts of wells (after deducting 31,000 wells from California to account for Kern County):

	Gas	Oil	Total
New Mexico	36,202	15,456	51,658
California	3,692	16,197	19,889
Utah	5,259	2,574	7,833
Montana	6,207	4,199	10,406
BC	6,608	1,122	7,730
Manitoba	0	2,692	2,692
			100,208

For the economic analysis I'll use 100,000 wells.

A. RTU costs

Looking at the specifications on a number of RTU's, there are high-end RTU's like the Fisher FloBoss 107/107E that can accept multiple gas-measurement inputs. These devices are not the norm for wellsite use. More common are units like the Kimray DACC 500 RTU that can only accept one flow calculation. At least 75% of the RTU's currently installed will need to be upgraded at a per-unit cost of $4,000-5,000. Assuming that 25% of the locations do not need RTU replacement then the average for the wells is approximately $3,500/site.

B. Host/Database costs

Host databases are very difficult to modify. Changing the Host requires that you: (1) have a place to put the new data; (2) change the data poling logic to pull the new data off the RTU to populate the new database fields; (3) add the new data to EFM editing programs; and (4) modify reporting systems to show the new data. I spent 12 years managing projects similar to this for Amoco and was involved when Amoco was making some significant changes to their host database. Amoco's changes were far less extensive than adding two measurement points that have to be reported to regulatory agencies and those changes cost $15 million and took almost 2 years. If the average impacted user has 2,000 wells then for 100,000 wells in WCI you could expect to spend $750 million.

C. Installation costs

After interviewing several operators and several roust-about service providers, modifying control and fuel gas systems to allow measurement and installing measurement equipment should be budgeted at 10 days of work per site. At $1,200/day that is $12,000/well labor. Jobs like this one are typically 60% materials (including the cost of a meter run of undecided technology) and 40% labor so total budgetary cost should be $30,000/well—100,000 wells would cost $3 billion.

This does not address the gas volume vented during the site blowdown and purge or the vented gas during semi-annual meter calibrations. To put that volume in perspective, for a small location without a compressor operating at 150 psig, the volume vented and later purged would be on the order of 2.5 MSCF—the same volume that would be vented in 131 days of operating a single no-bleed dump valve at 35 psig and 5 cycles/hour. The amount vented and purged during meter calibrations will depend on meter technology selected, but it is far from zero for any technology.

These costs also do not address the 2 weeks of lost production (call it 12 days at an average production rate of 100 MSCF/d) of something like 1,200 MSCF that was either deferred or more likely in competitive reservoirs was allowed to migrate to offset wells. At a $5/MMBTU sales price the cost of this lost production is $600 million across 100,000 wells.

D. Operating costs

Operating costs are the easiest to assess. A measurement tech can handle approximately 200 meter stations. The cost of a measurement tech with vehicle and benefits is $150,000/year which works out to about $750/meter/year or $1,500/site/year.

IV. Conclusion

The idea that there would be any benefit to society from requiring gas measurement of control gas and fuel gas is patently false regardless of your position on the risk to society of gases being released to the atmosphere. A project to put this measurement in place would result in considerable vented gas, excessive capital expenditures, and excessive increases in operating costs. On the other hand the data from this expensive equipment would actually be less representative of the gases released than the current methods. In short, you would be implementing a very large cost to develop less precise data.

Attachment D

API Comments on EPA’s White Paper on Liquids Unloading

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June 13, 2014

Mr. Chris Frantz
US EPA
109 T.W. Alexander Drive
Mail Code: #143-05
Research Triangle Park, NC 27709

Re: EPA VOC/Methane White Paper on Oil and Natural Gas Sector Liquids Unloading Processes

Dear Mr. Frantz:

The American Petroleum Institute (API) appreciates the opportunity to provide feedback on EPA's White Papers on Methane and Volatile Organic Compound (VOC) Emissions in the Oil and Natural Gas Sector. On April 15, 2014, EPA released, for external peer review, white papers that focus on technical issues covering emissions and mitigation techniques targeting methane and VOCs from five separate emission sources. As noted in the Obama Administration's Strategy to Reduce Methane Emissions, EPA will use the papers, along with the input from the peer reviewers and the public, to determine how to best pursue additional reductions from these sources. As described below, API does not believe additional methane controls should be required at this time.

API represents over 590 oil and natural gas companies, leaders of a technology-driven industry that supplies most of America's energy, supports more than 9.8 million jobs and 8 percent of the U.S. economy, and, since 2000, has invested nearly $2 trillion in U.S. capital projects to advance all forms of energy, including alternatives. Many of our members will be directly impacted by any policy decisions that may arise from this effort regardless of whether it informs either regulatory action by the federal government or states.

API provided technical feedback and expertise throughout the development of the New Source Performance Standard (NSPS) Subpart OOOO rule. Each source addressed by the white papers was considered for regulation during the development of the NSPS and EPA, ultimately, chose not to regulate them. While our understanding of emissions from oil and gas production continues to evolve, the fundamental merits of requiring additional regulatory control of these sources is unchanged. As such, API continues to believe that no additional regulation of oil and gas production sources is necessary prior to the full implementation of the NSPS OOOO rule and a subsequent evaluation of emissions.

Considering the potential for significant impact on our members that may arise from any policy decision stemming from the white papers, API has developed significant technical comments (see attached) to address a number of technical inaccuracies about the sources and the conclusions that have been drawn. Barring significant revision, API believes that the current white papers are simply insufficient to inform sound policy decisions and that simply posting comments on the current version will not result in an informed process. As such, API recommends the EPA take the following steps:

- Revise the white papers to correct any fundamental flaws or inaccuracies that were identified in response to peer review and stakeholder comment (e.g., improved source descriptions, improved understanding of emission quantification, misconceptions about emission mitigation options)
- Develop a response to comments document that clearly identify the changes the EPA makes to the revised white papers and explains the Agency's rationale for those changes
- Identify emission studies in progress that will better inform EPA's understanding of these source emissions and await the pending study reports

In recent years, there have been significant swings in the national emission estimates from oil and gas production sources, including those covered by the white papers, which indicate a necessity to continue collecting data to improve our understanding. Much of this learning will come from improved reporting under Subpart W of EPA's Greenhouse Gas Reporting Program as well as current studies and others planned in the coming years, which involve taking direct measurements of the sources. EPA and industry would both be well served by allowing these studies to inform policy.

Again, we appreciate the work by EPA to initiate these white papers and the opportunity to provide feedback on this effort. API and its members are dedicated to working with EPA to improve our collective understanding of these emissions and providing the technical operator experience that's needed to do so. Recognizing the potential for these white papers to inform not only EPA but other government agency policy decisions, we request the opportunity to provide additional feedback to the Agency in response to any of our comments in advance. Furthermore, we again offer our experience and expertise as EPA moves into the policy evaluation phase of this effort.

Sincerely,

/s/

Matthew Todd

Cc: Peter Tsirigotis, EPA

David Cozzie, EPA

Bruce Moore, EPA

Comments on

Oil & Natural Gas Sector
Liquids Unloading Processes

by EPA Office of Air Quality Planning and Standards

June, 2014

Prepared by

The American Petroleum Institute (API)

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Executive Summary

The U.S. Environmental Protection Agency (EPA) has developed a draft document titled *Oil and Natural Gas Sector Liquids Unloading Processes* (referred to as "the White Paper") to, as stated in the Preface, seek input and solidify its understanding of the methane and volatile organic compounds (VOCs) emissions from leaks in this industry sector. The American Petroleum Institute (API) hereby submits its input and comments in this document.

The White Paper does not meet the goal of being a high quality technical document intended as a resource to inform EPA's deliberations regarding emissions due to venting of wells to assist liquids unloading. Rather than a robust compilation and analysis of available information regarding venting of wells to assist liquid unloading, the White Paper appears to be a summary of the information sources referenced. In some instances, the summaries of the underlying sources are incomplete and information is incorrectly mischaracterized. There are misunderstandings and incorrect/inaccurate statements scattered throughout the White Paper and additional information sources, such as the vast amount of industry technical literature regarding management of well bore liquids, are not included in the scope of the White Paper sources. No discussion regarding the limitations of the underlying sources is presented in the White Paper and there is no critical analysis of the accuracy or validity of the underlying sources or the information summarized from them in the White Paper. The logic and underpinning evidence leading to the conclusions and assertions made in the White Paper is not clearly presented.

More clarity of focus on venting of wells to aid liquid unloading, which is the source of emissions, rather than wellbore liquid loading in general would improve the White Paper. Understanding the reasons and causes for using well venting to aid in liquid unloading is the key to understanding and evaluating potential approaches to reduce well venting and emissions. Managing the use of venting to affect liquids unloading should be the predominant focus of the white paper. To adequately evaluate options to reduce venting of wells and the emissions that result, it is necessary to understand the reasons that wells are vented, alternatives to venting that will still provide for well-bore liquid loading management, and the envelope of conditions where these alternatives are feasible. This does not appear to be the focus of the White Paper and adequate information is not provided.

Well-bore fluid dynamics and the portfolio of techniques, practices, and technologies that the industry uses to manage well-bore liquids are complex. Notwithstanding this complexity, the White Paper needs significant improvement in content, organization, and data sources to be useful if is intended to inform EPA's understanding and evaluation of potential options to reduce emissions from venting of wells for liquids unloading.

Following the public announcement that a white paper was being drafted on emissions associated with liquids unloading, API submitted early feedback (March 2014) to EPA and those comments are attached for further consideration.

Highlights of key review comments discussed in more detail later in this document follow:

- Based on deeper analysis of the GHGRP data, emissions from venting for liquid unloading are mostly driven by a relatively small number of operators and a relatively small subset of wells with less than 0.5% (10 of 1991) of the datasets at the "subbasin" level accounting for more than 50% of the emissions. This skewed distribution is consistent with the API/ANGA Survey Report data. This strongly suggests that a targeted type intervention is more appropriate than a broadly applicable regulatory approach.

- Further illustrating the niche issue of venting for liquid unloading, the GHGRP data shows only about 13.5% of U.S. gas wells vented for liquids unloading in 2012. Given the fact that most U.S. gas wells are low producers and likely subject to liquids loading this indicates that managing well-bore liquids without venting is significantly more common than venting.

- The White Paper's assertion that plunger lift systems are an effective emission control technology is not supported by the data that shows wells with plunger lifts have a higher frequency of engaging in venting, a higher number of vents/venting-well/year, and account for a disproportionate percentage of well venting emissions. Despite plunger equipped wells being less than 40% of the wells in the API/ANGA survey they account for about 70% of the emissions.

- The use of advanced formation energy management (smart automation) to aid liquid unloading while minimizing venting, for wells with plunger lift and wells without, is not adequately described.

- The control technology discussions and costs in the White Paper appear to be solely based on lessons learned documents from the Natural Gas Star Program. These lessons learned documents were developed to foster technology transfer, which they are adequate to do, but have never been subjected to the level of critical expert review necessary if they are to be used as foundational technical information sources.

A. Introduction

The description of liquids loading of well-bores is incorrect which indicates a fundamental misunderstanding of well-bore liquid-loading, the techniques and tools that are used to manage liquids loading, and the role that venting has in liquid unloading. Additionally, there are several misunderstandings, incorrect/erroneous statements and use of terms that do not have any meaning in the context of liquid loading of well-bores.

Liquid loading of well-bores occurs when the gas velocity up the well-bore is not sufficient for the gas to transport liquids up the well-bore. When a vertical liquid column builds up in the well-bore, the weight of the column puts back-pressure on the producing formation and can reduce production rate to the point where the well can quit flowing. The volume of flow up a well-bore is a function of the formation deliverability (inflow rate), the **flowing** formation pressure near the well-bore, and the cumulative resistance to flow expressed as pressure drop. The cumulative resistance to flow is the sum of the fluid column in the well-bore's hydrostatic pressure, the flowing friction up the production tubing/casing, surface equipment pressure-loss/back-pressure, and the pressure of the collection line that a well is flowing into. As the cumulative resistance to flow approaches the flowing formation pressure the rate of production will decrease and, if the cumulative resistance equals or exceeds the formation pressure, the formation will cease flowing reservoir fluids into the well-bore. As wells deplete, the formation pressure near the well-bore and the inflow-rate decreases which decreases the volume flow rate of reservoir fluids and consequently the velocity of flow up the well-bore. Wells and reservoirs follow a continuum of flow regimes in their economic life as the reservoir depletes, production goes down, well-bore (tubing) velocity goes down, and liquid loading begins to occur in the well-bore.

The statement that:

> *"the accumulation of liquids in the well can occur when the bottom well pressure approaches reservoir shut-in pressure"*

is not correct and is rendered somewhat meaningless by the use of the term "*reservoir shut-in pressure*" which does not have a meaning in this context. "*Reservoir shut-in pressure*" is more appropriately referred to as "average reservoir pressure" which is defined as the volumetric average fluid pressure within the reservoir across the areal extent of the reservoir boundaries. It is misleading to call the build-up pressure at a well during a shut-in "reservoir pressure".

Techniques and tools that operators use to manage liquid loading **that rely on formation energy** focus on reducing resistance to flow or by raising the pressure in the near-wellbore. Lowering surface pressure with compression, wellsite debottlenecking, or lowering gathering system pressure reduces surface resistance to flow. Reducing flowing fluid friction through materials choices can assist in reducing flowing friction resistance to flow. Hydrostatic resistance is affected by surfactant/soap injection or running plungers to try to reduce the work that is done by the gas in lifting liquids (surfactant/soap) or make it more efficient (plungers). Near-wellbore formation pressure can be impacted by stopping flow to allow reservoir fluids to resupply depleted fluids and pressure near the well bore. Flow velocity can be increased, for a given flow rate, by installation of smaller diameter "velocity" production strings in the well-bore although there is a practical limit to smaller diameters where flowing friction overcomes the effect of a smaller diameter flow path. Venting of wells to atmosphere is used to lower the resistance to flow by removing the collection system and most surface equipment backpressure. A combination of techniques may be used concurrently, such as velocity strings and surfactant/soap injection, dependent on the well and formation characteristics.

Once the formation pressure and inflow rate reaches the stage where the reservoir's energy and flow is not sufficient to lift liquids then energy will need to be added to the well, which is commonly termed "artificial lift" but more properly termed "mechanical deliquification" of gas wells. Added-energy deliquification methods include downhole pumps (e.g., sucker-rod pumps, progressing cavity pumps, or electric submersible pumps) or gas lift which involves injection of higher pressure gas down the casing/tubing annulus and into the flow stream to increase the energy/velocity available for the gas to do work lifting the liquids. Each lift type has its specific purpose with respect to liquid rate potential, solids handling capabilities, installation/maintenance cost, reservoir drawdown potential, etc. Once a mechanical deliquification technique is installed on a well, any perceived value of venting is eliminated and venting will not occur. When the expected production from a well cannot support the investment required to enable deliquification, it will reach the end of its economic life and be abandoned.

The choice of what technique to employ is based on well-by-well and reservoir-by-reservoir analysis and is one of the primary jobs of production engineering teams. For a typical well, as it moves through the depletion continuum, a series of techniques will be employed. The decision on technology selection requires a thorough understanding of the reservoir, conditions that a reservoir is flowing into, the reservoir's sensitivity to backpressure, the volumes and pressures that the deliquification technology must handle, and costs/benefits of applying the technology.

The discussion of venting (also termed "blowing down") a well and the role of plunger lifts is partially incorrect and incomplete. The following are provided to clarify the process.

1. Venting may be either manual or automated and also relies on reservoir energy.
2. Venting may or may not be done in conjunction with shut-in periods to build reservoir energy.
3. Plunger lifts rely on the reservoir energy. Venting to reduce flow resistance and create lift is common while running plungers.
4. Plungers do improve the efficiency of a gas stream to perform liquid removal by providing a physical barrier between the formation energy and the liquid column (reducing liquid drag effects) but do not necessarily minimize or eliminate venting.
5. Minimizing venting, with or without a plunger, hinges on understanding the reservoir energy, flow resistance, and available technologies and techniques (such as shut-in periods to build near well-bore energy) to provide adequate flow rate to lift liquids without venting. Wells with plunger lifts have more variables that can be manipulated to accomplish this goal, but are not inherently able to provide smaller vented volumes.
6. Swabbing is a remedial treatment with a rig or wire-line unit that is used only when a well will not respond to other techniques to remove the liquids from the well-bore and restore flow. It is not commonly used to manage liquid loading on a frequent basis, and volumes vented during swabbing operations will generally be markedly higher than individual venting events.

B. Charge Questions

Charge Question 1

> *Please comment on the national estimates of methane emissions and methane emission factors for liquids unloading presented in this paper. Please comment on regional variability and the factors that influence regional differences in VOC and methane emissions from liquids unloading. What factors influence frequency and duration of liquids unloading (e.g., regional geology)?*

The "Introduction" section and Section 2.0 of the white paper incorrectly represents the data sources and information summarized as "studies". Only one of the information sources summarized, the UT Phase 1 study, is an actual emission study. The other data sources summarized (i.e., the National Inventory, the GHGRP data, the API/ANGA report, and the ICF/EDF report;) are inventory estimates and/or reports rather than basic measurement studies and should be discussed and characterized as such. These same sections also state that some information sources summarized include information regarding mitigation techniques which is not correct. What some of these information sources do include is information regarding well-bore configuration, specifically information regarding the number or percentage of wells that have plunger lift systems. As discussed later, plunger lift systems are not an emissions "mitigation technique" by any definition of the term.

Section 2.0 of the paper would benefit from inclusion of a table showing the different estimates of emissions attributed to venting of wells to aid liquids unloading at the beginning of the section.

Table 1

Well Venting for Liquid Unloading Methane Emission Estimates

Name	**Methane MT's**	**Total # of Venting Wells**	**# Venting With Plunger Lift**	**# Venting Without Plunger Lift**	**MT's per year per Venting Well**	**MT's per Venting Well per year with Plunger**	**MT's per Venting Well per year w/o Plunger**
Greenhouse Gas Reporting Program - 2012	276,378	58,663	32,448	26,215	4.711	6.158	2.959
U.S. Inventory of Greenhouse Gas Sources and Sinks - 2013 (2011 Emission Year)	258,667	60,810	23,503	37,307	4.254	4.618	4.024
API/ANGA Report - 2011 data	319,664	65,669	36,806	28,863	4.868	5.207	4.584
UT/EDF Phase 1 Study	162,619			35,828	4.539	not measured	4.539
ICF/EDF Report	277,307	75,399	44,286	31,113	3.678	4.430	2.607

Note: With the exception of the UT/EDF Phase 1 Study this table is U.S. Totals

Note 2: The UT/EDF Phase 1 results should be viewed with an abundance of caution. Only 9 well venting instances, all without plunger lift, were measured which is much too small of a population to extrapolate to a national or even sub-national level. Also, the supplemental information for this study indicates that venting may have been triggered on at least some of the wells measured solely to enable measurement. If this is correct, the wells were not liquid loaded, the flow volumes and dynamics would be very different from a liquid loaded well, flow would likely exceed normal production flow of the well, and flow would not be representative of an actual venting to assist unloading.

Note 3: The different data sources/studies used different methane concentrations to arrive at methane emission estimates. See the individual studies for information on methane content that was used.

a. GHGRP Data - 2012 emission year:

The GHGRP data is likely the most complete and data rich source of available information regarding the number of wells venting to aid liquids unloading, the number of plunger lift systems installed in wells, the frequency of venting, and estimated emissions. The GHGRP discussion in the white paper does not include or indicate the significant amount of information available, the granularity of information available (down to the county/formation-type combination and below), or even a cursory analysis of the emission data.

Liquid unloading is reported into the GHGRP at the sub-basin category (county & formation type) level for methods 2 and 3. For method 1, reports are made at the level of unique combinations of sub-basin category (county & formation type); pressure group (5), and tubing diameter group (3). Rather than the 251 basin level reports the white paper notes, there are

1,993 separate data sets available at the granularity described. Estimates for GHGRP reporting of emissions from venting to aid liquid unloading are based on engineering calculations (Methods 2 & 3) or representative well vent measurement and extrapolation to other venting wells in the same grouping combination (Method 1).

Data available for the 2012 emission year, for methods 2 and 3 include

1) Count of wells vented to the atmosphere for liquids unloading.
2) Count of plunger lifts.
3) Cumulative number of unloadings vented to the atmosphere (**Deferred in the 2012 data**).
4) Average internal casing diameter or tubing diameter, for all wells, where applicable.
5) Annual CO_2 and CH_4 emissions, expressed in metric tons CO_2e for each.

Data available for method 1 includes

1) Count of wells vented to the atmosphere for liquids unloading.
2) Count of plunger lifts.
3) Whether the selected well in each group had a plunger lift (yes/no).
4) Cumulative number of vents to the atmosphere for liquids unloading.
5) Average flow rate of the measured well venting in cubic feet per hour.
6) Internal casing diameter or internal tubing diameter in inches, where applicable,
7) Well depth of each well, selected to represent emissions in that tubing size and pressure combination.
8) Casing pressure, of each well selected to represent emissions in that tubing size group and pressure group combination that does not have a plunger lift.
9) Tubing pressure, of each well selected to represent emissions in a tubing size group and pressure group combination that has a plunger lift.
10) Annual CO_2 and CH_4 emissions, expressed in metric tons CO_2e for each gas.

As this illustrates, the GHGRP data includes a large amount of information that can be analyzed to help understand well venting to aid in liquids unloading.

Additional information will be available in data reported in 2015, including items shown as deferred above. However, caution needs to be taken when using this data to perform enough QA/QC to identify and exclude obviously incorrect data. For example, some data sets report emissions that are dominated by CO_2 (some 100% CO_2) which is not likely and the number of plunger lifts reported by some reporters under method 3 is extremely large which indicates these reporters did not correctly interpret the data field.

A basic analysis of the reported data indicates that

- 10 of the 1993 data sets (0.5%) reported at the granular level account for just over 50% of the CH_4 emissions reported for venting to aid in liquids unloading during 2012 with the top 72 (3.6%) accounting for just over 75%.
- At the facility (basin) & reporter level (251 non-zero data sets) the top 1 (0.4%) accounted for about 37% of the total reported emissions, the top 3 (1.2%) accounted

for over 50% of the total CH4 reported, and the top 20 (7.9%) accounted for over 75%.

- At the parent company level (99 total), the top 2 account for over 50% of the reported CH4 emissions and the top 11 account for over 75% of the reported CH4 emissions.

As this analysis shows the reported emissions are dominated by a small sub-set of the data sets reported which implies a targeted intervention effort for emission reduction is more appropriate than a broader regulatory effort. The top reporting companies are very much aware that their operations have been unfavorably illuminated in the GHGRP and are making significant efforts to alter operations so that they will not be singled out in future reports. This is a positive outcome of the transparency provided by the GHGRP data.

<u>Limitations of the GHGRP data:</u> The data regarding liquids unloading in the GHGRP provides only partial coverage of the industry due to the 25,000 metric tonne CO2e reporting threshold. EPA has estimated the extent of coverage at 85%. Reported data indicated 'Best Available Monitoring Methods" (BAMM) was used for some parameters in some data sets.

b. API/ANGA 2012 Survey Data:

Some of the conclusions that the white paper attributes to the API/ANGA survey report are not actually made in the report by the survey report authors. The white paper states:

> *The authors of the study made the following conclusions:*
>
> - *The 2012 GHG Inventory emissions estimates for liquids unloading were overestimated by orders of magnitude. The API/ANGA Survey data indicated a lower percentage of gas wells that vent for liquids unloading and a shorter vent duration.*
> - *The emissions from liquids unloading are not specific to only conventional wells, but can be for any well depending on several technical and geological aspects of the well.*
> - *Although most wells do not require liquids unloading until later in the well's productive lifetime, the timeframe for initiating liquids unloading operations varies significantly and can be early in the well's productive life span.*
> - *Most of the emissions from liquids unloading operations are produced by less than 10% of the venting well population.*

These may be conclusions made by the white paper authors based on their interpretation of the API/ANGA report information and if so should be identified as such. However, there was no information provided in the API/ANGA report referenced that would provide the information necessary to reach either of the last two bulleted conclusions. Unless the white paper authors can provide the source of the conclusions attributed to the API/ANGA report and correctly attribute them, they should be removed.

The API/ANGA report also reported the percentage of wells with artificial lift (mechanical deliquification) installed (7,329 of 54,660 - 13.4%) which is relevant as these wells have no potential for venting to help unload liquids.

c. U.S. Inventory of Greenhouse Gas Sources and Sinks - 2014:

The White Paper discussion of the 2014 U.S. Inventory of Greenhouse Gas Sources and Sinks (NEI) is somewhat incomplete in that it does not discuss the limitations of the inventory estimate for liquid unloading or the difference in the ratio of wells venting for liquid unloading with and with/out plunger lifts from the other information sources. As Table 1 above shows, the ratio of venting wells with plunger lift and those without plunger lift in the NEI is opposite the ratio in the API/ANGA survey report, the GHGRP data, and the ICF/EDF report. This is likely due to the decimation of the API/ANGA data into NEMS regions, which yields smaller data sets for each NEMS region, with subsequent analysis at the NEMS region level to estimate activity data and emission factors. It is likely that the different ratio is an artifact of analysis of smaller data sets at the NEMS region level and hence not representative of the national well population.

d. UT Emission Measurement Study:

The White Paper discussion of this study's measurement of liquid unloading events does not appropriately stress the limitations of the study. Since only 9 well-venting instances were measured and none had plunger lift installed the unlikely representativeness of these 9 measured events should be stressed. Although the White Paper does mention the author's cautions regarding the representativeness of the measured venting events and extrapolation to a larger population, these cautions should be stressed. As the UT paper authors clearly state: *"Because the characteristics of the unloading events sampled in this work are highly variable, and because the number of events sampled is small, extrapolating the results to larger populations should be done with caution."*

Additionally, the UT study report noted that: *"In this work, sampling was performed for unloadings in which an operator manually bypasses the well's separator. Unlike automated plunger lift methods, these manual unloading events could be scheduled, allowing the study team adequate time to install measurement equipment."* This implies that wells may have initiated venting solely to enable measurement and hence may not have been "liquid loaded". If correct, the measured flow during the venting would likely be different (likely higher) than flow from the same well if the well-bore was liquid loaded.

e. ICF/EDF Report:

<u>Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF International, 2014)</u>

The White Paper representation that the ICF/EDF report based the 2011 estimate of the number of wells venting with and without plunger lifts and estimated emissions on the 2013 NEI is not consistent with the ICF/EDF report. As the following excerpts from the ICF/EDF report clearly notes, the GHGRP data for 2011 and 2012 (presumably averaged) was used to establish the "activity count" and "emission factor" for the baseline liquid unloading: *"Data reported to* *subpart W for 2011 and 2012 was used to develop new activity and emission factors for wells with liquids unloading. From the subpart W data analysis, the number of wells venting with plunger lifts was reported to be 37,643 and the number of wells venting without plunger lifts was reported to be 26,451. It was assumed that subpart W covers 85% of reporters, so the number of venting wells was increased to 44,286 and 31,113, respectively." "The emission factors were also updated using the data reported to subpart W for 2011 and 2012. The total emissions for each venting well type (plunger lift versus non-plunger lift) were divided by the total number of reporting wells in order to obtain the new emission factors. From this analysis, the calculated emission factors were 277,000 scf/venting well for wells with plunger lifts and 163,000 scf/venting well for wells without plunger lifts."*

Also, the White Paper should clearly note that the ICF/EDF baseline estimates for venting of wells for liquid unloading does not represent any "new" information and is simply an analysis and "gross-up" of the GHGRP data.

Charge Question 2

> *Is there further information available on VOC or methane emissions from the various liquids unloading practices and technologies described in this paper?*

API provided supplemental material and analysis from the 2012 report "Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production: Summary and Analysis of API and ANGA Survey Responses (API and ANGA, 2012)" to the EPA National Inventory team. This information provided additional detail, analysis, and derivation of emission factors for both plunger and non-plunger equipped wells. The following table shows a summary of the information furnished that was not reviewed or included in this report.

Calculated national # wells w/plunger lift that vent for unloading	36,806	Wells
Calculated national # wells w/o plunger lift that vent for unloading	28,863	Wells
Calculated # vents for wells w/plunger lift	344	vents/venting well-yr
Calculated # vents for wells w/o plunger lift	33	vents/venting well-yr

Emission Factor per vent

Calculated EF: gas emissions per unloading vent for wells w/plunger lift	1,005	scf gas/unloading vent
Calculated EF: gas emissions per unloading vent for wells w/o plunger lift	9,336	scf gas/unloading vent

Emission Factor per well

Calculated EF: gas emissions per well for venting wells w/plunger lift	345,343	scf gas/venting well-yr
Calculated EF: gas emissions per well for venting wells w/o plunger lift	304,048	scf gas/venting well-yr

It is important to note that the total number of wells using a venting technique to assist in unloading liquids was 65,669 wells. If there are 504,000 gas wells then this number is 13% of the total. Any administrative or regulatory action should be focused at this small subset of the wells rather than being a broad-brush approach to burden the entire population of gas wells with restrictions that are unnecessary.

Additional information providing background on well-bore liquids loading, techniques and tools used to manage liquid loading, and the role of venting to aid liquids unloading can be found in the Subpart OOOO docket. The information in the Subpart OOOO docket should be accessed and characterized in the White Paper. A massive amount of information regarding well-bore liquids loading, management of well-bore liquids, and deliquification technologies and techniques is available in the oil and gas industry technical literature. A good place to start accessing this information is Gas Well Deliquification portion of the "Artificial Lift R&D Council (ALRDC)" website at http://www.alrdc.com.

Limited information regarding emissions from well venting to aid liquids unloading and the reductions achieved by actions/projects to reduce venting are available in the Natural Gas Star archives of Technology Transfer Workshops and Annual Implementation Workshops can be found at the EPA's Natural Gas Star website http://www.epa.gov/gasstar/workshops. For example, several updates to the BP "Smart Automation" well unloading management, referenced in the white paper, have been presented with the latest in February of 2014.

Charge Question 3

> *Please comment on the types of wells that have the highest tendency to develop liquids loading. It is the EPA's understanding that liquids loading becomes more likely as wells age and well pressure declines. Is this only a problem for wells further down their decline curve or can wells develop liquids loading problems relatively quickly under certain situations? Are certain wells (or wells in certain basins) more prone to developing liquids loading problems, such as hydraulically fractured wells versus conventional wells or horizontal wells versus vertical wells?*

EPA's understanding is somewhat correct in that older wells do have a greater tendency to develop liquid loading problems due to decreased production rate - not pressure. The physical model that describes how free-flowing wells (including wells venting without plungers) is a "drag model" that describes the physical action of high-velocity gas flow dragging liquid packets at the no-flow boundary between the liquid and the gas. In this model, pressure is a secondary effect and the action of the gas on the liquid is dominated by the gas velocity. A more correct understanding would be that lower production rate wells have a greater susceptibility to liquid loading due to decreased velocity - which often occurs in older wells as production rate declines. However, liquid loading issues can and do occur in newer wells with inadequate velocity to lift the amount of liquids produced by the well. Absent a plunger-lift barrier between the well-bore liquid load and the formation, the formation pressure is not the relevant characteristic leading to liquid loading.

Whether a well is hydraulically fractured or completed with other stimulation technique has nothing to do with when it might experience problematic liquids loading. Whether a well is vertical or horizontal is also not relevant to when a well may experience problematic liquid loading. One could speculate that to the extent that hydraulically fracturing a well or drilling a horizontal section raises the production rate from a well then such wells would have fewer tendencies to experience problematic liquid loading until later in their life-cycle. For example:

- A well making 3 MMSCF/day may begin experiencing liquids loading in certain high liquids production situations—these liquid loading problems will normally be addressed by adding a mechanical pump, not plungers or venting.
- A well making 50 MSCF/day experiencing liquids loading will typically be evaluated for lower cost deliquification methods like adding a plunger or putting the well on intermittent (shut-in) or vent cycles. Onset of liquids-loading is a function of a very wide range of physical parameters and appropriate responses require evaluation of all of those parameters.

Charge Question 4

> *Did this paper capture the full range of feasible liquids unloading technologies and their associated emissions? Please comment on the costs of these technologies. Please comment on the emission reductions achieved by these technologies. How does the well's life cycle affect the applicability of these technologies?*

Prior to discussion of individual technologies, techniques, and practices to manage well-bore liquids and venting to aid deliquification, the White Paper should acknowledge the complexity of the issues. Dealing with liquids-loading issues is a very complex mix of engineering and economics applied to an individual well. The appropriate approach to managing well-bore liquids in an individual well will likely change as the well progresses through its life-cycle. Attempting to describe the applicability of individual techniques to the wide range of U.S. gas wells is not an appropriate approach and runs the risk of severely constraining innovation. Well deliquification is a fundamental challenge for continued production from the majority of US gas wells and the proportion is expected to grow with new growth concentrated in non-traditional gas reservoirs such as shales, coal-beds, and tight-gas sands which are susceptible to liquid loading. Managing wellbore liquids loading is a primary focus for production engineers and operations teams. A very large amount of industry focus, research, and attention is applied to gas-well deliquification with innovation and research continually underway. Research and work regarding managing well-bore liquids aims to both optimize and improve existing techniques along with developing entirely new types of systems. The flexibility to pilot some of these ideas/developments must be preserved – even if they ultimately do not succeed.

a. AVAILABLE LIQUIDS UNLOADING EMISSIONS MITIGATION TECHNIQUES

The introductory paragraphs in this section of the White Paper illustrates misconceptions in the understanding of liquid loading of wells, venting to aid in unloading liquids, and approaches to minimize venting.

As previously noted above, the statement that

> *As the bottom well pressure approaches reservoir shut-in pressure, gas flow slows and liquids accumulate at the bottom of the tubing.*

is not correct. "Reservoir shut-in pressure" has no meaning in relation to liquid loading of well-bores. What is important is the flow rate into the well-bore and the flow velocity up the tubing in the well.

The introduction of the term "blowdown" as an analogue to venting of wells to aid in liquid unloading is simply unnecessary and may be confusing to some readers. In the subsequent discussion, the White Paper discusses "blowdown" as a stand-alone approach to unloading well-bore liquids. While this may be correct in some instances, venting of wells to aid in unloading well-bore liquids is common in conjunction with some other approaches discussed - such as plunger lifts.

The statement that:

> *These technologies can reduce the need for liquids unloading operations or result in the capture of gas from liquids unloading operations.*

is incorrect in its understanding. What the technologies subsequently discussed can do is reduce the need for or practice of **venting** to aid in unloading liquids - unloading of well-bore liquids still must be accomplished. Also, dependent on the technique applied, gas not vented may be retained in the reservoir or produced - it is not *"captured from liquid unloading operations."*

b. Section 3.1"Liquid Removal Technologies"

This section of the White Paper has several errors, misunderstandings, and omissions.

There is no discussion of the limitations of the Natural Gas STAR program documents and partner presentations. The White Paper should be very clear that the Natural Gas STAR Lessons Learned documents are not peer reviewed, generally represent a compilation of information furnished by Natural Gas Star partners and studies commissioned by EPA, are generally compiled and written by an EPA contractor, and have not been rigorously reviewed by industry or other experts in the subject matter. Partner presentations are similar in that they have not been rigorously reviewed and typically describe an individual project or application of a technology or technique rather than a broad application. For technology and practice sharing the level of review and scrutiny was appropriate and the Lessons Learned, Partner Reported Opportunities, and Partner Presentation documents are useful and valuable. However, extrapolating these Natural Gas Star documents to the broad US population of wells and compiling the information to inform public policy, as the White Paper purports to do, demands a higher level of review and validation of the underlying information - which is lacking in the White Paper.

Some of the actions listed in the White Paper that the Natural Gas Star program reports are taken when liquids unloading occur are not correct. For instance:

> *Shutting in the well to allow the bottom hole pressure to increase, and then venting the well to the atmosphere (well blowdown),*

This statement is not correct. Wells may be vented without a shut-in cycle. A shut-in cycle can temporarily increase bottom-hole pressure near the well-bore and, more importantly, well inflow and production rate which will increase flow velocity when the well is flowed - either to production or atmosphere. Wells are often shut-in, a technique known as intermitting, either manually or more commonly via automation to temporarily increase well inflow and production rate and enable liquid lifting while producing into a collection system.

> *Swabbing the well to remove accumulated fluids,*

The White Paper presents swabbing as a technique commonly used to manage well-bore liquid loading. In practice, swabbing is a remedial treatment with a rig or wire-line unit that is used only when a well will not respond to other techniques to remove the liquids from the well-bore and restore flow. It is expensive and hence not commonly used to manage liquid loading on a frequent basis.

The White Paper does not discuss “intermitting” as a technique to manage liquid loading of well-bores and potentially reduce venting. Intermitting is a technique where producing periods are interspersed with shut-in periods to allow the reservoir to “refill” the area around the well-bore that has been partially depleted during the producing period. The shut-in periods enable temporarily higher production rates and can enable velocities sufficient to lift liquids while producing rather than venting.

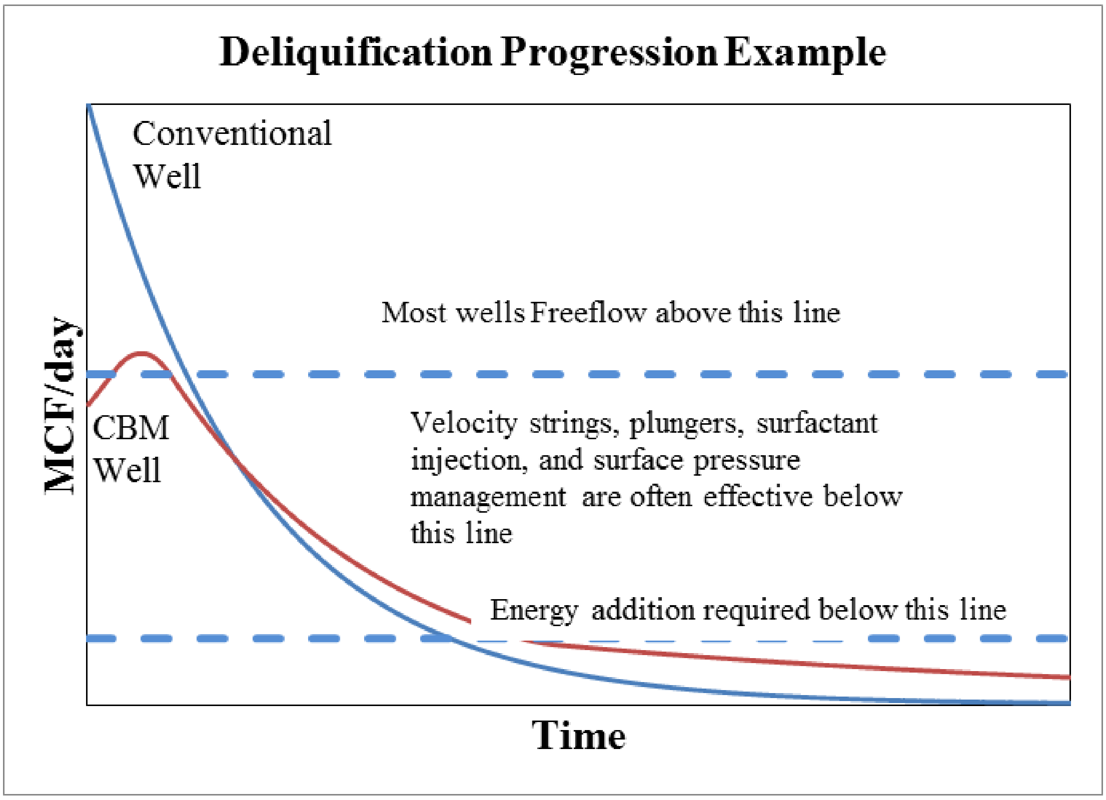
The discussion of “smart automation” techniques, either coupled with plunger lifts or on wells without plunger lifts, in the White Paper is incomplete. The key to managing well-bore liquid loading while minimizing venting is understanding, managing, and using reservoir energy not installing or running plunger lift systems or other techniques to aid well-bore liquid management. One approach to smart automation systems (but not the only possible approach) works by optimizing the management of individual well flowing and shut-in times to enable unloading of well-bore liquids without venting. This approach is applicable to both wells with plunger lifts and wells without plunger lifts although wells with plunger lifts have more variables for the system to manipulate. The basic concept is: “The reservoir does not quit working when a well is shut-in”. Producing a well creates a zone of lower pressure and lower inflow capacity near the well-bore. During shut-in, when the well is not flowing, the reservoir will continue to flow into the depleted zone and partially replenish the reservoir. When a well starts flowing after a shut-in period it will temporarily have higher inflow (production) rate (often termed flush production) and higher pressure available. The higher production rate may provide adequate velocity to lift liquids while producing in the absence of a plunger lift and the higher pressure may provide adequate energy to lift a plunger and its load while producing without the need for venting. Although the potential benefits of such an approach are briefly discussed in the White Paper, much more emphasis and discussion should be devoted to this subject.

The BP “smart automation” project discussed in the documents referenced in the White Paper (British Petroleum (BP) 2006; U.S. EPA 2006a; and U.S. EPA 2011) provides an excellent case study example of the application of understanding and optimizing reservoir energy management to sharply minimize venting associated with liquid unloading. However, the BP project is somewhat mischaracterized in both U.S. EPA 2006a and U.S. EPA 2011 as a project to install plunger lift systems in conjunction with “smart automation”. The actual nature and success of the project was to optimize the frequency and duration of shut-in times on individual wells and plunger cycle timing on wells with plungers through the use of automation that learned the performance of each well and then optimized the cycle parameters for that well – i.e. “smart automation”. This was and is a project about managing reservoir energy not about installing or running plunger lift systems. About half of the wells which were venting were plunger equipped and about half were not plunger equipped. Both plunger equipped and non-plunger wells were previously vented in order to generate the flow or pressure differential necessary to lift liquids. Also, the references to this project in the White Paper are incomplete. Updates regarding this project were presented at the 2007 Natural Gas Star Annual Implementation Workshop and several times since with the latest at the Denver, CO and Park City, UT Technology Transfer workshops in 2014.

Splitting the techniques used to manage liquid loading into “primary” and “remedial” technologies in the White Paper is not useful from the standpoint of improving understanding regarding minimizing venting to assist deliquification. A more appropriate approach would be to split the technologies into those that rely on reservoir energy for unloading liquids and those that add energy to the well-bore to unload liquids. Plunger lift, velocity tubing, intermitting, soap/surfactant injection, and reducing surface pressure via de-bottlenecking or compression all rely on reservoir energy. Down-hole pumps, of various types, and gas-lift add energy to the reservoir fluids. Conceptualizing technologies/techniques in this manner enables consideration of approaches to minimize venting at each stage of a wells life-cycle and in conjunction with each technology/technique used.

Wells and reservoirs follow a continuum of flow regimes in their economic life as the reservoir depletes, production goes down, well-bore (tubing) velocity goes down, and liquid loading begins to occur in the well-bore. In the early stage of a well’s life many (but by no means all) wells can flow freely and with sufficient velocity to avoid liquid loading problems. As the reservoir energy depletes and the production-rate declines, a well will reach the stage where liquid-loading begins to be a problem and one of a portfolio of technologies or techniques will be used to help lift liquids using the reservoir’s energy. As a well continues to produce and the reservoir energy declines further, a well will reach the stage where the reservoir’s energy is not sufficient to lift liquids and mechanical lift energy, in the form of pumps, gas lift, etc., will have to be added to continue producing. When the expected production from a well cannot support the investment required to enable deliquification, it will reach the end of its economic life and be abandoned.

The following figure shows a generalized well life-cycle curve with these different stages of a wells life illustrated.



To address this normal well/reservoir depletion and assist liquid lift a number of techniques are used – dependent on the well configuration, reservoir properties, well depth, and surface equipment and collection system. The choice of what technique to employ is based on well-by-well and reservoir-by-reservoir analysis and is one of the primary jobs of production engineering teams. For a typical well, as it moves through the depletion continuum, a series of techniques will be employed. The decision on technology-selection requires a thorough understanding of the conditions that a reservoir is flowing into, the reservoir's sensitivity to backpressure and the volumes and pressures that the deliquification technology must handle, and costs/benefits of applying the technology. Operators must have the flexibility to choose the most appropriate and cost effective approach for each individual well/reservoir/age/production combination and the regulatory certainty to underpin continued investment. Minimizing venting associated with liquid unloading is part of this ongoing evaluation.

c. Costs

Stating generic costs/cost-ranges and/or economics for any of the technologies or techniques discussed is fraught with difficulty and error. Costs and economics are as variable as the wells and reservoirs they are applied to and any problems or difficulties encountered. There are documented cases where installing a plunger in a well has cost several hundreds of thousands of dollars when other problems were encountered upon pulling the tubing to set a profile nipple for a bumper spring. Certainly such costs are germane to the discussion since it is a possible outcome of any decision to work on a well. There is simply no way to state generically where most wells are within their performance lifecycle, how they will respond to a technique/technology, or what the costs and economics of application will be. One well may be economic at 20 MSCF/day while another might be plugged when the rate reaches 150 MSCF/day. The difference is a complex mixture of reservoir performance, market-price differentials, level of capitalization, and operating costs. These variations are what drive evaluation of individual wells for the appropriate selection and application of technologies/techniques to manage liquid loading or a decision to plug a well that can no longer support the costs of deliquification. Retaining the flexibility to make individual well-appropriate technology-decisions is fundamental to the continued economic production of a great many gas wells in the U.S.

d. Section 3.1.1 Plunger Lifts:

The assertion in the White Paper that installation of plunger lift systems is an emission (venting) control technique is not correct, not supported by the emission data, and not underpinned by a logical or technical analysis in the White Paper. Plunger lifts are a valuable, effective and commonly used methodology/tool to assist in managing well-bore liquid loading. Plunger lifts do increase the efficiency of liquids removal from wells by the reservoir energy and hence do help maintain or increase production. However, the efficacy of plunger lifts in reducing venting of wells deliquification and emissions is completely dependent on how they are operated. As the API/ANGA survey report, the GHGRP data, the U.S. Emission Inventory, and the ICF/EDF report reanalysis of the GHGRP data shows, venting wells with plungers have higher emissions per well than venting wells without plunger lifts. Despite the API/ANGA survey report estimate that only about 36% of U.S. gas wells are equipped with plunger lifts (of which only a subset vent), venting of wells with plunger lifts constitute the majority of venting wells and emissions. Wells with plunger lift systems comprised ~55% of the more than 58,000 wells reported as venting for liquids unloading into the GHGRP for 2012. From an emission perspective, wells with plunger lift systems accounted for about 72% of the GHGRP reported emissions from well venting for liquids unloading. The GHGRP reported data is broadly equivalent to that reported from the API/ANGA survey. With the API/ANGA survey outcome of about 36% of the well population being equipped with plunger lift systems yet responsible for over 50% of the venting wells and 70% of the emissions, **the efficacy of plunger lift systems as an emission control measure is clearly not supported by the data**. However, with advanced well liquids unloading management (management of reservoir energy), large reductions in the frequency of well venting and thereby emissions resulting from liquids unloading, from both plunger and non-plunger equipped wells, can likely be made.

e. Table 3.1 Plunger Lift Review Comments:

- The statement in the Applicability column that

  > *"Candidate wells for plunger lift systems generally do not have adequate downhole pressure for the well to flow freely into a gas gathering system"(U.S. EPA, 2006b)."*

  is incorrect. By definition, plunger lift systems are dependent on reservoir energy, specifically downhole pressure, to lift the plunger and the water/fluid load in the well-bore. Adequate differential pressure must exist between the reservoir pressure and the sum of liquid column hydrostatic pressure, flowing friction pressure loss, surface equipment pressure loss, and collection system back-pressure in order for a plunger to return to surface with the liquid load. Adequate differential pressure may be generated by using shut-in cycles to increase downhole pressure or by using venting cycles to remove surface and collection system back-pressure. The key to minimizing venting associated with plunger operation lies in how you achieve adequate differential pressure to enable a plunger to lift into the producing system rather than venting to atmosphere.

- Cost ranges: The cost ranges in Table 3.1 appear to be copied directly from the underlying documents cited and do not appear to be updated to current dollars. This significant oversight should be corrected in the White Paper. Also, the costs and economics extracted from the underlying documents were predominantly based on Gas Star partner reports and likely reflected installations of plunger lifts that had already been determined to be appropriate for the individual wells where they were installed based on a well-by-well evaluation by the companies making the installations. The resultant cost and economic profile would likely be very different than installations done on a basis different than well-by-well evaluation.
- The statement in the "Efficacy and Prevalence" column of the Table 3.1 plunger lift section that *"The EPA has learned plunger lift systems rely on manual, onsite adjustments."* is not uniformly or even mostly accurate. A large percentage of plunger lift installations are controlled with automated plunger control systems rather than manually operated. Increasingly, these systems incorporate the capability to identify problems and make immediate adjustments. Techniques with telemetry, electronic data collection, and troubleshooting software continue to improve plunger-lift performance and ease of use. A cursory review of plunger vendor websites show that most/all offer advanced plunge control systems that optimize plunger efficiency. Several links to examples are:

  http://www.weatherford.com/Products/Production/PlungerLift/
  http://www.pcslift.com/plungerlift/plunger_products.html
  http://www.pcslift.com/PDFs/PCSFerguson_PLMgr.pdf

- Information regarding the prevalence of plunger lifts is missing from Table 3.1. As the API/ANGA survey report noted, about 36% of the U.S. gas wells are equipped with plunger lifts.

f. Section 3.1.1 - Plunger Lift Narrative Review Comments:

The introductory paragraph of this section is incomplete and somewhat misleading.

> *"Based on our assessment of the data, a plunger lift system for liquids unloading is capable of performing liquids unloading with little or no emissions. The level of emissions depends on how the plunger lift system is operated, specifically, whether gas is directed to the sales line or vented to the atmosphere. There may be potential for improved production and emissions reduction when paired with a smart well automation that optimizes production and reduces product losses to the atmosphere."*

As discussed above, the key to minimizing venting of wells equipped with plunger lifts is how the differential pressure necessary to lift a plunger and its load is achieved. If this is accomplished through vent cycles then venting emissions are likely to be high for a well equipped with a plunger. Conversely, if this is accomplished by using shut-in cycles to manage the reservoir pressure build-up then venting emissions are likely to be much lower. Using a plunger control system, "smart automation", system that optimizes the operation of the plunger on an individual well to achieve maximum unloading/production and minimum venting/emissions is likely to reduce venting/emissions to just instances where overloading occurs due to system malfunctions or high reservoir liquid/water production surges. Differences in approach to operation of plunger lift equipped wells are mostly due to differences in the approach/philosophy that operators take to managing reservoir energy and somewhat due to differences in reservoir characteristics.

The description of a plunger lift system should clearly note that this is an example only and that other configurations are common. Also, the White Paper should describe the broad range of plunger types and configurations available along with noting the significant amount of ongoing development and research devoted to improving plunger lifts and their operation. For example, continuous-run flow-through plungers are available that have a higher liquid volume lift capacity and are appropriate for some wells. Also recently available are flexible plungers designed for use in wells with quite high deviation from vertical - which is becoming more common with multi-well pad development. Additionally, Figure 3-1 page 21 shows a “gas lift valve” on the bottom of the tubing. This valve is not part of the required bottomhole assembly for plunger operation.

As discussed above in the Table 3.1 comments, the costs and economics of plunger lift installations appear to be extracted directly from the underlying documents referenced, are not updated to current dollars, and are predominantly based on costs and benefits reported by Natural Gas Star partners that have been compiled by an EPA contractor in the underlying documents. These costs are seriously outdated and need to be updated using an escalator for oil and gas equipment and labor which has been higher than the consumer price index (CPI) since 2000. It is strongly suggested that EPA engage industry operators and plunger lift suppliers in a survey to gather updated costs.

The White Paper summary of the ICF/EDF report fails to highlight that the 95% reduction in venting, that drives the economics of plunger lift installation summarized, is based on a simply asserted reduction that is not underpinned by any analysis in the ICF/EDF report. The White Paper does not analyze or validate this assertion. The ICF/EDF capital and operating cost assumptions summarized in the White Paper have similar issues.

g. Section 3.1.1 - Artificial Lift Systems:

The discussion of artificial lift systems in both Table 3.1 and the White Paper narrative omits several technologies/techniques and pump types used in mechanical deliquification (artificial lift).

There is no mention of gas lift, which involves injection of higher pressure gas down the casing-to-tubing annulus in order to increase the flow up the tubing thereby increasing the velocity and capacity to lift liquids. Gas lift typically requires additional compression and piping at the surface which requires either electricity to drive compressors or engines to drive compressors – all of which add emissions, complexity, reliability concerns, and operating costs. Also, gas lift is limited to those reservoir/well combinations where the gas injected down the well will flow up the well-bore and not simply dissipate into the formation.

The discussion of pumps focus solely on beam pumps (also termed rod pumps, beam lift pumps, and pumpjacks in the White Paper) and omits progressing cavity pumps and electric submersible pumps. Although not as prevalent as beam pumps, these pump types are used for deliquification of gas wells. Also, omitted from the White Paper is any discussion of linear pumps, both coupled with a rod pump (replacing the walking beam), and in downhole applications. Considerable development and research is being applied to pump technology and linear pumps are one fairly recent outcome with ongoing improvement expected.

The reference to "downhole separator pumps" in Table 3.1 is not recognized as a technology that exists. If a valid technology, the White Paper should provide a detailed description of this technology and the nature and extent of its use.

The costs shown for artificial lift installations have the same problems as costs shown for other technologies/techniques. They appear to have been extracted directly from the underlying sources referenced and have not been updated to current dollars and appear to be based on limited reports by Natural Gas Star partners in the underlying documents. Also, costs are very well-specific, company specific, and technology specific. Generalizing these costs is not appropriate.

Omitted from Table 3.1 is information from the API/ANGA survey report that 13.4% of the wells reported in the survey have some form of mechanical deliquification (artificial lift) installed. This is important and should be included. The statement in Table 3.1 that *"The EPA does not have information on the prevalence of this technology in the field."* is incorrect.

h. Section 3.1.1 - Velocity Tubing:

The discussion of velocity tubing in Table 3.1 and the narrative omits any discussion of the trade-off between increased potential velocity with a smaller x-section of flow and increased flowing friction inherent in smaller diameter tubing which inhibits flow and hence velocity. In practice this trade-off limits the practical minimum diameter of velocity strings to about 1 - 1.5 inches. Although a review of the underlying documents referenced by the White Paper is beyond the scope of these comments, the statement in U.S. EPA 2011 that *"Coiled tubing may also be used, allowing for easier installation and the application of a greater range of tubing diameters as small as 0.25 inches."* is incorrect and needs to be corrected.

The excerpt from U.S. EPA 2011 in Table 3.1 that notes *"Seamed coiled tubing may provide better lift due to elimination of turbulence in the flow stream (U.S. EPA, 2011).* is based on an unsupported assertion in U.S. EPA 2011 that makes vague reference to unidentified "studies" reaching this conclusion. This reference should be removed from the White Paper unless substantiated.

The range of flow rates or life-cycle stages where velocity tubing may be applied in both Table 3.1 and the narrative discussion are simply not correct. Any tubing string placed within the production casing can be thought of as a "velocity string". The well operator is using velocity (at the price of increased friction drop) to keep the gas flow above some "critical value" that is required to allow the gas to reliably lift the liquid. It is correct that smaller diameter tubing strings are used to increase velocity and the ability of gas to lift the liquid. However, the range of production rates and water loading where smaller diameter tubing may be a benefit is considerably broader than represented in the White Paper. Candidate wells and the appropriate tubing diameter are selected based on a modeled calculation of "critical velocity" based on the physics of fluid flow and flowing friction. That critical velocity value is not 1000 ft/min (16.67 ft/sec), as stated in the White Paper, except in the rarest of coincidences.

The cost and economic data presented in the White Paper appear to have been extracted directly from the underlying documents referenced, are not updated to current dollars and should be revised. Also, similar to other costs and benefits noted in the White Paper, they appear to be based on self-selected reports from Natural Gas Star partners on successful installations of velocity strings and are not likely to reflect the performance/benefits of installation of velocity strings where their application is not based on well-by-well evaluation and selection.

The statement in Table 3.1 that velocity strings are “Considered to be a no emission solution.” is incorrect. It is not uncommon for wells with smaller diameter velocity tubing strings to be vented to aid in liquid unloading. The GHGRP well venting data using Method 1 (which represents a small portion of total reports) for 2011 and 2012 contain multiple data sets where the tubing size selection is <1” although this selection is not always consistent with the average tubing size shown.

i. Section 3.1.1 - Foaming Agents:

The discussion of soap/surfactant use in Table 3.1 is not consistent with the discussion in the narrative and is not correct. The Table 3.1 discussion focus on injection of soap/surfactants omits instances where wells are configured to gravity feed surfactants along with instances where “soap sticks” are simply “dropped” down the casing-tubing annulus. The discussion of how a soap/water solution generates foaming is an oversimplification of the physics involved which are dependent on turbulence for foam generation. In general, the successful use of surfactants is more than the low-tech solution implied by the table.

The Table 3.1 representation of foaming agents as a “no emission solution” is not correct. It is not uncommon for venting to be used in conjunction with soap/surfactant use to unload liquids.

The cost and economic data presented in the White Paper appear to have been extracted directly from the underlying documents referenced, are not updated to current dollars and should be revised. Also, similar to other costs and benefits noted in the White Paper, they appear to be based on self-selected reports from Natural Gas Star partners on successful use of soap/surfactants and are not likely to reflect the performance/benefits of soap/surfactants where their application is not based on well-by-well evaluation and selection.

Charge Question 5

> *Please provide any data or information you are aware of regarding the prevalence of these technologies in the field.*

Data regarding the prevalence of plunger lift installations is presented in the API/ANGA survey report where 36% of the wells reported (21,500 of 59,648 wells) having plunger lifts installed. Projecting this to a national population for 2010 the API/ANGA report estimated about 174,743 wells with plunger lift in 2010.

Data regarding the prevalence of mechanical deliquification (artificial lift) is presented in the API/ ANGA survey report where 13.4% of the wells reported (7,993 wells) having some form of mechanical deliquification installed. Projecting this to a national population for 2010 the API/ANGA result implies about 68,000 wells with mechanical deliquification installed in 2010.

Charge Question 6

> *In general, please comment on the ability of plunger lift systems to perform liquids unloading without any air emissions. Are there situations where plunger lifts have to vent to the atmosphere? Are these instances only due to operator error and malfunction or are there operational situations where it is necessary in order for the plunger lift to effectively remove the liquid buildup from the well tubing?*

Plungers operate by providing a mechanical barrier between the liquid column in a well-bore and the reservoir gas/energy that is used to lift the plunger and liquid load to the surface. Plungers depend on adequate differential pressure to lift liquids and do increase the efficiency of using reservoir energy vs. depending on velocity to drag liquids. A plunger's ability to rise is defined by six physical parameters :

- Weight of the plunger
- Mechanical friction of the plunger against the tubing walls
- Fluid friction against the tubing walls
- Weight of the liquid being lifted
- Surface equipment pressure drop and collection system/surface backpressure
- Formation/reservoir pressure available for lift

The first three parameters have a reasonably consistent and predictable magnitude. The fourth parameter is quite variable. If the total liquid weight increases, the balance between bottom-hole pressure and flowing tubing-head pressure can fall to zero and lose the driving force for the system. At that point operators may remove surface restrictions and gathering-system pressure from the equation by venting the well to re-establish the necessary differential pressure to run the system. Other operators may rely on shut-in periods to build pressure in the near well reservoir. Other operators may install well-site compression to allow the use of mechanical horsepower to remove the backpressure from the process.

With advanced reservoir-energy management and optimized well-liquids unloading management, large reductions in the frequency of well venting and thereby emissions resulting from liquids unloading, from both plunger and non-plunger equipped wells, can likely be made. However, the need to vent will still occur. Even with advanced plunger lift systems and advanced control systems for both plunger lift equipped wells, there will be instances where venting a well to atmosphere is necessary to gain the differential pressure necessary to bring a plunger to surface. This is generally due to periods of greater than normal water loading (height of water column) in the well bore which can be caused by natural variation in reservoir flow or system failures/malfunctions.

As the emission data sources uniformly show, venting of wells equipped with plunger lifts accounts for more emissions overall and on a per-venting-well basis than emissions from venting of wells not equipped with plunger lifts. The counterfactual interpretation of the data, which the ICF/EDF paper does, is purely conjecture and should be noted as such.

Charge Question 7

> *Based on anecdotal experience provided by industry and vendors, the blowdown of a well removes about 15% of the liquid, while a plunger lift removes up to 100% (BP,*

> *2006). Please discuss the efficacy of plunger lifts at removing liquids from wells and the conditions that may limit the efficacy.*

The representation in this question that the BP presentation referenced claims 100% liquid removal (presumably of the column of liquid in the well-bore above the plunger) is not correct. The BP presentation made no representations regarding the percent of liquid (again presumably the column of liquid in the well-bore above the plunger) removal by a plunger.

In practice, plunger lifts are designed with clearance between the plunger and the tubing walls to enable gravity free-fall down a well and minimize plunger friction during travel to the surface. Due to this clearance, some gas leaks upwards past a plunger and some liquid "slips" past the plunger or plates out against the tubing wall and subsequently falls back into the well. The amount of liquid that "slips" or plates out against the tubing walls and subsequently falls back into the well is variable and depends on several factors.

Charge Question 8

> *Please comment on the pros and cons of installing a plunger lift system during initial well construction versus later in the well's life. Are there cost savings associated with installing the plunger lift system during initial well construction?*

There is likely no instance where installation of a plunger lift system during initial well construction would be beneficial. Many wells will never be a candidate for plunger lift use and installation of a plunger lift system would simply be a complete waste of money. Most wells that eventually do experience liquids loading and are candidates for plunger lifts will not reach that point until after many years of free-flowing production. Installing a plunger lift system at initial well construction would unnecessarily decrease capital efficiency. Practically, in the time that a well is free-flowing, it is likely that the well may be worked on 3-5 times, each time it is worked on all of the plunger equipment would be removed to facilitate pulling the tubing. After sitting in a well for many years, it would be rare for components like profile nipples, bumper springs, and lubricators to be in a condition that would allow their re-installation so putting this equipment on new wells assures that it will be discarded long before it could ever be put in service. It is also unlikely that a plunger lift system installed at initial well construction would be functional if and when it was called on to operate after many years of sitting in a well. For high flowing wellhead pressure wells, such as the Marcellus Shale, lubricators for plungers are not available with pressure ratings high enough for application. For high production rate wells, the tubing sizes are larger to accommodate the flow. Tubing plungers for 4.5 inch tubing, which is common in high rate wells, are not available - nor are they needed due to the high flow rates and velocities. Additionally, the plunger equipment in a well can fail and cause problems that would require additional expenditures to correct.

Installing a plunger lift system at the time of initial well construction would also "lock-in" technology at the time of installation. Given the tremendous amount of research, development and focus being applied to deliquification of gas wells and the amount of progress being made this is not advisable.

The concept of installing a plunger lift system at initial well construction indicates a lack of understanding of wells, well life-cycle, liquid loading, and efficient use of resources.

Charge Question 9

> *Please comment on the pros and cons of installing a "smart" automation system as part of a plunger lift system. Do these technologies, in combination with customized control software, improve performance and reduce emissions?*

To the extent that advanced (smart) automation of well operation and liquid loading management improves the management of reservoir energy, such use is likely to reduce, but not eliminate, the need for venting to aid liquid unloading. This can be beneficial for both wells equipped with plunger lifts and wells without plungers installed.

However, these systems are expensive, require customization to the area and reservoir where they are being deployed, and require highly skilled personnel to maintain, calibrate, and operate. As the BP "smart automation" project, referenced in the White Paper, shows these types of installations can be difficult and may take years of concerted effort to achieve the desired outcomes. They are not a "silver bullet" answer to reduce venting for liquid unloading but are another valuable tool to be used as appropriate.

Charge Question 10

> *Please comment on the feasibility of the use of artificial lift systems during liquids unloading operations. Please be specific to the types of wells where artificial lift systems are feasible, as well as what situations or well characteristics discourage the use of artificial lift systems. Are there standard criteria that apply?*

This question indicates a misunderstanding of venting to aid liquid unloading, which is the activity that results in emissions, and the elimination of any benefit of venting when artificial lift is installed. As discussed above, mechanical deliquification (artificial lift) is the addition of energy, in the form of a pump or gas lift, to a well-bore to enable liquid removal. It is employed when the reservoir energy in a well is not sufficient to use other, techniques to aid in liquid removal. Once applied, venting a well provides no benefit and will not occur. However, installation of pumps or gas lift is expensive and the expected production of many marginal wells will not support the investment necessary.

Pumps in gas well deliquification applications struggle to cope with the typically low liquid volumes, variable liquid volumes, and damage caused by cavitation and "gas-locking" of the pumps. Many techniques and approaches are employed in an attempt to deal with this problem with varying degrees of success. Ongoing research and development of gas well deliquification specific approaches and products is making progress on these problems.

Although gas lift is applied to gas well deliquification, it is far less effective on gas wells than when applied to oil wells due to water having little ability to absorb natural gas which serves lighten the specific gravity of the mixed fluid in a well bore. Gas lift typically requires additional compression and piping at the surface which requires either electricity or engines to drive compressors – all of which add emissions, complexity, reliability concerns, and operating costs. Also, gas lift is limited to those reservoir/well combinations where the gas injected down the well will flow up the well-bore and not simply dissipate into the formation.

Beam pumps require a surface power unit and continuous rods from the surface to the bottom-hole plunger pump. While more forgiving of low liquid production volumes than submersible pumps or progressing cavity pumps, beam pumps are not very optimum for deviated well-bores such as those on multi-well pads (done to reduce surface disturbance). In a deviated well-bore, the rods will tend to rub against the tubing/casing and cause wear and failure of either the rods and/or the tubing/casing. Unless electricity is available, the surface power unit must be a gas fired reciprocating engine which adds significant emissions, complexity, reliability concerns, and operating costs.

It is important to understand the distinction between applying a mechanical deliquification technology to a gas well to remove liquids from interfering with gas production and artificial lift in the classic sense of lifting a commercial product, typically oil, to the surface. The economics and economic drivers are entirely different between the two. When the expected production from a gas well cannot support the investment required to enable deliquification, it will reach the end of its economic life and be abandoned. Requiring the installation of mechanical deliquification technology (artificial lift) would cause many marginal U.S. gas wells to be abandoned. This would likely disproportionately impact smaller producers since they typically have portfolios of smaller more marginal wells.

There are no "standard criteria" that apply across reservoirs, wells, and companies.

Charge Question 11

> *The EPA is aware that in areas where the produced gas has a high H2S concentration combustion devices/flares are used during liquids unloading operations to control vented emissions as a safety precaution. However, the EPA is not aware of any instances where combustion devices/flares are used during liquids unloading operations to reduce VOC or methane emissions. Please comment on the feasibility of the use of combustion devices/flares during liquids unloading operations. Please be specific to the types of wells where combustion devices/flares are feasible. Are there operational or technical situations where combustion devices/flares could not be used?*

API is not aware of any instances where flares or other combustion devices are used during liquids unloading operations. In 2012, 58,663 discrete wells were reported into the GHGRP as vented for liquids unloading. Grossing this up, using EPA's estimate of 85% coverage under Subpart W, yields just over 69,000 individual wells vented to unload liquids in 2012. Flaring of gas during liquids unloading would necessitate separation of the liquids from the well stream in a separator or flare knock-out drum. Backpressure, sufficient to unload liquids from the separator to a storage tank, would need to be held against the well/separator which would directly reduce the differential pressure gained by routing to atmosphere and perhaps inhibit unloading. Due to the potential flow rate and Btu demand, flares would need to be dedicated to liquids unloading and be moderate size

(~20 MMBtu/hr) rated. Liquids unloading flares would need either continuous pilots (for infrequent use) or electronic igniters powered by solar in most instances. Also, well-sites would need to be "re-piped" to route from the separator to the dedicated well unloading flare. Besides the technical difficulties dealing with the intermittent and surging flow characteristic of venting for liquids unloading, the changing velocities during an unloading and the problems of ensuring ignition for a sporadically used flare, the cost would be prohibitive. Multiplying the estimated total installed cost of $100k per flare times the number of wells vented for liquid unloading in 2012, the cost would easily be *billions* of dollars. There are much more cost effective methodologies to reduce liquids unloading without the emissions and visual impact associated with flaring.

Combustors on H_2S wells are truly a special case. Hydrogen sulfide presents an acute safety risk both to employees and to the general public. Understanding and designing for that risk is part of the economic evaluation made prior to producing the well. Combustors on these wells regularly require electricity to drive blowers to ensure that the combustion process is stoichiometric and unburned process gas is prevented to the maximum extent possible. Igniters/pilots that are robust and redundant technologies are provided. In short these devices are very expensive to acquire and operate. Requirements for this technology on sweet-gas wells would make the vent/plug decision much easier and many wells with considerable recoverable gas in place would be abandoned rather than installing flare/combustion technology.

Charge Question 12

> *Given that liquids unloading may only be required intermittently at many wells, is the use of a mobile combustion device/flare feasible and potentially less costly than a permanent combustion device/flare?*

It is very unlikely that portable flare equipment, which tends to be more expensive on a unit basis than stationary flares, would be feasible for use with respect to venting for liquids unloading. Moving a flare to a location, hooking it up to a vent line, testing the integrity of the system, and then ensuring a pilot light each time a well was to be vented would take considerable time and cost. Given the sheer number of wells that vent for liquids unloading, about 69,000 in 2012 based on the GHGRP data, coupled with the number of venting instances, 4,524,802 venting events for Method 1 reported into the GHGRP plus the yet to be reported instances for Methods 2 & 3, the costs and logistics to use this approach would far outweigh any benefits.

Charge Question 13

> *Given that there are multiple technologies, including plunger lifts, downhole pumps and velocity tubing that are more effective at removing liquids from the well tubing than blowdowns, why do owners and operators of wells choose to perform blowdowns instead of employing one of these technologies? Are there technical reasons other than cost that preclude the use of these technologies at certain wells?*

The disparity between reports into the GHGRP, discussed above, indicate that how a company or operation handles liquid unloading and specifically the philosophy regarding management of reservoir energy with respect to well-bore liquid management has a very large effect on use of venting as part of well-bore liquid management.

Some operators choose to put production packers above the productive formation. These packers limit deliquification options to vent cycles or velocity strings since they preclude plungers, mechanical pumping, or the use of soap/surfactants.

At this time, deliquification of horizontal wells is a work in progress with considerable research ongoing to develop or improve technologies. When the flow rates decline to the point that there is inadequate velocity in the wellbore tubulars to allow the gas to lift the liquid there are examples of horizontal wells being placed on vent cycles simply because there is not an option.

Charge Question 14

> *Are there ongoing or planned studies that will substantially improve the current understanding of VOC and methane emissions from liquids unloading events and available options for increased product recovery and emissions reductions? The EPA is aware of an additional stage of the Allen et al. study to be completed in partnership with the EDF and other partners that will directly meter the emissions from liquids unloading events. However, the EPA is not aware of any other ongoing or planned studies addressing this source of emissions.*

Other than the Phase 2 UT/EDF study mentioned, no studies of liquids unloading are known to be currently underway. However, data reported into the GHGRP in March of 2015 for the 2014 emission year will include additional information related to venting (previously deferred) that will provide significantly better understanding of venting for liquid unloading. Pending changes to Subpart W of the GHGRP will require reporting of additional data parameters in 2016 for the 2015 emission year, which will also aid in understanding of venting for liquid unloading.

C. Conclusion

As the GHGRP and API/ANGA data illustrate, venting for liquids unloading is a problem mostly driven by a relatively small number of operators and a relatively small subset of wells. This strongly suggests that a targeted intervention is appropriate to address this issue.

Since the frequent use of venting is restricted to a small number of operators and the GHGRP data makes this information public, operators that represent the majority of venting events are actively working to reduce/eliminate venting in their operations to avoid the public exposure in future reports. This alone is likely to significantly reduce the frequency of venting to aid liquids unloading and hence emissions. The assertion in the White Paper that installation of plunger lift systems is an emission (venting) control technique is not correct, not supported by the emission data, and not underpinned by a logical or technical analysis in the White Paper. It is absolutely true that plunger lifts are a valuable, effective and commonly used methodology/tool to assist in managing well-bore liquid loading. Plunger lifts do increase the efficiency of liquids removal from wells by the reservoir energy and hence do help maintain or increase production.

However, the efficacy of plunger lifts in reducing venting of wells and emissions is completely dependent on how they are operated. As the API/ANGA survey report, the GHGRP data, the U.S. Emission Inventory, and the ICF/EDF report shows: venting wells with plungers have higher emissions per well than venting wells without plunger lifts. From an emission perspective, wells with plunger lift systems accounted for about 72% of the GHGRP reported emissions from well venting for liquids unloading. T**he general efficacy of plunger lift systems as an emission control measure is clearly not supported by the data**. However, with advanced well liquids unloading management (i.e. management of reservoir energy), large reductions in the frequency of well venting and thereby emissions resulting from liquids unloading, from both plunger and non-plunger equipped wells, can likely be made.

API – March 27, 2014

Liquids Unloading

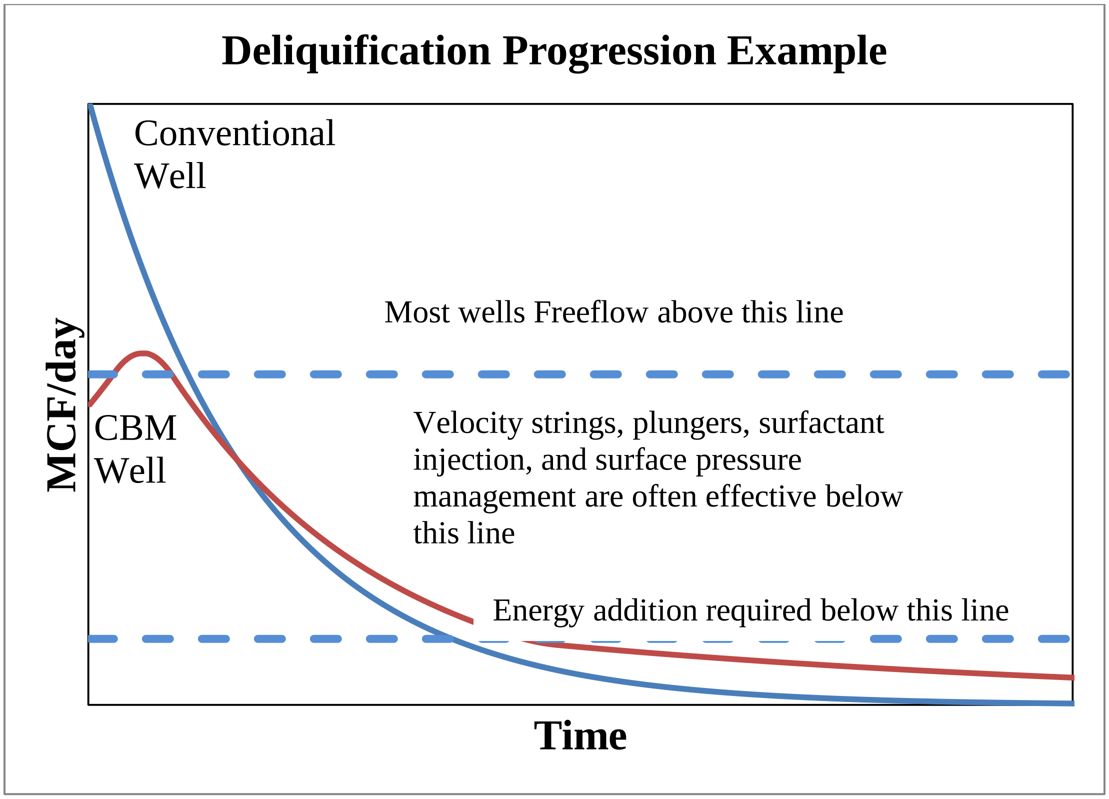
Well-bore Deliquification (Liquids Unloading) Background

Well-venting to unload liquids can be a significant source of hydrocarbon pollutant emissions and there are technologies and techniques in use and available to significantly reduce, but not eliminate, venting of wells to assist in deliquification. Deliquification of gas wells is a highly complex and technical subject with many approaches and technologies in use and venting of wells is one technique, often used in combination with other techniques that depend on reservoir pressure - such as plunger lifts, used to assist unloading. Well deliquification is a fundamental challenge for continued production from the majority of US gas wells and the proportion is expected to grow with new growth concentrated in non-traditional gas reservoirs such as shales, coal-beds, and tight-gas sands which are susceptible to liquid loading. Managing wellbore liquids loading is a primary focus for production engineers and operations teams. A very large amount of industry focus, research, and attention is applied to gas-well deliquification with innovation and research continually underway. For example, the 12th Annual Gas Well Deliquification Workshop was held in February 2014 in Denver, Colorado was attended by over 500 representatives of dozens of upstream producers. This workshop series, along with a portfolio of other venues dedicated to well deliquification and artificial lift, is organized by the Artificial Lift Research and Development Council (ALRDC), and the Southwestern Petroleum Short Course (SWPSC). This research and work is both optimizing and improving existing techniques along with developing entirely new types of systems. The flexibility to pilot some of these ideas/developments must be preserved – even if they ultimately do not succeed.

Liquid loading of well-bores occurs when the gas production-rate (velocity) up the well-bore is not sufficient to carry liquids up the well-bore. When a vertical liquid column builds up in the well-bore, the weight of the column puts back-pressure on the producing formation and the production rate declines to the point where the well can quit flowing. According to the Energy Information Administration's 2009 "Distribution of Wells by Production Rate Bracket" some 338,056 (73%) wells out of a total gas well inventory of 461,388 gas wells produce 90 mcf of gas (15 BOE) or less per day (http://www.eia.doe.gov/pub/oil_gas/petrosystem/us_table.html) . These low rate wells are either impaired by liquids accumulation or are using some deliquification method to produce.

Wells and reservoirs follow a continuum of flow regimes in their economic life as the reservoir depletes, production goes down, well-bore (tubing) velocity goes down, and liquid loading begins to occur in the well-bore. In the early stage of a well's life many (but by no means all) wells can flow freely and with sufficient velocity to avoid liquid loading problems. As the reservoir energy depletes and the production-rate declines, a well will reach the stage where liquid-loading begins to be a problem and one of a portfolio of technologies or techniques will be used to help lift liquids using the reservoir's energy. As a well continues to produce and the reservoir energy declines further, a well will reach the stage where the reservoir's energy is not sufficient to lift liquids and artificial lift energy, in the form of pumps, gas lift, etc., will have to be added to continue producing. When the expected production from a well cannot support the investment required to enable deliquification, it will reach the end of its economic life and be abandoned.

The following figure shows a generalized well life-cycle curve with these different stages of a wells life illustrated.



To combat this normal well/reservoir depletion and assist liquid lift a number of techniques are used – dependent on the well configuration, reservoir properties, well depth, and surface equipment and collection system.

Techniques that rely on the reservoir energy are:

- The tubing in a well may be changed to smaller diameter "velocity strings" which provide for higher velocity at any given flow rate and provide higher liquid lift capabilities. There is a decreasing benefit from smaller diameter velocity strings due to flowing friction buildup in smaller diameter tubing.
- Soap injection may be used to "foam" the liquids to reduce the unit density and enable liquids lifting.
- Wells may be put on a shut-in cycle to allow pressure/energy build-up of the reservoir near the well bore which equals higher production rates/velocity (temporary) and better liquids lifting.
- A plunger lift may be installed in a well. This is generally coupled with a shut-in cycle to build enough pressure under the plunger to lift it along with the liquid column.
- Venting a well may be used in conjunction with any of these techniques to create additional differential pressure/energy and aid unloading of liquids.

Techniques where energy is added to the well:

- Mechanical pumps are selected when rate of liquid accumulation is too high for plungers to operate or reservoir pressure is too low for plungers to operate without excessive shut-in time to build up reservoir pressure.
- Gas lift which raises tubing velocity to lift liquids by injecting gas down the tubing-casing annulus.
- Compression which lowers the surface pressure creating more differential for flow and increasing velocity by lowering pressure.
- Combinations of above approaches such as foaming, gas lift, and compression

The choice of what technique to employ is based on well-by-well and reservoir-by-reservoir analysis and is one of the primary jobs of the production engineering teams. For a typical well, as it moves through the depletion continuum, a series of techniques will be employed. The decision on technology-selection requires a thorough understanding of the conditions that a reservoir is flowing into, the reservoir's sensitivity to backpressure and the volumes and pressures that the deliquification technology must handle, and costs/benefits of applying the technology. Operators must have the flexibility to choose the most appropriate and cost effective approach for each individual well/reservoir/age/production combination and the regulatory certainty to underpin continued investment.

An excellent overview of this subject is Gas Well Deliquification, Second Edition, by Dr. James F. Lea, Dr. Henry V. Nickens, and Mr. Mike R. Wells (Gulf Publishing, 2008, ISBN 978-0-7506.8280-0). This 588 page book does a good job of explaining the basis for choosing among the various technologies, but it does not presume a one-size-fits-all solution.

Well Venting to Aid Liquids Unloading

The production rate of a well, consequent velocity up the well-bore, and, hence, the ability to lift liquids is mostly a function of the differential pressure between the reservoir and the flow-line/collection system and the reservoir's sensitivity to backpressure. In order to flow, the total reservoir pressure must be greater than the total resistance to flow. This resistance is comprised of fluid friction and fluid interference across the reservoir; the flowing friction up the well-bore; the weight of the vertical fluid column in the well-bore; surface equipment and piping pressure losses; and the collection system/flow-line back-pressure. Opening a well-bore to atmospheric pressure (venting a well) removes the effect of the surface equipment/piping pressure-loss and the back pressure from the collection line and increases differential pressure to increase flow rates and velocities, which may enable the well to lift the liquid from the well-bore (unload the well). Venting of wells has been a common practice in low rate gas well deliquification for decades and is not restricted to wells without deliquification assist technologies, such as plunger lifts, in place. As the API/ANGA report and the GHGRP data show, venting of wells to aid liquids unloading occurs in both plunger equipped wells and non-plunger equipped wells with plunger equipped wells having higher reported emissions overall.

Minimizing Venting to Assist Liquids Unloading

As discussed above, there are various reservoir-driven techniques operators use in wells experiencing liquids loading to assist in deliquification, which also helps reduce the need for venting. Each of these may be the best solution for a particular portion of the life of a reservoir. **It is a misconception that plunger-lift systems are the single emission control action for wells where venting for liquids unloading occurs.** This misconception is further exacerbated by a lack of understanding, even among those purporting plunger lift systems as *the* solution to liquids unloading, of liquids loading or plunger lift systems and their appropriate uses, limitations, and efficacy. Plungers work by providing a mechanical barrier between a small volume of water and the gas that is used to transport it up the well-bore. The mechanical barrier isolates the gas from the liquids, prevents gas from moving up through the liquids hence making better use of the gas energy, and helps prevent liquids from falling back into the well-bore. If the gas could flow faster, then that mechanical barrier would not be necessary or helpful. Plunger capacity is limited by well depth, differential between reservoir pressure/surface pressure, and the gas/liquid ratio that the well produces. Even plunger lifted wells reach a point where they lack the reservoir pressure to run a plunger against backpressure with adequate frequency to lift the liquid present. At that point the operator has the choice of replacing the plunger with a lift method that adds energy to the system or plugging the well. Operators analyze these wells and have to make the decision to spend capital and operating expense on a pump versus drilling a new well.

It also appears that EPA holds some misunderstanding of plunger lift. Although plungers are among the most common tools used in middle stage deliquification, there is a misconception that plungers eliminate the need to vent to atmosphere. In many cases, wells are vented to atmosphere to generate the differential pressure necessary to lift the plunger and liquid column up the well-bore. While this can be controlled and minimized, it cannot be eliminated.

- One primary study/project that is often highlighted from the Natural Gas Star program is the BP "smart automation" well bore venting control system in the San Juan basin. What is generally misunderstood (or simply not acknowledged) is that about half of the wells which were venting (around 4.2 BCF of gas per year) were plunger equipped and were vented in order to generate the energy necessary to lift the plunger and liquid column. The fundamental nature of this project has also been mischaracterized as a project to install plunger lift systems to mitigate venting. The *actual* nature and success of the project was to optimize the shut-in times on individual wells and plunger cycle timing on wells with plungers through the use of automation that learned the performance of each well and then optimized the cycle parameters for that well – i.e. "smart automation". This was and is a project about managing reservoir energy not about installing or running plunger lift systems. The basic concept is: "The reservoir does not quit working when a well is shut-in".
    - The fact that it took about 6 years to fully develop the system and achieve 90% + venting reduction is also often ignored. It is technically and operationally very difficult.
- Plungers are not universally applicable to well-bores. For example, unless remedial action is taken, a plunger can't be used in a well-bore with changing tubing sizes, defects or buildups of scale or in coil tubing which has an "internal upset" weld seam. Plungers can only be run where the inside of the well-bore is reasonably smooth and in reasonably good condition. They also do not work well in highly deviated directional (S-shaped – typical for multi-well pads) or horizontal well-bores.
- Although casing plungers are available for wells without tubing, they have had significant reliability problems and it is also difficult to control the velocity up the well-bore to avoid high velocities which have blown the top off of well-heads resulting in uncontrolled release of significant quantities of gas.
- Once a well/reservoir declines sufficiently, plungers will no longer work and energy must be added to the well-bore or the well abandoned. This is an economics decision.

Studies and Data Sources

- API believes the only recent data/studies with a broad data set are the API/ANGA survey results and report and the GHGRP reported data.
- Care needs to be taken in use of the GHGRP data. For example, one company in one basin (one reporter/facility combination) accounts for about 37% of the industry wide methane emissions from liquids unloading. Any broad national "emission factor" should either exclude this data set or weight it according to the number of wells producing and/or venting.
- The UT/EDF study measured emissions from about 9 liquid unloading events but all were shale wells and hence do not represent the cross section of well/reservoir types. In addition, the supplemental information indicated that the researchers "triggered" an unloading event in some instances to enable measurement. If correct, the flow profile would not be equivalent to a well with a liquids column in the well-bore which inhibited flow and triggered venting to the atmosphere.
- Phase 2 of the UT/EDF study is purported to include measurement of a larger number of liquid unloading events from a cross section of well/reservoir types. The phase 2 report is expected to be published later in 2014.
- The annual U.S. Inventory of Greenhouse Gas Sources and Sinks estimate of emissions from liquids unloading also needs to be used with an abundance of caution. The radical variation in the estimated methane from liquids unloading; from 185.57 Gg in 2008 up to 4,554.42 Gg in 2009 (~2,354% increase) and then down to 249 Gg in 2011 (98% decrease) amply illustrates the uncertainty of the Inventory as a data source.
- The Natural Gas Star presentations and documents need to be fully understood, including the limitations of conditions, physical and operational, to their applicability – many/most are not universally applicable and this is often ignored. Also, many of the Natural Gas Star partner reported opportunities have been characterized incorrectly in some of the documentation – such as the BP project discussed above.

Options for Mitigating Venting for Liquids Unloading

Options dependent on reservoir energy

- Automated control of shut-in cycles and plunger runs (where equipped) to optimize building of formation/reservoir energy – used with both plunger and non-plunger wells. This will only work where a radial pressure gradient from low to higher exists in the reservoir as distance from the wellbore increases – which is typical for tight sands, shales, and some other formation types. The automation algorithms must be customized for each area (reservoir and well combinations) although the basis code, physics and approach are the same.

- A combination of flow measurement on the tubing and valve control on the tubing/casing annulus to allow the use of the tubing flow to manage liquid production while allowing well capacity in excess of the amount required for unloading to be produced up the tubing/casing annulus.
- Install plunger lifts along with appropriate control system. Plungers depend on formation/reservoir energy to lift liquids and cannot operate when energy declines beyond that necessary to lift liquids. Using automated control of shut-in cycles (above) will extend the period where plunger lift systems are effective without regular venting to assist plunger recovery.
    - Even with advanced plunger lift systems and control systems there will be instances where venting a well to atmosphere is necessary to gain the differential pressure necessary to bring a plunger to surface. This is generally due to periods of greater than normal water loading (height of water column) in the well bore which can be caused by natural variation in reservoir flow, or system failures/malfunctions.
- Velocity (smaller diameter) tubing strings to increase velocity and liquid lift. However, there is a trade-off between tubing diameter and flowing friction back-pressure. As tubing diameter decreases, flowing friction increases which decreases differential pressure and hence flow rate/velocity. At small tubing diameters, the flowing friction decreases velocity more than the restricted flow area increases velocity. Velocity strings depend on formation/reservoir pressure to lift liquids.
- Soap/surfactant sticks or injection. These work by increasing the surface area/weight ratio of water hence increasing the ability of a certain velocity to lift liquids. Soap sticks and soap/surfactant injection are generally considered a stop-gap solution to liquids loading because balancing the amount of soap, the ability to activate the soap load, and the ability to deal with the formation damage that soap can cause generally shortens the effective period that this technique is adequate. Wells producing a high proportion of condensate or oil do not foam adequately and there is a potential to form emulsions which may prevent flow or need additional surface treatment. When using batch/soap sticks, the well will be shut-in to enable pressure build-up and chemical mixing. Then the well may be blown down to start flow again. This may reduce the overall blow-downs but will not eliminate them. Continuous injection needs to get the amount of chemical just right; too much = less production and foam on surface; too little = less production. A limitation of any surfactant is the chemical make-up of the liquid that must be lifted. Some wells load with water, others may load with condensed hydrocarbon liquids (condensate). The surfactant must be compatible with the liquids in the well, and condensate is more difficult to treat. As

mentioned with other techniques, there is no “one size fits all” solution. Different foaming agents can have different effectiveness and the efficacy for an individual well will vary.

Options that add energy

- The economic life of a gas well is often defined by the ability to economically support installing deliquification methods. If a well cannot economically support the cost to add energy to a well for lifting liquids, it will be plugged and abandoned.
- Install additional surface compression to lower back-pressure against the well.
- Typical approaches to mechanical deliquification are a submersible pump, a beam pump (nodding donkey), and gas lift.
    - Submersible pumps are better suited to oil wells with high liquid volumes and they struggle with the low amount of liquids in a depleted gas well. If sufficient liquids are not produced and a “pump-off” controller does not work (common), they will burn out. Submersible pumps require a fairly high-voltage (440 V) electricity source at each well which is not common. Electrical cable must be run to the bottom-hole pump location to power the pump.
    - Beam pumps require a surface power unit and continuous rods from the surface to the bottom-hole plunger pump. While more forgiving of low liquid production volumes than submersible pumps, beam pumps are not very optimum for deviated well-bores such as those on multi-well pads (done to reduce surface disturbance). In a deviated well-bore, the rods will tend to rub against the tubing/casing and cause wear and failure of either the rods and/or the tubing/casing. Unless electricity is available, the surface power unit must be a gas fired reciprocating engine which adds significant emissions, complexity, reliability concerns, and operating costs.
    - Gas lift requires a higher pressure gas supply to “inject” down the casing-to-tubing annulus in order to increase the flow up the tubing thereby increasing the velocity and capacity to lift liquids. Gas lift typically requires additional compression and piping at the surface which requires either electricity to drive compressors or engines to drive compressors – all of which add emissions, complexity, reliability concerns, and operating costs. Also, gas lift is limited to those reservoir/well combinations where the gas injected down the well will flow up the well-bore and not simply dissipate into the formation.
    - For further information regarding gas well liquids loading, gas well liquids unloading, and artificial lift please see the Artificial Lift R&D Council web-site at http://www.alrdc.com/production/

EPA Questions and Responses

EPA Questions: What is the feasibility of the use of flares during liquids unloading operations? Are there operational or technical situations where flares could not be used?

API is not aware of any instances where flares or other combustion devices are used during liquids unloading operations. In 2012, 58,663 discrete wells were reported into the GHGRP as vented for liquids unloading. Grossing this up, using EPA's estimate of 85% coverage under Subpart W, yields just over 69,000 individual wells vented to unload liquids in 2012. Flaring of gas during liquids unloading would necessitate separation of the liquids from the well stream in a separator or flare knock-out drum. Backpressure sufficient to unload liquids from the separator to a storage tank would need to be held against the well/separator which would directly reduce the differential pressure gained by routing to atmosphere and perhaps inhibit unloading. Due to the potential flow rate and Btu demand, flares would need to be dedicated to liquids unloading and be moderate size (~20 MMBtu/hr) rated. Liquids unloading flares would need either continuous pilots (for infrequent use) or electronic igniters powered by solar in most instances. Also, well-sites would need to be "re-piped" to route from the separator to the dedicated well unloading flare. Besides the technical difficulties dealing with the intermittent and surging flow characteristic of venting for liquids unloading, the changing velocities during an unloading and the problems of ensuring ignition for a sporadically used flare, the cost would be prohibitive. Multiplying the estimated total installed cost of $100k per flare times the number of wells vented for liquid unloading in 2012, the cost would easily be *billions* of dollars. There are much more cost effective methodologies to reduce liquids unloading without the emissions and visual impact associated with flaring.

EPA Question: What is the feasibility of the use of artificial lift systems during liquids unloading operations?

This question indicates a somewhat fundamental misunderstanding of well liquids management. Artificial Lift, generally considered to be downhole pumps or gas-lift, eliminates the need to unload liquids due to the energy added directly to the well-bore. A pump or gas-lift is installed on a well when it can no longer unload liquids using the reservoir's pressure – but only if the expected production can support the additional capital and operating expense. Requiring early application of "artificial lift" would shorten the economic life of many marginal wells. This would tend to differentially impact small operators due to their tendency to hold portfolios of marginal wells.

EPA Question: When is it infeasible to use a plunger lift system?

Wells with sufficient flow and velocity do not have liquids loading problems and there is no reason to even consider using a plunger lift system. Installing a plunger lift system in a well that does not have liquid loading problems is a waste of money. When a well does encounter liquids loading problems and a plunger lift is judged to be the best option, there are some limitations on when plunger lifts can be run in a well. Plunger lifts cannot be run in wells with variable tubing sizes, defects or scale build-up in the tubing, or in wells with coil-tubing that has an internally-upset weld seam. They can only be run in wells with reasonably smooth tubing. Plungers do not work well in highly deviated directional (S-shaped – typical for multi-well pads) wells. In a horizontal well, plungers will only run in the vertical portion of the well-bore. For wells without tubing, casing plungers are available but have had significant reliability problems and have experienced difficulties controlling the velocity up the well-bore to avoid high velocities which have blown the top off of well-heads resulting in the uncontrolled release of significant quantities of gas. Once a well/reservoir declines sufficiently, plungers will no longer work and energy must be added to the well-bore or the well abandoned. Again, this is an economics decision.

EPA Questions: Are there situations where plunger lifts have to vent to the atmosphere? Are these instances only due to operator error and malfunction or are there operational situations where venting is necessary in order for the plunger lift to effectively remove the liquid buildup from the well tubing?

Wells with plunger lift systems comprised ~55% of the more than 58,000 wells reported as venting for liquids unloading into the GHGRP for 2012. From an emission perspective, wells with plunger lift systems accounted for about 72% of the emissions from well venting for liquids unloading. The GHGRP reported data is broadly equivalent to that reported from the API/ANGA survey. With the API/ANGA survey outcome of about 36% of the well population being equipped with plunger lift systems yet responsible for over 50% of the venting wells and 70% of the emissions, **the efficacy of plunger lift systems as an emission control measure is clearly not supported by the data**. Although, with advanced well liquids unloading management, large reductions in the frequency of well venting and thereby emissions resulting from liquids unloading, from both plunger and non-plunger equipped wells, can likely be made. However, the need to vent will still occur. Even with advanced plunger lift systems and advanced control systems for both plunger lift and non-plunger lift equipped wells, there will be instances where venting a well to atmosphere is necessary to gain the differential pressure necessary to bring a plunger to surface. This is generally due to periods of greater than normal water loading (height of water column) in the well bore which can be caused by natural variation in reservoir flow or system failures/malfunctions.

EPA Question: It is EPA's understanding that liquids loading becomes more likely as wells age due to declining well pressure.

See well lifecycle discussion in the background section above.

EPA Question: Is liquids loading only a problem for older wells or can wells develop liquids loading problems relatively quickly in certain situations?

Liquid loading is a function of the gas flow-rate from a well and the amount of water/liquid it produces which is somewhat independent of age. Older wells do tend to be lower producers due to being located in fields/reservoirs that have been produced for a long period and are partially depleted. However, not all old wells have liquid loading problems and not all new wells are immune from liquid loading problems.

EPA Question: Are certain wells more prone to developing liquids loading problems such as hydraulically fractured wells versus conventional wells?

The tendency of a well to have liquid loading problems is caused by a combination of lower gas flow rate and liquids production. Whether a well has been hydraulically fractured or not is immaterial. Because hydraulic fracturing tends to increase production, hydraulic fractured wells should tend to have fewer liquids loading problems than an equivalent non-fractured well. Due to their production profile, some coal bed wells tend to have liquids loading problems early in their life.

<u>ICF/EDF Mitigation Paper Commentary – Liquids Loading</u>

The ICF paper recommends plunger lift systems as the sole technology to reduce venting for liquids unloading and the consequent emissions. Although other techniques of managing well-bore liquids were briefly discussed, only installation of plunger lift systems was analyzed. Throughout the paper, the authors make a series of unsupported assertions and assumptions to arrive at their recommendation. Additionally, there are several instances where the authors' statements clearly indicate a limited understanding of liquids loading or the techniques used to manage liquids loading in wells. Some examples:

- *Plunger lifts are devices that fit into the well bore and use the gas pressure to bring liquids to the surface more efficiently while controlling and limiting the amount of venting (Figure 3 7).*

  - The assertion that plunger lift systems control and limit the amount of venting is not supported by the facts that plunger equipped wells account for the majority of both venting wells and emissions from venting for liquids unloading. Although a properly managed plunger lift system will help manage liquids unloading in a well, the impact on emissions will be dependent on the well and reservoir conditions along with how the plunger lift is setup based on these conditions.
- *If there is insufficient pressure to direct the gas to the sales line and the gas must be vented, the emissions can still be reduced by 90% compared to uncontrolled venting. … Plunger lifts are a relatively low cost option and can be implemented in a relatively simple manual control method or more complex automated installations. … Gas STAR Partners report reductions of venting emissions of 90% for plunger lifts that do not go to the sales line.*
  - The statement that simply installing a plunger lift in a well will reduce emissions by 90% appears to be anecdotal as the authors do not provide any source or reference for the information despite providing the source/reference for some of the other information in the report. The authors' implication that this level of emission reduction can be achieved absent appropriate management of the reservoir energy is simply unfounded.
- *While it seems counterintuitive that wells with plunger lifts that vent would be emitting more than those without plunger lifts, ICF interprets this information to indicate that most of the wells with the largest venting emissions have already installed plunger lifts while most of the remaining wells are venting infrequently or venting small volumes that do not justify the cost of installing plunger lifts.*
  - This "interpretation" by the authors is completely baseless and not correct. Plunger lift systems are installed in wells to assist with management of liquids loading and enable production - not to reduce emissions. The intent of plunger lift systems is to maintain production, not avoidance of emissions or recovery of emissions. This shows the authors' lack of understanding of liquids loading, management of liquids loading, and the industry's reasons for management of liquids loading.
- *Approaches to plunger lift operation range from ad hoc manual operation, to fixed mechanical timers, to programmable "fuzzy logic" automated controllers. Specific data on the potential reductions from optimized plunger lift operation is not available but it is clear from industry experience that an integrated program of training, technology, and automation can improve the performance of plunger lifts for both productivity and emission reductions.*
  - This statement by the authors ignores the BP "smart automation" project, discussed above, which is focused on the impact (>90% reduction) that optimized management of formation energy on a well-by-well basis can have on emissions,

presented at Natural Gas Star conferences numerous times, and well known to at least one of the ICF authors. At worst, this indicates the authors bias to select information and make assertions that supports a desired outcome and not include information and data that conflicts with their pre-determined goal. At best, it indicates a very cavalier approach to the complex subject of liquids loading which is central to keeping many of the US gas wells producing and which is the focus of ongoing and substantial industry effort and research.

It is not clear what population of venting wells ICF used in their analysis of the economics of installing plunger lift systems. In the body of the report, the authors note about 127,000 wells vented for liquids unloading reported into the GHGRP for 2012. In appendix B, the authors note 69,054 wells reported into the GHGRP as the average for 2011 and 2012. The latter number agrees with API's analysis of the GHGRP data for liquids unloading which shows 69,525 and 58,633 wells vented for liquids unloading in 2011 and 2012, respectively.

Overall, the ICF/EDF report recommendation of a single technology, plunger lift systems, as a solution to reducing liquids unloading emissions widely misses the mark. While significant reductions in emissions from venting wells for unloading liquids, in both plunger equipped and non-plunger equipped wells, are possible using cost-effective techniques, recommending a *single* approach is not appropriate. An integrated approach, choosing between all of the tools available, in a manner appropriate for the well and reservoir – after engineering analysis, and including management of reservoir energy will be necessary to achieve significant reductions.

Recommended Charge Questions for Peer Reviewers

1. Do the data sources and studies that the paper relies upon appear credible and complete?
2. Was sufficient QA/QC conducted with regard to the data sources and studies that the paper relies on to determine their applicability and validity?
3. Are the conclusions reached by the authors supported by the information and data that was relied upon?
4. Are assertions made in the paper supported by the underlying facts and data?
5. Are assumptions made in the paper clearly noted? Do these assumptions seem valid and balanced?
6. Does the paper reflect an understanding of the complexity of liquids loading in gas wells and the technologies and techniques used by industry at appropriate points in a well's life-cycle to manage liquids loading?
7. Does the paper reflect an understanding of the fundamental nature of liquid loading management to the continued ability to produce the majority of the onshore US gas wells?

8. Does the paper adequately discuss the constraints for use of plunger lift systems and the fact that venting of wells equipped with plunger lift systems accounts for greater emissions in the GHGRP data and the API/ANGA report?
9. Does the paper present a realistic evaluation of actual emission reduction potential from regulation of venting for liquids unloading?

Attachment E

Comments on the Benefit-Cost Analysis in EPA's Regulatory Impact Analysis

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1.0 INTRODUCTION

The EPA has prepared a Regulatory Impact Analysis (RIA) of the proposed New Source Performance Standard (NSPS) Subpart OOOOa rules for reducing methane emissions at newly constructed, reconstructed, and modified oil and gas facilities. RIAs are required for rules that will have an annual effect on the economy in excess of $100 million. Based on Executive Orders 12866 and 13563, the EPA is required to use the best available scientific and economic information to quantify the benefits and costs of proposed rules. According to the EPA, the rigorous evaluation of benefits and costs has been a key component of its rulemaking process for decades.

The monetary benefits of the proposed rule are estimated using an estimate of the social cost of methane (SC-CH_4), which has been derived from the approach the United States Government (USG) uses for estimating the social cost of carbon (SCC). The EPA believes that the rules may also improve air quality and reduce health expenditures from exposure to hazardous air pollutants (HAPs), ozone, and particulate matter (PM); however, the EPA states that there are too many difficulties in modeling these benefits and chooses to measure potential benefits only from climate change via the SC-CH_4.

Annualized engineering costs are estimated for each source based on capital costs, one-time labor costs, and on-going annual costs. EPA projects both the total costs and total benefits for the first year the full rule is in effect (2020) and for 2025. The net benefits in these years are the difference between the total benefits and costs, measured in 2012 dollars.

For the EPA's preferred option (Option 2), the RIA estimates that the annual compliance costs of the proposed rule will range from $320 to $420 million by 2025, measured in 2012 dollars. It also concludes the annual benefits will be between $460 and $550 million (using a three percent discount rate). Based on these estimates, EPA concludes that the proposed rule has positive net benefits (i.e., benefits greater than costs); however we note that the difference is marginal.

ERM reviewed the assumptions, calculations and analysis used in the RIA to develop the cost and benefit estimates on behalf of API. This review shows that there are significant problems with the cost and benefit estimates contained in the RIA and with the treatment of uncertainty. Specifically, our review finds that:

- The RIA omits key cost categories and relies on inaccurate cost and emission information, which results in an underestimate of total costs and an overestimate of the emission reductions.

- The RIA does not provide adequate breakdowns of benefits and costs by source, which obscures important information about the cost effectiveness of the rule.
- The SC-CH_4 has inherited all of the problems that plague the social cost of carbon estimates, and the EPA's own peer-review of the SC-CH_4 does not demonstrate that it is economically and scientifically defensible.
- The uncertainty surrounding the benefits and costs is not adequately reflected in the RIA, which does not comply with EPA guidelines for conducting benefit–cost analysis.
- The RIA does not report the net benefits to the United States as required by Office of Management of the Budget (OMB) , only global net benefits.

Overall, ERM concludes that the proposed rule has costs that are significantly greater than the benefits after the corrections are made. Specifically:

1. After correcting for problems with the EPA cost estimates and emission reductions, the point estimate for total costs is $831 million and annual net benefits is -$452 million in 2025 (i.e., costs significantly greater than benefits).
2. The most significant source affected by the revisions is fugitive emissions from well sites, where the net benefits are -$405 million in 2025.
3. After formally accounting for the uncertainty, we estimate global net benefits will range from -$0.92 and $0.17 billion. There is nearly a 90 percent probability that the actual net benefits will be less than the EPA net benefit estimates. There is an 82 probability that net benefits will be negative.
4. Expected annual net benefits for the U.S. will range from will range from -$1.07 billion to -$0.56 billion in 2025.

The remainder of this introduction (Section 1) provides an overview of these findings. Section 2 provides a detailed discussion of the cost analysis, Section 3 discusses the social cost of methane estimates, and Section 4 describes the impact of uncertainty on the analysis.

1.1 OVERVIEW OF ISSUES WITH EPA'S COST AND EMISSION REDUCTION ESTIMATES

Table 1-1 summarizes the source-specific estimates for the 2025 benefits and costs using EPA numbers compared with revised and corrected estimates developed by ERM. While EPA does not provide a breakdown of the benefit-cost analysis in the RIA by regulated source and industry sector, ERM re-created the source-specific estimates based on the input data provided in Tables 3-16 and 4-3 of the RIA, and supporting technical documentation provided by EPA. Evaluating the source-specific estimates is critical to evaluating overall value of the rule. For example, Resources for the future

(RFF) recently conducted a retrospective analysis of RIAs and found that analyses based on average costs and/or benefits will often obscure important differences in impacts across the groups affected by the regulation. (Morgenstern 2015).[1] The heterogeneity of net benefits across sources is clearly evident in this RIA and affects the cost-effectiveness of the rule.

For completeness, Table 1-1 shows all of the sources and sectors included in the RIA. However, this review focuses only on well completions, fugitive emissions from oil and gas wells and pneumatic pumps at well sites. Combined, these sources and sectors account for approximately 80 percent of EPA's estimated methane gas emission reductions and over 90 percent of EPA's estimated costs.

The first set of columns in Table 1-1 show the benefits, costs and net benefits based on EPA assumptions and calculations. Within the RIA, the EPA does not provide annualized benefits for reducing emissions from fugitives at both oil and gas well sites separately; it reports only a single annual value for fugitive emissions from well sites. In 2025, the RIA estimates annual costs for well site fugitive controls will be $160 million and that annual benefits will be $150 million (using a 3 percent discount rate). Thus, as a group, fugitive emission controls for well sites do not pass the benefit cost test, with net benefits of negative $10 million, even when using the EPA benefit and cost numbers.

The second set of columns in Table 1-1 correct a number of other issues that were identified with EPA's benefit cost analysis. These include:

1. <u>Oil well completions</u>: EPA underestimated the cost of combustion controls for oil well completions. An adjustment was also made to reflect the fact that many hydraulically fractured development oil well completions are controlled in the baseline scenario. Adjusting the estimated costs and the emission reduction estimates to reflect the fact that many hydraulically fractured development oil well completions are already being controlled in the baseline results in costs that are higher than benefits.

2. <u>Fugitives from well pads</u>: EPA overestimated the emission reductions for fugitive emissions in their analysis. The model plant baseline emissions for both oil and gas well sites were estimated by rounding up the counts of major equipment at a well site and then multiplying by the component counts per major equipment. The resulting estimate was an overstatement of baseline emissions and corresponding emission reductions of 30-35 percent.

[1] Morgenstern, Richard. 2015. The RFF Regulatory Performance Initiative: What Have We Learned? RFF Discussion Paper. RFF DP 15-47.

EPA also excluded many cost elements in their estimates for semi-annual OGI leak screening and repair for well sites. Table 1-1 shows the impact of correcting these major flaws in the EPA cost estimates and correcting the estimated component counts for the model plants. These adjustments show that both oil and gas well sites fail the benefit-cost test. Correcting the issues identified changes the outcome of the benefit-cost analysis for fugitive emissions alone.

3. Pneumatic Pumps: Several corrections were made to the estimates for pneumatic pumps that significantly change the net benefits estimate. These corrections include: a) adjusting the annual operating time for diaphragm pumps to 4 months of the year, on average; and b) correcting the costs of routing the pump vent to an existing control device, consistent with the estimate EPA used for wet seal compressor vents.

The ERM estimates address various deficiencies in the RIA cost estimates. In Sections 3 and 4 we describe the numerous problems with the EPA's SC-CH_4. Putting aside those problems for a moment, even using the EPA's SC-CH_4 estimates, our analysis shows that overall net benefits are negative. The total benefits in 2025 are around $400 million (vs. EPA's $460 million) and the costs are over $810 million (vs. EPA's $310 million) for EPA's preferred regulatory approach (Option 2). Therefore, the overall proposed regulatory program results in a net benefit of -$410 million, and does not pass a benefit-cost test. In addition, virtually all of the source-specific net benefit estimates are also negative.

Table 1-1. Comparison of 2025 Annual Benefits and Costs – Option 2, Low Impact, Discount Rate 3%

Source	Emission Point	EPA Estimates: Reduced CH_4 Emissions (Mt)	EPA Estimates: CH_4 Benefits ($M)	EPA Estimates: Annualized Cost ($M)	EPA Estimates: Net Benefits ($M)	ERM Estimates: Reduced CH_4 Emissions (Mt)	ERM Estimates: CH_4 Benefits ($M)	ERM Estimates: Annualized Cost ($M)	ERM Estimates: Net Benefits ($M)
Well Completions	Hydraulic Fracturing – Development	117,934	$177	$120	$57	122,908	$184	$208	($24)
	Hydraulic Fracturing – Exploration	9,979	$15	$4	$11	10,284	$15	$12	$4
Fugitive Emissions	Well Pads	99,790	$150	$160	($10)	68,838	$103	$508	($405)
	Oil Wells	33,980	$51	$119	($68)	21,685	$33	$338	($305)
	Natural Gas Wells	71,651	$108	$46	$61	47,153	$71	$171	($100)
	Gathering & Boosting Stations	29,937	$45	$17	$28	Not Evaluated (used EPA's estimate)			
	Transmission Compressor Stations	9,072	$14	$3	$11	Not Evaluated (used EPA's estimate)			
Pneumatic Pumps	Well Pads	29,030	$44	$5	$38	11,186	$17	$57	($40)
Pneumatic Controllers	Transmission & Storage Stations	7,983	$12	$0.8	$11	Not Evaluated (used EPA's estimate)			
Reciprocating Compressors	Transmission & Storage Stations	608	$0.9	$0.7	$0.2	Not Evaluated (used EPA's estimate)			
Centrifugal Compressors	Transmission & Storage Stations	3,175	$5	$0	$5	Not Evaluated (used EPA's estimate)			
Total		307,508	$460	$310	$150	263,992	$396	$806	($410)

1.2 *Overview of Issues Associated with the Social Cost of Methane*

There are numerous issues associated with the use of the SC-CH_4 estimate to quantify potential benefits of methane emission controls. The SC-CH_4 is derived using an approach that the EPA claims is "consistent with" the Interagency Working Group (IWG) approach for estimating the SCC. Therefore the SC-CH_4 inherits all of the weaknesses of the SCC and it is far from clear that either the SCC or SC-CH_4 provide the "scientifically and economically defensible" estimates that are required for conducting meaningful benefit–cost analysis. The EPA asked three peer-reviewers to evaluate the SC-CH_4 estimates and they identified serious concerns with estimates. (See Section 3.1)

The SC-CH_4 was derived based on modeling results from three Integrated Assessment Models (IAMs) that are the basis for the SCC estimates as well. The three IAMs predict different climate impacts from the same change in emissions. It is not clear whether this reflects true scientific uncertainty or inconsistencies in the modeling (EPRI 2014).[2] Even if the results do reflect scientific uncertainty, Gillingham et al. (2015)[3] show relying on variation in model outcomes as a measure of uncertainty captures only a small fraction of the total variation in many important climate change outcomes. They also show that assumptions about the rate of technological change can have a profound effect on the estimates of SCC. Most importantly, the monetary damage functions that underlie these IAMs have no theoretical basis (Pindyck 2013).[4]

The range of discount rates used by the EPA reflects the rates typically used in U.S. policy analysis. However, if EPA wants to illustrate the potential global benefits, the illustration should include the discount rates used by other nations Florio and Sirtori (2013)[5] report that discount rates used by governments throughout the world range from 3 to 15 percent. As Pindyck (2013) states, the choice of discount rates in climate change IAMs is arbitrary, yet it has huge effects on the estimated social cost of emissions generated.

[2] S.K. Rose, D. Turner, G. Blanford, J. Bistline, F. de la Chesnaye, and T. Wilson. Understanding the Social Cost of Carbon: A Technical Assessment. EPRI, Palo Alto, CA: 2014. Report #3002004657.

[3] Gillingham et al. 2015. Modeling Uncertainty in Climate Change: A Multi-model Comparison. Cowles Foundation Working Paper. No. 2022.

[4] Pindyck, Robert. 2013. "Climate Change Policy: What Do the Models Tell US". Journal of Economic Literature 2013, 51(3): 860-872.

[5] Florio and Sirtori. 2013. "The Social Cost of Capital: Recent Estimates for the EU Countries. Centre for Industrial Studies. Working Paper Series. http://www.csilmilano.com/docs/WP2013_03.pdf

1.3 Overview of the Impact of Uncertainty

The uncertainties surrounding the benefits and costs are not adequately reflected in the RIA. The EPA guidelines for benefit-cost analysis indicate that quantitative information should typically include both a best estimate, and a range or confidence interval. The RIA reports a range of benefits and costs, but only to reflect uncertainty of whether low producing oil and gas wells are subject to fugitive emissions controls. However, there is uncertainty about the costs (at a minimum, a range should have been generated to reflect standard engineering cost uncertainties) and the SC-CH_4. A recent RFF analysis of RIAs provides explicit support for evaluating the impact of uncertainty, because it can affect the RIA conclusions and may warrant the consideration of alternative regulatory designs (RFF 2015).

This review uses Monte Carlo analysis to provide a more complete picture of the impact of uncertainty. First, we provide a more robust characterization of the distribution of SC-CH_4. This is accomplished by using Monte Carlo data provided by Marten et al. (2014) that shows the full distribution of SC-CH_4 across IAMs, socio-economic scenarios, and discount rates (see Section 4.2 for details). Second, we construct ranges for the cost categories and emission reductions. Uncertainty about the costs is handled by estimating a range of potential costs for each of the major elements of the total costs. Depending on circumstances, the range can encompass both the EPA and ERM in Table 1-1 and/or standard engineering costing procedures.

Table 1-2 shows the results of a Monte Carlo analysis of the net benefits. Uncertainty about benefits is quantified by using data from Marten et al. (2014).

Table 1-2. Summary of the Annual Net Benefits Monte Carlo Results – 2025, EPA Option 2

Emission Source/Sector	Percentiles of Distribution $MM			Probability Net Benefits are Positive	Probability Net Benefits Exceed EPA Estimate
	5th	50th	95th		
Well Completions	-208	-58	266	22%	17%
Fugitive Emissions/Oil Well Pads	-547	-355	-192	0.2%	0.4%
Fugitive Emissions/ Natural Gas Well Pads	-222	-115	78	11%	6%
Pneumatic Pumps/Well Pads	-68	-38	4	6%	2%
Total of Above Categories	-1,044	-557	155	--	--

The results of the Monte Carlo simulation illustrate not only the high degree of uncertainty around EPA's point estimates, but also their improbability. Over all emissions sources/points ERM evaluated, the simulated distributions show that net benefits range between -$1.04 billion and $0.16 billion 90 percent of the time–a range of more than $1.0 billion in a single year. The extreme width of the distribution suggests there is not a meaningful way of concluding net benefits will be positive. Aside from well completions, there is less than a 10 percent chance that net benefits exceed EPA's estimate for the other emission sources/sectors ERM modeled. In the case of fugitive emissions controls at oil wells, the probability is less than 1 percent.

1.4 U.S. VS. GLOBAL IMPACTS

In the RIA analyses, EPA only reports the global benefits for SC-CH_4, despite the fact they are required to show the U.S. benefits. While exact numbers for the U.S. are not provided by EPA, the EPA previously estimated that between 7 percent and 23 percent of global SCC total benefits actually accrue to the U.S.[6] Using this range we computed the U.S. net benefits by subtracting between 7 and 23 percent of total benefits from 100 percent of the costs in the Monte Carlo model. This results in a range of net benefits from -$1.07 to -$0.56 billion in 2025.

[6] EPA 2015. Response to Comments: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866.

2.0 TECHNICAL ANALYSIS OF COST AND EMISSION REDUCTIONS

To understand the basis of the costs and emission reductions that EPA used in the benefit-cost analysis, a detailed review of the Technical Support Document (TSD) for the proposed NSPS Subpart OOOOa was conducted. This section summarizes the key findings from the TSD review and discusses the impacts on the benefit-cost analysis.

2.1 FUGITIVE CONTROLS

The following comments are based on ERM's review of the underlying basis and assumptions that EPA used in their analysis of net benefits for fugitive emissions. The proposed fugitive emission control scenario is semi-annual leak detection and repair (LDAR) using optical gas imaging (OGI) for well sites, gathering and boosting, and transmission and storage. The findings of the review indicate that EPA underestimated the costs of the proposed controls and overestimated the emission reductions.

2.1.1 Fugitive Control Costs

Underestimate of Leak Survey Cost

In the cost estimation for implementing the LDAR requirements under Subpart OOOOa, EPA underestimated the cost of conducting a leak survey at the model well sites. Although EPA estimated the model plant to consist of 2 wells per well site, they used cost data representing an OGI leak survey conducted by a contractor for a single well per well site ($600/single well battery[7]) as the basis of the leak survey costs. The actual cost of the survey, based on the reference document EPA used, would be higher than the value used in the analysis that represents a single well site ($600/single well battery) and lower than the value provided for a multiple well site ($1,200/multiple well battery) that represents on average 5 wells per site. A better estimate based on the reference document used would be a linear scaling between the given cost range, an estimate of $720/model well site, representing 2 wells per well site. EPA also did not include any administrative costs for managing leak surveys conducted by contractors, as indicated in the reference document.

[7] Carbon Limits. "Quantifying cost-effectiveness of systematic LDAR Programs using IR cameras". December 24, 2013. Available at http://www.catf.us/resources/publications/files/CATFCarbon_ Limits_Leaks_Interim_Report.pdf.

Omission of Additional Cost Elements for LDAR Program

The start-up cost of a major monitoring program involves many costs not associated with the routine recurring costs of the regular survey. EPA's cost analysis failed to consider costs associated with training, monitoring device calibration and transportation. These are not insignificant and should be part of EPA's assessment of the costs of the proposed requirements. As indicated in the comments on fugitives, additional costs based on data from companies subject to Colorado Regulation 7 were included to evaluate the impacts to net benefits. Annualized costs associated with semi-annual OGI leak survey and repair based on the CO Regulation 7 estimates are $6,353/yr/well site, compared with EPA's estimate of $2,230/yr/well site. Table 2-1 compares the total annualized costs for fugitive emissions controls at well sites in 2025 using EPA's estimated control cost and ERM's corrected control cost incorporating industry information from CO Regulation 7. The estimated total annualized costs using ERM's corrected estimate is significantly higher–more than three times–than EPA's estimate reported in the RIA. ERM's cost estimate is documented in the fugitive controls comment section.

Table 2-1: Cost Comparison for Fugitive Emissions

Emission Point	EPA Estimates		ERM Estimates	
	Reduced CH_4 Emissions (Mt)	Annualized 2025 Cost ($M)	Reduced CH_4 Emissions (Mt)	Annualized 2025 Cost ($M)
Well Pads	99,790	$160	68,838	$508
Oil Well Site	33,980	$119	21,685	$338
Gas Well Site	71,651	$46	47,153	$171

Omission of Costs for Well Sites in Regulated States

EPA excluded well sites in regulated states from the cost analysis, but did not exempt those sites in the proposed Subpart OOOOa rule. Specifically, EPA excluded well sites in regulated states in their baseline and projections of affected oil and gas well sites in 2020 and 2025. The exclusion of well sites in regulated states has the effect of reducing both costs and emission reductions, so no net effect on cost effectiveness. However, the rule as proposed does not exclude well sites in regulated states, which is not consistent with EPA's cost analysis. If well sites in regulated states are not exempt from Subpart OOOOa requirements, those affected well sites would incur higher costs to implement the additional LDAR requirements, with little to no net emissions reductions. The resulting costs would be higher than EPA estimated if those regulated well sites are not exempt from the rule.

2.1.2 Fugitive Emission Reduction Estimate

Overstatement of Methane Composition for Oil Well Sites

EPA assumed that the methane composition for fugitive leaks from oil well sites was equivalent to gas well sites at 82.9 percent methane by volume. In contrast, EPA assumed a methane composition of 46.7 percent by volume in their analysis of oil well completion emissions and costs. To be conservative, we used 82.9 for fugitive leaks from oil well sites instead of the more realistic 46.7 percent. If we had used the more realistic value, the overall benefit–cost analysis would be further negatively impacted.

Overestimate of Component Counts

EPA's approach for estimating component counts for the model plant gas and oil well sites overstates emissions and emission reductions. EPA rounded up the average counts of major equipment per well site, as well as the number of wells per well site. As shown in Table 2-2 below, the effect of rounding up the wells per well site and the major equipment per well site is an overstatement of the emission reductions as follows:

- Gas well sites: Baseline emissions decrease from EPA's estimate of 4.54 tons CH_4/yr/well site to an unrounded estimate of 3.18 tons CH_4/yr/well site, or a 30 percent reduction in methane baseline emissions and corresponding emission reductions.
- Oil well sites: Baseline emissions decreased from EPA's estimate of 1.09 tons CH_4/yr/well site to an unrounded estimate of 0.70 tons CH_4/yr/well site, or a 36 percent reduction in methane baseline emissions and corresponding emission reductions from correcting the component counts.

Table 2-2. Comparison of EPA Rounded-Up vs. Unrounded Estimate of Baseline Emissions

Model Plant	EPA Baseline using Rounded-Up Data					Corrected Baseline using Unrounded Data				
	EPA Assumed Equipment Counts		EPA Assumed Component Counts		EPA Baseline, tons CH_4/yr/ well site	Corrected Equipment Counts		Actual Component Counts		Actual Baseline, tons CH_4/yr/ well site
Gas Well Sites	Wellheads	2	Valves	114	4.54	Wellheads	1.81	Valves	80	3.18
	Separators	2	Connectors	414		Separators	1.41	Connectors	293	
	In-line Heaters	1	OELs	14		In-line Heaters	0.74	OELs	10	
	Dehydrators	1	PRVs	6		Dehydrators	0.50	PRVs	4	
Oil Well Sites	Oil Wellheads	2	Valves	29	1.09	Oil Wellheads	1.81	Valves	18	0.70
	Separators	1	Connectors	104		Separators	0.72	Connectors	61	
	Headers	1	OELs	1		Headers	0.70	OELs	1	
	Heater/Treaters	1	PRVs	1		Heater/Treaters	0.06	PRVs	1	

Growth Rate Inconsistency

EPA used an inconsistent approach for projecting affected gas well sites for onshore production sector and the gathering and boosting sector. To estimate the number of affected gas well sites and gathering and boosting stations in 2020 and 2025, EPA used an estimated annual growth rate for gas wells. For gas well sites, EPA used a 6.45 percent annual growth rate based on the National Energy Modeling System (NEMS) model as the basis for projecting new gas well sites in the onshore production sector. In contrast, EPA used a 3 percent annual growth rate for new gas wells as the basis for projecting new gathering and boosting stations. If EPA used the same 3 percent growth rate for gas well site projections for the onshore production sector, the overall benefit–cost analysis would be further impacted, meaning the net benefits would be even lower. To be conservative, ERM used 3 percent.

Overestimate of Gathering and Boosting Station Component Counts

EPA's approach for estimating the model plant gathering and boosting station component counts overstates baseline emissions and emission reductions. EPA rounded up the average number of compressors per compressor station in estimating component counts for the model plant baseline emissions. Further, they also used an inconsistent approach for projecting the number of affected gathering and boosting stations in 2020 and 2025. The assumptions EPA used for estimating baseline emissions for the gathering and boosting station model plant and for projecting the number of affected new facilities include:

- 5.0 compressors per station used for model gathering and boosting station component counts. This is based on rounding up the estimated 4.5 compressors per gathering and boosting station;
- 4.5 compressors per station assumption used to project number of new facilities for 2020 and 2025.

The impact of rounding up the number of compressors per gathering and boosting station from 4.5 to 5.0 is a 10 percent overstatement of the component counts, which translates into 10 percent overstatement of baseline emissions and emission reductions. Note that this overstatement was conservatively not corrected in the revised benefit cost analysis figures.

2.2 *Pneumatic Pumps*

EPA estimated emission reductions and costs of controls for the production sector. A review of the cost analysis for the proposed controls for pneumatic pumps indicates that EPA underestimated costs and likely overstated emission reductions.

2.2.1 *Pneumatic Pump Control Costs*

EPA estimated the cost of control, i.e., routing a pneumatic pump vent to an existing control device, as a one-time cost of $2000. Using a 7 percent discount rate over 10 year estimated life of a pump, the annualized cost of control was estimated at $285/year. EPA's reference for the cost estimated is from a NG STAR Fact Sheet[8] for routing a glycol dehydrator circulation pump vent to an existing vapor recovery unit (VRU). The value assumed is an underestimate of the total cost that would be required for engineering design and piping installation for a vent system retrofit to route a very low flow, low pressure vent stream to an existing flare or VRU. This estimate is also inconsistent with the estimated cost of $23,252 assumed for routing a wet seal compressor vent to an existing control device (Section 8.4.4.3 of TSD). ERM believes the value of $23,252 is closer to the uninstalled capital cost that would be incurred. Utilizing EPA's assumed 7 percent interest rate, this equates to an annualized cost of $3,308. Note that this estimate does not include the engineering and design analysis needed to ensure that the control device has adequate capacity and that the flow characteristics for a low flow, low pressure source can safely be routed into the existing flare or VRU header. The costs also do not include the recurring annual costs associated with monitoring and testing at sites not otherwise subject to Subpart OOOOa.

[8] Natural Gas EPA Pollution Preventer. 2011. "PRO Fact Sheet No. 203: Pipe Glycol Dehydration to Vapor Recovery Unit". http://www.epa.gov/gasstar/documents/pipeglycoldehydratortovru.pdf

2.2.2 *Pneumatic Pump Emission Reduction Estimate*

EPA's estimates of baseline emissions and emission reductions are overstated, as indicated in the sections below.

Overestimate of Diaphragm Pump Baseline Emissions

EPA assumed that both diaphragm pumps and chemical injection pumps operate continuously, year round, i.e., 8,760 hours of operation per year. However, EPA acknowledges that diaphragm pumps are used for circulation of heat transfer fluids to prevent freezing, meaning that they are commonly only operated seasonally. A better estimate of the actual time in operation is 3 – 4 months per year. Using 4 months per year as an average time in service, the emission reductions for diaphragm pumps are one-third the value that EPA assumed in the cost analysis.

Overstatement of Methane Composition for Oil Well Sites

EPA assumed that the methane composition for the vent from all pneumatic pumps in production is consistent across all well sites at 82.9 percent methane by volume. Similar to the discussion above for methane composition for fugitives from oil well sites, a better estimate of methane composition is 69.5 percent by volume. This corrected estimate was assumed in the revised estimates of net benefits from pneumatic pump controls at production well pads.

Uncertainty in the Projected Number of New Sources in 2020 and 2025

The projected number of new pneumatic pump sources in 2020 and 2025 was based on an estimated annual increase in the number of pumps using a 10 year average of pneumatic pump net increases from the Inventory of U.S. GHG Emissions and Sinks: 1990-2013.[9] EPA only used the net increases from year to year (i.e., the positive net increase values), instead of the overall net change over the 10 year period. This approach would likely overstate the number of new pumps, because it is not reflective of a true change over the 10 year period.

Another source of uncertainty is EPA's estimate of the split between chemical injection and diaphragm pumps that EPA assumed in the projection of affected sources in 2020 and 2025. Specifically, EPA assumed that new and replaced pumps were evenly split 50/50 between diaphragm and piston pumps.[10] This reference cited by EPA has no information on pump demographics in the O&G industry. Since the estimated baseline

[9] U.S. EPA. 2015. "Inventory Of U.S. Greenhouse Gas Emissions and Sinks. 1990-2013." http://www3.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2014-Annex-3-Additional-Source-or-Sink-Categories.pdf

[10] GlobalSpec. Undated. "Diaphragm Pumps Information." Available at http://www.globalspec.com/learnmore/flow_transfer_control/pumps/diaphragm_pumps

emissions from piston pumps are a factor of 10 lower than diaphragm pumps, the baseline, emission reductions, and net benefits estimates are highly sensitive to this assumption. EPA used different assumptions of the pump type split between diaphragm and piston pumps for their analysis of an alternate control option (instrument air system), ranging from 25, 50, and 75 percent for each pump type.

Corrected Net Benefits Estimate for Pneumatic Pumps

ERM used the following corrections to estimate a revised net benefits estimate from pneumatic pumps at well sites:

- Annual cost of $3,308/well site;
- Methane composition for pneumatic pumps at oil well sites of 69.5 percent by volume (compared to 82.7% by EPA); and
- Diaphragm pumps operational 4 months per year, on average.

The comparison of benefits and costs estimated by EPA and corrected to account for the issues identified above are shown below.

Table 2-3: Cost and Emissions Comparison for Pneumatic Pumps

Emission Point	EPA Estimates		ERM Estimates	
	Reduced CH_4 Emissions (Mt)	Annualized 2025 Cost ($M)	Reduced CH_4 Emissions (Mt)	Annualized 2025 Cost ($M)
Well Pads	30,934	$5.1	11,186	$57

2.3 *OIL WELL COMPLETIONS*

EPA proposed the following controls for hydraulically fractured and refractured oil well completions:

- Subcategory 1 wells – non-wildcat, non-delineation wells: reduced emission completions (REC) and combustion device;
- Subcategory 2 wells – wildcat, delineation wells: combustion device.

Based on ERM's review, the control costs may be understated and the emission reductions overstated.

2.3.1 Oil Well Completion Control Costs

Underestimate of Oil Well Completion Combustion Device

The cost of a completion combustion device was estimated to be $3,723 in 2012$ based on the 2012 NSPS by EPA. Based on public comments to EPA from the Independent Producers Association of New Mexico (IPANM) on the Methane White Papers, members estimated the cost for flaring oil well completions at over $10,000. This is believed to be a more reasonable cost to rent, transport, install, operate and remove separator and flare equipment.

2.3.2 Oil Well Completion Emission Reduction Estimate

Overestimate of Oil Well Completion Baseline Emissions and Emission Reductions

EPA's estimates of the baseline emissions and emission reductions from hydraulically fractured and refractured oil well controls are overstated. EPA incorrectly assumes that all hydraulically fractured oil well completions and recompletions are not controlled, except in Wyoming and Colorado. This assumption is not correct as many companies already use REC and/or combustion devices to control the flowback emissions from oil well completions. Therefore, EPA's baseline emissions are overstated and the resulting emission reductions achievable are also overstated.

Corrected Estimate for Oil Well Completions

ERM used the following corrections to estimate a revised net benefits estimate from oil well completions:

- Assumed 25 percent of developmental oil wells are already controlled. Note that the estimated controlled hydraulic fracturing at oil well sites is based on industry experience and is above and beyond the state control requirements.;
- Cost of combustion device for oil well completions estimated at $10,000.

Table 2-4 compares the benefits and costs estimated by EPA and the corrected values.

Table 2-4: Cost and Emissions Comparison for Oil Well Completions

Emission Point	EPA Estimates		ERM's Estimates	
	Reduced CH_4 Emissions (Mt)	Annualized 2025 Cost ($M)	Reduced CH_4 Emissions (Mt)	Annualized 2025 Cost ($M)
Hydraulic Fracturing – Development	117,934	$120	122,908	$208
Hydraulic Fracturing - Exploration	9,979	$4	10,284	$12

2.4 *Centrifugal and Reciprocating Compressors*

2.4.1 Compressor Control Costs

The control costs for routing a wet seal compressor vent to an existing control device was estimated by EPA to be $23,252, as indicated in Section 2.2.1 above. We believe this cost to be more representative of the true uninstalled capital cost of the control option.

2.4.2 Compressor Emission Reduction Estimate

Overestimate of Centrifugal Compressor Baseline Emissions

EPA based the wet seal centrifugal compressor baseline emissions on the emission factors from the US GHG Inventory: Emission and Sinks 1990-2012. The emission factors for wet seal centrifugal compressors was based on a sampling of 48 wet seal centrifugal compressors, and derived from the emission rate and percent of time the compressor was in pressurized mode. According to the Interstate Natural Gas Association of America in comments to EPA on the Methane White Paper on Compressors,[11] the US national GHG inventory values are reported to be over 30 times higher than values found in Subpart W reporting. Since Subpart W reporting reflects recent industry practices, and is based on measured emission rates for compressors in transmission and storage, it is considered to be more accurate.

Uncertainty in the Projected Number of New Sources in 2020 and 2025

EPA projected the number of new and modified reciprocating and centrifugal compressor sources for 2020 and 2025 based on the same approach used for pneumatic pumps. Specifically, EPA estimated the number of reciprocating and centrifugal compressor installations based on a 10 year average of compressor net increases from the inventory of US GHG Emissions and Sinks: 1990-2012. Only the years of positive net increase were averaged, neglecting the years of estimated decline in number of sources. This approach introduces significant uncertainty since a simple average over the same 10 year period (i.e., counting years of source declines) yields a negative change for centrifugal compressors in both transmission and storage segments and negligible increase for reciprocating compressors in the transmission segment. Table 7 shown below presents the difference between the approach EPA used and the simple 10 year average.

[11] INGAA. "INGAA to 'Environmental Protection Agency (EPA) Methane White Paper: Oil and Natural Gas Sector Compressors'", available at: http://www.ingaa.org/File.aspx?id=21896.

Table 2-5: Number of New Compressors in a Typical Year Used in Analysis

Segment	EPA Approach: 10 Year Average of Net Increases	10 Year Simple Average	EPA Approach: 10 Year Average of Net Increases		10 Year Simple Average	
	# New Reciprocating Compressors	# New Reciprocating Compressors	# New Centrifugal Compressors		# New Centrifugal Compressors	
			Wet Seal	Dry Seal	Wet Seal	Dry Seal
Transmission	24	0	0	2	-1	1
Storage	43	-17	1	5	-3	2

2.5 *Pneumatic Devices*

2.5.1 *Pneumatic Device Emission Reduction Estimate*

Overestimate of Pneumatic Device Baseline Emissions and Emission Reductions

EPA estimated that all bleed devices installed at transmission and storage stations are high bleed, because vendor research did not have enough information to estimate the prevalence of high- versus low-bleed devices. This assumption overstates the number of high-bleed devices and consequently, the nationwide baseline emissions and potential emission reductions achievable by replacing them with low-bleed devices.

Uncertainty in the Projected Number of New Sources in 2020 and 2025

EPA projected the number of new and modified bleed pneumatic devices for 2020 and 2025 based on the same approach used for pneumatic pumps and compressors. Specifically, EPA estimated the number of new bleed devices based on a 10 year average of net increases from the inventory of US GHG Emissions and Sinks: 1990-2012. Only the years of positive net increase were averaged, neglecting the years of estimated decline in number of sources. This approach introduces significant uncertainty since a simple average over the same 10 year period (i.e., counting years of source declines) yields a negative change for bleed devices in the storage sector.

3.0 SOCIAL COST OF METHANE

The RIA used a paper by Marten et al. (2014) to determine the SC-CH_4 estimates. The RIA claims that the Marten approach is "consistent with" methods used to develop the SCC. This is important to the EPA, as the SCC has been approved for use in RIAs by OMB; to the extent that there is consistency of the SC-CH_4 with the SCC, then the imprimatur of the OMB may attach to the SC-CH_4. Given that OMB approval does not necessarily verify that the SCC provides a scientifically and economically defensible basis for a benefit-cost analysis, in this section we examine consistency between the SC-CH_4 and the SCC.

The methodology used by Marten et al. (2014) is similar to the IWG approach to estimating SCC in that it uses the same:

- Three IAMs;
- Five socio-economic and emissions scenarios;
- Discount rates; and
- Approach for averaging social costs across scenarios and IAMs.

One of the three IAMs, FUND, handles CH_4 explicitly. The other two IAMs, PAGE and DICE, were modified by Marten et al. using a simple CH_4 gas model to make it consistent across IAMs. The EPA asked three peer-reviewers to provide an assessment of the SC-CH_4 and concluded that the reviewers generally agree that the SC-CH_4 estimates are consistent with the SCC estimates. [12] Moreover, because OMB guidance supports the use of SCC estimates, the EPA decided that a finding concluding that the SC-CH_4 was consistent with SCC estimates justified the use of the SC-CH_4 estimates, and further stated that the SC-CH_4 estimates were an "analytical improvement" over their exclusion.

After reviewing the available data and studies, as well as the reviewers' comments, ERM believes that the use of the SC-CH_4 estimates is not warranted at this time, for the following reasons:

1. The three peer reviewers' endorsement of the "consistency" of the SC-CH_4 estimates was far more modest than the EPA asserts. Further, the reviewers identified key uncertainties with the approach being used.

[12] EPA. Whitepaper on Valuing Methane Emissions Changes in Regulatory Benefit-Cost Analysis, Peer Review Charge Questions, and Responses.

2. All of the challenges with estimating the SCC apply to estimating the SC-CH_4. These challenges seriously affect the scientific and economic reliability and usefulness of both the SCC and SC-CH_4 in the foreseeable future.
3. The SC-CH_4 (and SCC) estimates are highly uncertain and the causes of the uncertainty are not well understood.

3.1 Modest Peer Review Endorsement of the "Consistency" of the SC-CH_4 Estimates

The EPA notes that benefit-cost analysis must provide estimates that are produced in a "scientifically and economically defensible manner". Interestingly, the seven charge questions from EPA to the peer reviewers did not directly ask whether the SC-CH_4 estimates are scientifically and economically defensible. Instead, the charge questions are concerned with: the consistency of the SC-CH_4 estimates with the SCC estimates; whether the latest direct SC-CH_4 estimates are better than SC-CH_4 estimates based on global warming potential (GWP); and whether better SC-CH_4 estimates currently exist. That the reviewers are never asked whether the SC-CH_4 estimates used in the RIA are reliable and appropriate for use in policy analysis is an important omission.

The EPA asserts that the reviewers generally agree that the SC-CH_4 estimation methods are consistent with SCC. This clearly is an overstatement. One reviewer agrees that the SC-CH_4 estimates are consistent with the SCC. However, a second reviewer offers this assessment:

The term "Consistent" can have many interpretations. I will say that the Marten et al. SC-CH_4 estimates are computed in a similar way as the SC-CO_2 estimates, so in this regard, the two estimates are "consistent." However, CO_2 is more explicitly modeled in the three models than CH_4 so in this regard they are not "consistent."

The reviewer goes on to point out that inconsistencies reflect the limitations of models and that there are gaps that need to be understood, despite the Marten et al. attempts to address them.

The third reviewer also expressed concerns about specific consistency issues. Although all of the damages for SCC and SC-CH_4 are reported on a per ton basis, the magnitude and duration of the perturbations that are used to estimate the damages vary across all of the IAMs for SCC and are different than what is used for SC-CH_4. For example, for SCC, DICE uses a one Giga-ton carbon shock over a decade, while Marten et al. use a 1 million ton shock in a single year. Similarly, the SC-CH_4 models that compute CH_4 concentrations and radiative forcing differ from PAGE's approach for non-CO_2 emissions. The implications of these differences are not well understood. More importantly, the reviewer believes that any consistency that does exist is a "serious problem", because it means the SC-CH_4 inherits all of the problems of the SCC estimates. This reviewer also points out that while the Marten et al. paper has been peer-reviewed, the underlying IAM models and the multi-model averaging approach have not.

Thus, in our view, reliance upon the SC-CH_4 estimates based on their purported consistency with the SCC cannot be justified.

3.2 *ALL OF THE CHALLENGES WITH ESTIMATING THE SCC APPLY TO ESTIMATING THE SC-CH_4*

The challenges with using the SCC estimates are well documented. We summarize the key issues here.

EPRI (2014) provides an in-depth technical assessment of the SCC estimates. Their goal is to understand the key drivers of the damage estimates, the reliability of the results, and whether estimates can be improved. They focus on three areas: climate; emissions; and damages.

They find significant differences across the three IAMs in the predicted temperature change and sea level rise change from the same increase in emissions and same underlying socioeconomic conditions. The temperature responses result from differences in the modeling of the carbon cycle, non-CO_2 radiative forcing, and climate sensitivity. Even in the short-term, through 2040, the IAMs can yield temperature changes that vary across models by a factor of two for the same emissions scenario.

The economic damage functions linked to these temperature changes and sea level rise estimates are also very different. For example, one IAM shows gains in GDP through 2100 for some scenarios with increased emissions, while the other two IAMs show losses for the same scenarios and emissions. The three models also show wide variation in the impact on the GDP of different countries and for different types of economic costs (i.e., agriculture, heating and cooling). The damage functions themselves are arbitrary and not based on significant empirical data or economic theory (NERA 2014).[13] For example, one can easily plot two damage functions that are both consistent with the few current data that are available, but which produce widely different damages in the distant future.

EPRI concludes that the significant differences in the structure of the models, which lead to significant differences in the damages estimates, are not well understood or explained. As a result, EPRI concludes that it is difficult to assess whether the

[13] NERA. 2014. A Review of the Damage Functions Used in Estimating the Social Cost of Carbon. Comments prepared for the American Petroleum Institute.

differences reflect true scientific uncertainty (and therefore they should be retained) or the differences are topics that should be resolved and standardized.

The EPRI results also call into question the USG approach of averaging the SCC models across different socioeconomic scenarios to form a single estimate of the SCC for a particular discount rate. EPRI concludes that the inconsistencies in the models, the lack of robustness of the models, and the fact that they may not be truly independent may make such averaging inappropriate. In our view, such averaging may also be inappropriate because it assumes that each estimate is equally reliable and obscures the true uncertainty about the SCC that exists in the scientific literature. Gillingham et al. (2015) conclude that the concept of relying on an ensemble of models to capture total uncertainty is not theoretically sound and furthermore, based on their empirical data, is a "deficient" approach, because it fails to capture the full range of uncertainty that affects the models. Moreover, they believe their results highlight the importance of additional research on the role economic variables and damage functions to improve climate-change policy making.

EPRI provides six specific recommendations for improving public and scientific confidence in SCC estimates: conducting more detailed analyses of the differences among the IAMs to better understand and determine which differences and uncertainties to retain; additional peer review of the IAMs; integration (i.e., weighting of the results); better documentation of the approach; more complete justification on the methods; and guidance on their use.

Other reviewers have been even less enthusiastic. Pindyck's (2013) review of the IAMs led him to conclude:

These models have crucial flaws that make them close to useless as tools for policy analysis: certain inputs (e.g., the discount rate) are arbitrary, but have huge effects on the SCC estimates the models produce; the models' descriptions of the impact of climate change are completely ad hoc, with no theoretical or empirical foundation; and the models can tell us nothing about the most important driver of the SCC, the possibility of a catastrophic climate outcome. IAM-based analyses of climate policy create a perception of knowledge and precision, but that perception is illusory and misleading.

The SCC estimates' sensitivity to model parameters can also be found in the SC-CH_4 estimates. ERM obtained the DICE model, data and computer code from Dr. Marten. In our evaluation, we found that changing the parameter on temperature squared in the assumed damage function of the DICE model for SC-CH_4 by 0.000020405 (25%) changes the estimated SC-CH_4 for 2025 by $200. Similarly, changing the global total factor productivity for the assumed process that generates output by 0.0075805 (25%) changes the SC-CH_4 by $350. Our evaluation demonstrates that small changes in arbitrary functions have significant effects on SC-CH_4 estimates.

3.3 *THE SC-CH_4 ESTIMATES ARE NOT WELL UNDERSTOOD AND HAVE NOT BEEN FULLY VETTED*

As discussed above, the SCC estimates suffer from significant uncertainties about their sensitivity to the myriad assumptions embedded in the models, the impacts of which are poorly understood. These same uncertainties also plague the SC-CH_4 estimates and are understated in the RIA. The uncertainties undermine the usefulness of resulting values in benefit-cost analysis at this time.

First, the degree of uncertainty in the estimates is unrepresented in the RIA. For any discount rate and emission year, the RIA reports the SC-CH_4 as a single number. However, looking across the IAM models reveals a significant range of potential values. For example, for a 3 percent discount rate and incremental emissions occurring in 2020, the SC-CH_4 is reported as $1,200 in Marten et al. However, Appendix B of the Marten et al. paper indicates that across the 3 IAMs and 5 socioeconomic policy scenarios (including the scenario average), the average SC-CH_4 is $1,200 with a standard deviation of $251 (or approximately 20 percent of the average value). However, even this range underreports uncertainty. Each of those 15 estimates (i.e., 3 IAMs and 5 scenarios) is the average of 10,000 Monte Carlo simulations. Looking across the entirety of the SC-CH_4 estimates from these simulations yields a standard deviation of $1,720, 138 percent of the average SC-CH_4, nearly 6 times as high.

It is critical that the causes of variability of the SC-CH_4 estimates be fully understood before they are used in policy analysis. As the authors of the FUND model note, many of the assumptions about the appropriate distributions that should be used to characterize the uncertainty are expert "guesses" (Anthoff, et al. 2014)[14]. Furthermore, in another paper Anthoff reports that parameters on cooling energy demand, migration, climate sensitivity, and agriculture are uncertain and have a significant impact on model results, but the first two have not been largely researched (Anthoff, et al. 2013).[15]

EPA benefit cost-guidance also recommends providing undiscounted values, which would provide more insights into the issues surrounding uncertainty and the appropriate discount rate. (EPA 2010, pp. 6-18). However, that data was not discussed in the RIA.

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[14] Anthoff, D., et. al. 2014. The Climate Framework for Uncertainty, Negotiation and Distribution (FUND), Technical Description, Version 3.9. Accessed on the FUND Website, November 2014.

[15] Anthoff, D., Richard T. 2013. The uncertainty about the social cost of carbon: A decomposition analysis using FUND.

ERM estimated the undiscounted benefits for the four socioeconomic scenarios using the DICE model. Modifying Dr. Marten's computer code, we produce the undiscounted social costs by year for 1 ton emission of CH_4 that occurs in 2025 and 2045, and calculate the percentage of total social costs occurring before and after year 2100. Table 3.1 shows the results of our evaluation. The results show that the vast majority ($4 out of every $5 dollars) of social costs associated with methane emissions after the year 2100, which is the time period for which the temperature rise, baseline emission, and socio-economic projections are speculations at best. Higher discount rates effectively shorten the time period that are included in the benefits estimates.

Table 3-1. Percent of Undiscounted Social Costs of Methane Occurring Before and After 2100 (2007$)*

	Emission in 2025		Emission in 2045	
Socio-economic Model	**Percent 2100 and Earlier**	**Percent after 2100**	**Percent 2100 and Earlier**	**Percent after 2100**
Image	12%	88%	13%	87%
Merge	19%	81%	21%	79%
Message	20%	80%	21%	79%
MiniCam	10%	90%	12%	88%

*Climate sensitivity parameter set to 3.

The potential role of discount rates is also important because of the supposed global nature of the benefits. While lower discount rates may be the norm for the U.S. and developed countries, the discount rates for other countries (who will enjoy most of the benefits) may be significantly higher. For example, Lopez (2008) reports that a social discount rate for nine Latin American countries could range from 3 to 7 percent, depending on future growth rates[16]. Florio and Sirtori (2013)[17] report that discount rates being used throughout the world range from 3 to 15 percent. Therefore, if the EPA prefers to illustrate their estimated global benefits, they should base them on global discount rates. Moreover, a 7 percent discount rate is still the preferred rate regulatory impact analysis by the OMB and should be included in the RIA for the required analysis of domestic benefits (OMB, 2003)[18].

To better understand the impact of using a higher discount rate, we estimated SC-CH_4 using the DICE model. The results show that moving to the 7 percent discount rate reduces the SC-CH_4 estimates by over two-thirds (Table 3-2). Technically, this result

[16] Lopez. Humberto. 2008. The Social Discount Rate: Estimates for Nine Latin American Countries. http://www.researchgate.net/publication/23723498_The_Social_Discount_Rate_Estimates_for_Nine_Latin_American_Countries

[17] Florio and Sirtori . 2013. "The Social Cost of Capital: Recent Estimates for the EU Countries." Centre for Industrial Studies. Working Paper Series. http://www.csilmilano.com/docs/WP2013_03.pdf

[18] OMB. 1992. Circular No. A-94. Revised.

only applies to the DICE model. However, if the same percentage decline is applied to the 2020 SC-CH_4 EPA used in the RIA, the value would drop from $1,300 to $403.

Table 3.2. Impact of Discount Rates on SC-CH_4 in the DICE Model (2007$)

Emission Year	3 Percent Discount Rate	7 Percent Discount Rate	Difference (%)
2025	$974	$311	-$641 (-68%)
2045	$1,658	$598	-$1,059 (-64%)

*Climate sensitivity parameter set to 3. SC-CH_4 values are the average across the four socio-economic scenarios).

4.0 UNCERTAINTY ANALYSIS

The RIA did not adequately consider the uncertainty of both the benefits and the costs associated with the NSPS OOOOa. Both EPA guidelines (EPA, 2010) and OMB guidelines (OMB, 2003) indicate that evaluating the impact of uncertainty on benefits and costs is a key consideration in rule making. Moreover, the OMB explicitly states that when the degree of uncertainty has a significant impact on net benefits, agencies should consider conducting additional research prior to rulemaking. Instead of including plausible ranges for the key benefits and costs and acknowledging the uncertainty about the true values of underlying parameters and assumptions, EPA relied upon point-estimates for costs and benefits. As a result, the RIA gives an unrealistic assessment of the impact of the proposed rules.

ERM developed a Monte Carlo model to provide a more realistic assessment of the net benefits of the NSPS OOOOa. Monte Carlo simulation is a standard method for evaluating the impact of regulations when there is substantial uncertainty. It provides insights into the likelihood that benefits will exceed costs when there are multiple parameters and assumptions that are uncertain.

ERM developed the Monte Carlo model for five emission sources/points:

- Hydraulically fractured development oil well completions,
- Hydraulically fractured exploration oil well completions,
- Fugitive emissions from oil wells,
- Fugitive emissions from natural gas wells, and
- Pneumatic pump operations at well sites.

These emissions sources/points comprise over 90 percent of the control costs and over 80 percent of the controlled emissions EPA estimates.

The model is estimated by calculating costs and benefits for 5,000 draws from the probability distributions for the values of parameters and assumptions underlying the quantification of the number of regulated units, control costs, emission control volumes, natural gas recovery revenue and SC-CH_4.

ERM's Monte Carlo analysis provides a more complete analysis of the net benefits. The results show that there is significant uncertainty about the costs and benefits of the proposed rule and that it is likely that costs will exceed benefits, especially when considering the net benefits accruing to the U.S.

The cumulative probability distribution functions (CDF) and 90 percent confidence interval for costs, benefits and net benefits in 2025 (i.e., a 90 percent change the true value is actually within that range) from all emissions sources/points are presented in Figure 4-1. The average 2025 global net benefit estimate is -$0.5 billion with a standard deviation of $0.41 billion. The degree of variation in net benefits means that there is a 90 percent chance that true global net benefits will be between -$0.92 and $0.17 billion. Based on the distribution, there is an 89 percent chance that net benefits in 2025 are lower than EPA's own estimate (uncorrected) of $0.12 billion. The difference is starker when considering that somewhere between 7 and 23 percent of methane control benefits accrue to the United States. Based on the model, there is a 90 percent chance that net benefits for the U.S. will range between -$1.07 and -$0.56 billion.

Figure 4-1. Estimated Costs, Benefits and Net Benefits of the NSPS OOOOa Under Uncertainty for All Emissions Points and Sources ($MM)

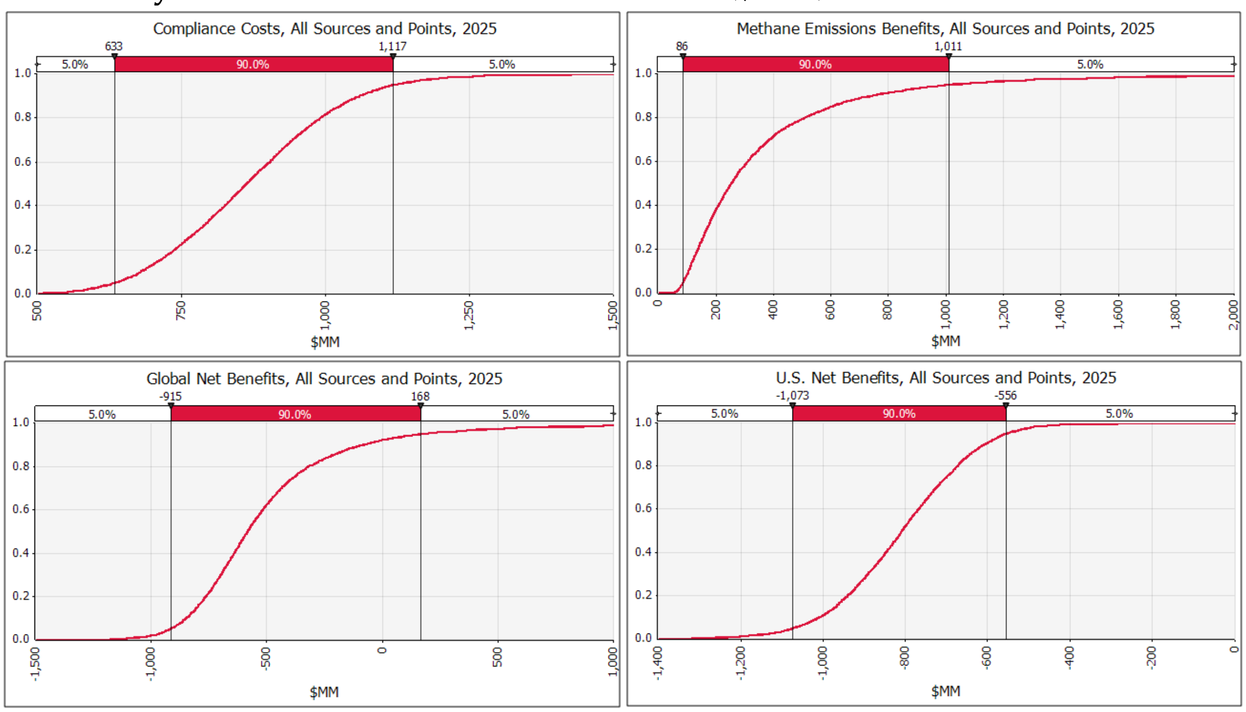

Table 4-1 summarizes the distributions of costs, benefits and net benefits in 2025 generated by ERM's Monte Carlo model for each emission source/point evaluated, compared with EPA's estimate. EPA's estimated costs are always towards the lower end of the distribution, while estimated benefits are well above the median. This implies that EPA's costs and benefits are less probable rather than more probable. For many emissions sources, EPA's estimated net benefits are positive, whereas net benefits are negative at the middle of the distributions generated by ERM's model. One example of this is fugitive emissions controls at gas wells. EPA's estimated 2025 net benefits are $0.62 billion, whereas the median of ERM's distribution is -$0.12 billion.

Table 4-1. Estimated Costs, Benefits and Net Benefits of the NSPS OOOOa Under Uncertainty for Selected Emissions Sources and Points ($MM)

		Costs				Benefits				Global Net Benefits				U.S. Net Benefits	
Source	Point	5th	50th	95th	EPA	5th	50th	95th	EPA	5th	50th	95th	EPA	50th	EPA
Well Completions	Development	153	199	243	120	18	143	429	173	-197	-55	241	53	-182	-94
	Exploration	7	11	15	4	1	8	37	14	-11	-3	25	10	-9	-2
Fugitive Emissions	Oil Wells	240	391	579	120	5	24	117	51	-547	-355	-192	-69	-386	-112
	Gas Wells	104	179	277	46	11	53	255	108	-222	-115	78	62	-168	-30
Pneumatic Pumps	Well Pads	26	52	78	5	2	10	51	39	-68	-38	4	34	-50	1

In the following sections, we describe parameters and assumptions underlying the estimates of total costs and benefits, and the probability distributions fit to those ranges to implement the Monte Carlo simulation.

4.1 Methane Emission Benefits

EPA used the SC-CH_4 estimate from Marten et al. 2014 based on the 3 percent discount rate to report monetary benefits of methane emission reductions. While EPA "emphasiz[ed] the importance and value of considering the benefits calculated using all [four] SC-CH_4 estimates", the RIA did not report a comparison of benefits and costs using the wide-range of SC-CH_4 estimates derived by Marten for alternative policy scenarios, IAMs and discount rates (RIA, Table 1-4, Note 1).

Using Monte Carlo methods, Marten generated 10,000 estimates of SC-CH_4 for each of four future economic policy scenarios (excluding the overall policy-average) simulated using each of the three IAMs and three discount rates (i.e. 36 combinations) [19] For each combination, the SC-CH_4 is future social costs for an additional 1 ton of methane emitted in a particular year discounted back to 2012 at each of the three alternative discount rates. The 10,000 estimates for each combination are based on uncertainty parameters embedded in each IAM. In using the Marten et al. results, the RIA calculated the overall average SC-CH_4 from the IAM and policy distributions separately

[19] The economic policy scenarios are IMAGE, MERGE, MESSAGE and MiniCAM.

for each of the three discount rates. The EPA focused on the overall average SC-CH_4 for the 3 percent discount rate to value benefits of methane emission controls for the RIA.[20]

ERM obtained Dr. Marten's Monte Carlo simulations for this evaluation. The data reveal the significant uncertainty in the SC-CH_4, and underscore the inappropriate nature of using only average values of SC-CH_4. Table 4-2 summarizes Marten's distributions of the 2020 SC-CH_4 within each IAM, varying by policy scenario and using the 2.5 and 5.0 percent discount rates.[21] Each of the distributions is skewed towards higher estimates of SC-CH_4. The mean estimate exceeds the median estimate by 33 to 140 percent. The FUND and PAGE models are characterized by an enormous degree of variability. Overall, the estimated SC-CH_4 typically varies by more than 230 percent of the mean, ranging from 75 to 310 percent across IAMs. FUND generates extreme lower and upper bounds (social benefit or costs of methane), ranging from over -$0.5 to $0.25 million per ton.

Table 4-2. Empirical Distributions of SC-CH_4 in 2020 Developed by Marten et al. 2014 (2007$ per ton)

IAM	N	Mean	Median	Standard Deviation	Range (Min / Max)	
DICE	80,000	858	645	636	101	3,729
FUND	80,000	1,341	978	4,157	-679,393	225,935
PAGE	80,000	1,305	544	2,119	-11	28,645
Overall	**240,000**	**1,168**	**708**	**2,728**	**-679,393**	**225,935**

ERM used Marten's empirical distributions to model uncertainty in methane emissions benefits, but we used a different approach than the RIA.[22] Using all 240,000 SC-CH_4 estimates, we found the single probability distribution function that best described the data. The probability distribution we used is a log-normal distribution with a mean of $1,236 and a standard deviation of $1,439 per ton (2012$).[23] This provides a single function that characterizes uncertainty across IAMs, policy scenarios, and discount rates. ERM estimated the 2025 SC-CH_4 by multiplying each draw of the 2020 SC-CH_4 by 1.162.[24, 25] This approach more fully captures the degree of uncertainty than the RIA

[20] EPA averaged means of the SC-CH_4 distribution over policy scenario within each IAM, and then over IAMs, generating a point-estimate for each discount rate. EPA also averaged the 95th percentile of the SC-CH_4 for the 3 percent discount rate. The 2020 SC-CH_4 that EPA reported in the RIA ranged from $580 to $3,500 per ton across the three discount rates and the 95th percentile of the distribution from the 3 percent rate (RIA Table 4-3).
[21] ERM discarded the distributions for the 3.0 percent discount rate because they are bounded distributions for the 2.5 and 5.0 percent discount rates.
[22] ERM obtained the distributions directly from Dr. Marten.
[23] ERM inflated Dr. Marten's SC-CH_4 estimates from 2007$ to 2012$ using the GDP implicit price deflator.
[24] @Risk Formula: RiskLognorm(1235.9,1438.7,RiskShift(-15.64)).
[25] This scalar reflects the ratio of the 2025 to 2020 policy- and IAM-average SC-CH_4 the EPA derived from Marten et al 2014 using the 2.5 and 5.0 percent discount rates (RIA Table 4-3). This method eliminates draws where the SC-CH_4 in 2025 is less than the SC-CH_4 in 2020.

approach, but does not capture the full range that might exist as described by Gillingham et al. (2015).

EPA estimated the monetary benefits of methane emissions associated with the NSPS OOOOa by multiplying the SC-CH_4 by tons of controlled methane emissions. Total controlled methane emissions are derived by multiplying controlled emissions per regulated unit by the number of regulated units.

Table 4-3 reports the range of uncertainty about per unit methane emission reductions that ERM used in the Monte Carlo model. As described in Section 2, EPA over-estimated per unit methane emission reductions for several emission sources/points. Unless otherwise noted, ERM used EPA's estimate as the upper bound, ERM's corrected estimate as the most likely value, and 70 percent of ERM's estimate as the lower bound of a Beta-PERT probability distribution.

Table 4-3. Distribution of Annual Controlled CH_4 Emissions Used in ERM's Monte Carlo Model

Emission Source/Sector	Units	Min.	Most Likely	Max.	Notes
Fracking Well Completions [a]	Mt/ completion	6.46	9.23	12.00	Most Likely: EPA. Min/Max: -/+ 30% of EPA estimate.
Fugitive Emissions / Oil Wells	Mt/ well site	0.29	0.42	0.65	Max: EPA estimate (baseline 1.09 x 40% reduction). Most Likely: EPA estimate after eliminating compounded rounding and revised methane concentration for oil wells (Table 2-3). Min: Most Likely x 0.7.
Fugitive Emissions / Natural Gas Wells	Mt/ well site	1.34	1.91	2.72	Max: EPA estimate (baseline 4.54 x 40% reduction). Most Likely: EPA estimate after eliminating compounded rounding (Table 2-3). Min: Most Likely x 0.7.
Pneumatic Pumps / Diaphragms (O&G Wells)	Mt/pump	0.72	1.03	3.29	Max: EPA estimate. Most Likely: Operational for 4 months per year to reflect seasonal use and revised methane concentration for oil wells (Table 2-3). Min: Most Likely x 0.7.
Pneumatic Pumps / Pistons (O&G Wells)	Mt/pump	0.24	0.34	0.36	Max: EPA estimate. Most Likely: Revised methane concentration for oil wells. Min: Most Likely x 0.7.

[a] The emission reductions are multiplied by a scalar ranging from 0.75 to 1.0 to reflect that up to 25 percent of development oil wells are already controlled.

4.2 *PROJECTED SCOPE OF REGULATION*

Total costs and benefits associated with NSPS OOOOa increase with the number of new and modified emissions sources projected in 2020 and 2025. EPA projected growth of sectors and market segments within the oil and gas industry using historical data, but did not consider the considerable variability of annual growth and inventories of units subject to the regulation apparent from the very data utilized. For example, by choosing to exclude years of contraction, EPA projected 581 new pneumatic storage devices annually over 10-years when the actual average annual growth was -230 devices. Had they assumed growth was 0 during those years of contraction (i.e. included all years in the denominator but only positive values in the numerator), EPA would have projected 232 new devices annually. By failing to recognize uncertainty in annual growth within elements of the oil and gas industry, EPA has given a false sense of precision about the total cost impact and societal benefit associated with NSPS OOOOa.

Tables 4-4, 4-5 and 4-6 report the ranges in parameters ERM used to model uncertainty in the number of regulated units existing in 2020 and 2025. Unless otherwise noted, ERM used EPA's estimate as the most likely value and developed the range as +/- 30 percent. ERM modeled the probability distribution of all but the parameters for new CIPs (pneumatic pumps) using the Beta-PERT distribution.

Table 4-4. Range in Inputs for Projected Fracking Well Completions Used in ERM's Monte Carlo Model

Input/Parameter	Min.	Most Likely	Max.	Notes
Oil Well Completions, 2012	14,357	14,357	14,357	Used EPA estimate.
Fraction Exploration Wells (%)	2.66	3.8	4.94	
CAGR of Developmental Wells (%yr)	-0.007	-0.005	-0.004	
CAGR of Exploration Wells (%/yr)	4.2	6.0	7.8	

Table 4-5. Range in Inputs for Projected Oil & Gas Well Pads Subject to Fugitive Emissions Regulations Used in ERM's Monte Carlo Model

Input/Parameter	Min.	Most Likely	Max.	Notes
Well Density (# Wells/Pad)	1	1.81	2	Max: EPA estimate, rounded. Most Likely: EPA estimate unrounded. Min: 0.7 x Most Likely.
Oil Wells				
Unregulated Oil Wells, 2012 (# wells)	22,599	32,284	41,969	
Low-Producing Oil Wells (%)	31	43	59	
Oil Well Growth (%/yr)	0.22	0.32	0.42	
Natural Gas Wells				
Unregulated NG Wells, 2012 (# wells)	4,683	6,691	8,698	
Low-Producing NG Wells (%)	21	30	39	

NG Well Growth (%/yr)	3.0	6.45	8.39	Most Likely: EPA estimate. Min: EPA estimate used in Gathering & Boosting analysis. Max: Most Likely x 1.3

Table 4-6. Range in Inputs for Projected Pneumatic Pumps at Oil & Gas Well Pads Used in ERM's Monte Carlo Model

Input/Parameter	Min.	Most Likely	Max.	Notes
New CIPs-Oil Wells (#/yr)	0	803	1,400	*Triangular distribution. Most Likely: EPA estimate. Min/Max: Min/Max of historical data on annual new oil well CIPs.
New CIPs-NG Wells (#/yr)	800	1,500	2,200	*Triangular distribution. Most Likely: EPA estimate. Min/Max: -/+ 1 std. deviation of the fitted distribution to historical data on annual new gas well CIPs.
Replaced CIPs-All Wells (#/yr)	476	680	884	
Fraction Diaphragm (v. Piston) (%)	25	50	75	Most Likely: EPA estimate. Min/Max: ranges used by EPA in similar analysis.

4.3 COMPLIANCE COSTS

EPA estimated total compliance costs by multiplying the projected number of regulated units by unit compliance costs. Tables 4-7, 4-8 and 4-9 report the ranges in the unit cost parameters ERM used to model uncertainty in compliance costs. The most likely value of the distribution for annualized costs and/or underlying parameters is most commonly the value ERM derived by correcting technical flaws in EPA's costing and finding estimates for key elements of costs omitted by EPA, as described in Section 2. Unless otherwise noted, EPA's estimate is the lower bound, while the upper bound is a 30 percent increase in the most likely value. We use the Beta-PERT distribution to model uncertainty.

Table 4-7. Range in Inputs and Distribution of Hydraulically Fractured Well Completions Control Costs Used in ERM's Monte Carlo Model

Input/Parameter	Units	Min.	Most Likely	Max.	Notes
Capital Costs					
REC & Combustion	$/completion	17,183	23,459	30,497	
Combustion only	$/completion	3,723	10,000	13,000	
Fraction REC & Combustion (Development Wells)	%	35	50	65	
Useful Life	# Yrs.	1	1	1	
Annualized Cost – Development Wells	$/completion	6,944	16,729	21,606	
Annualized Cost –	$/completion	3,723	10,000	13,000	

Exploration Wells					

Table 4-8. Range in Inputs and Distribution of Fugitive Emissions Control Costs at Oil and Natural Gas Well Sites Used in ERM's Monte Carlo Model

Input/Parameter	Units	Min.	Most Likely	Max.	Notes
Well Sites Density	wells/site	15.4	22	28.6	
Annualized Cost	$/well site	2,230	6,353	8,259	Min.: EPA estimate. Most Likely: ERM estimate based on CO Regulation 7. Max.: 1.3 x Most Likely.

Table 4-9. Range in Inputs and Distribution of Pneumatic Pumps Control Costs at Oil and Natural Gas Well Sites Used in ERM's Monte Carlo Model

Input/Parameter	Units	Min.	Most Likely	Max.	Notes
Route to existing flare	$/CIP	1,966	23,252	30,228	
Useful Life	# Yrs.	10	10	10	
Annualized Cost	$/CIP	280	3,308	4,304	

4.4 NATURAL GAS SAVINGS

Where appropriate given the nature of the sector, EPA deducts revenue associated with natural gas recovered from avoided methane emissions from emission control costs.[26] EPA valued estimated natural gas recovered at a price of $4.00/Mcf. Using a point estimate fails to recognize the inherent volatility of commodity markets, as demonstrated by the current landscape of and outlook for oil and gas commodity prices.

[26] EPA estimated the recovered volume by scaling tons of controlled methane emissions by specific technical factors. ERM's Monte Carlo model does not model uncertainty around these technical factors. Rather, uncertainty in recovered volumes is function of uncertainty in the volume of controlled emissions.

Attachment F

Comparison of the LDAR Requirements Proposed in Subpart OOOOa to Existing State LDAR Programs

Comparison of OOOOa Requirements to Colorado Regulation 7, Wyoming Chapter 8, Ohio General Permit requirements, and Pennsylvania Permit requirements.

Highlighted cells indicate where the proposed OOOOa requirements are more stringent than the state level requirements.

OOOOa Reference	OOOOa Item	Colorado Reg 7	Wyoming Ch. 8	Ohio	PA
60.5397a(a)	Monitor all fugitives as defined	Fugitive components not as extensive as OOOOa			
60.5397a(b)	Develop a corporate-wide monitoring plan (MP)	No MP requirement	LDAR protocol by 1/1/2017 for each facility	LDAR program should be developed & implemented. No deadline.	No MP requirement
60.5397a(c)(1)	MP: Specify monitoring frequencies	In Rule, based on emission actuals	Rule states no less frequently than quarterly	Rule states no less frequently than quarterly for 4 consecutive quarters.	Requires quarterly LDAR
60.5397a(c)(2)	MP: Technique for determining fugitive emissions	Not clear	No	No	Not required
60.5397a(c)(3)	MP: Manuf and Model of detection equipment	Not required	Not required	FLIR or an analyzer meeting USEPA Method 21 or 40 CFR 60, Appendix A	Not required
60.5397a(c)(4)	MP: procedures and timeframes for ID and repair detections	5 days to fix	No	No	Within 15 days otherwise DOR
60.5397a(c)(5)	MP: procedures and timeframes for verifying repairs	Rule specific monitoring timeframes (15 d to re-monitor after the	No	No	Leak must be demonstrated as repaired

OOOOa Reference	OOOOa Item	Colorado Reg 7	Wyoming Ch. 8	Ohio	PA
		fix)			
60.5397a(c)(6)	MP: Length of time records will be kept	Two Years	Five yrs.	Five yrs.	Five yrs.
60.5397a(c)(7)(i)(A),(B)	MP: Third party verification of IR camera	Not required	Not required	Not required	Not required
60.5397a(c)(7)(ii)	MP: Procedure for daily verification check	No	No	No	No
60.5397a(c)(7)(iii)	MP: Procedure for determining max viewing distance	No	No	No	No
60.5397a(c)(7)(iv)	MP: Procedure for determining max wind speed to conduct survey	No	No	No	No
60.5397a(c)(7)(v)(A)	MP: How operator will ensure adequate thermal background	Not required	Not required	Not required	Not required
60.5397a(c)(7)(v)(B)	MP: How operator will deal with adverse conditions (wind)	Not required	Not required	Not required	Not required
60.5397a(c)(7)(v)(C)	MP: How operator will deal with interferences (steam)	Not required	Not required	Not required	Not required
60.5397a(c)(7)(vi)	MP: Training and XP prior to performing surveys	Not required	Not required	Not required	Not required
60.5397a(c)(7)(vii)	MP: Procedures for calibration and maint. Must comply with manufacturer	Not required	Not required	Same	Same
60.5397a(d)	Site Specific Monitoring Plan (SMP)	Not required	LDAR protocol by 1/1/2017 for each facility	Not required	Not required
60.5397a(d)(1)	SMP: Deviation from MP	Not required	Not required	Not required	Not required
60.5397a(d)(2)	SMP: Site Map	Not required	Not required	Not required	Not required
60.5397a(d)(3)	SMP: Defined Walking Path	Not required	Not required	Not required	Not required
60.5397a(e)	Each survey shall observe each fugitive component	Same	Same	Rule states each ancillary component with FLIR	Same
60.5397a(f)(1)	Initial survey NEW well site: 30d of first well completion or upon startup	Initial survey between 15-30 days of commencing	Not required	90 days of startup & quarterly thereafter.	w/in 60 d of startup

OOOOa Reference	OOOOa Item	Colorado Reg 7	Wyoming Ch. 8	Ohio	PA
		operation			
60.5397a(f)(1)	Initial survey Modified well site: 30d of modification	Applies to existing and new sites	Not required	Not required	w/in 60 d of modification
60.5397a(f)(2)	Initial survey NEW Comp Sta.: 30d of startup	Within 90 days or 30 days of startup depending on fugitive emissions	Not required	Not required	w/in 180 d of startup
60.5397a(f)(2)	Initial survey Modified Comp Sta.: 30d of modification	Initial survey between 15-30 days of commencing operation	Not required	Not required	w/in 180 d of modification
60.5397a(g)	After Initial Survey, Semiannual, at least 4 months apart	No	Not required	Rule has conditions (i.e. < 2.0% leakers for 4 quarters)	Annual for Well sites, Quarterly for Comp Sta
60.5397a(h)	2 Consecutive Semi > 3% leakers, then quarterly	Frequency based on emissions not leakers	Not required	Any 1 semi-annual or annual >2.0% leakers, then quarterly	Annual for Well sites, Quarterly for Comp Sta
60.5397a(i)	2 Consecutive Semi < 1% leakers, then annually	Based on emissions not leakers, Annual evaluation of emissions for step-downs	Not required	No, 2 Consecutive Semi < 2% leakers, then annually	Annual for Well sites, Quarterly for Comp Sta
60.5397a(i)	2 Consecutive Qtrly or Annual 1% - 3% leakers, then semiannually	No, only modification	Not required	Not required	Annual for Well sites, Quarterly for Comp Sta
60.5397a(j)(1)	Repair replace within 15 days of find. If infeasible, then next shutdown or within 6 mos.	Repair within 5 days not 60/shutdown requires, Otherwise delay of repair	Not required	1st attempt w/in 5 calendar days, must be repaired w/in 30 days of find.	Yes, but no shutdown w/in 6 months requirement,

OOOOa Reference	OOOOa Item	Colorado Reg 7	Wyoming Ch. 8	Ohio	PA
					just repair at next shutdown
60.5397a(j)(2)	Resurvey within 15 days of find.	No, 15d after fix	Not required	No	Yes, to verify repair
60.5397a(j)(2)(i)	For repair not during survey when found, Method 21 or IR survey with 15days of finding.	M21 or IR.	Not required	Not required	Yes M21 or IR. Leak Detector and soap are also allowed
60.5397a(j)(2)(ii)(A)	If M21, resurvey <500ppm	Same requirement	Not required	Not required	Yes
60.5397a(j)(2)(ii)(B)	If M21, resurvey using 60.5401a(g)	No, soapy water allowed	Not required	Not required	No, soapy water allowed
60.5397a(j)(2)(iii)(A)	If IR, repair is no indication using IR	Same requirement	Not required	Not required	Same requirement
60.5397a(j)(2)(iii)(B)	If IR, Does this require a resurvey entire facility [60.5397a(a)] - all fugitives as defined?	No	No	No	No
60.5397a(k)	Recordkeeping (RK)	Same requirement	Same requirement	Yes	Yes
60.5397a(k)(1)	RK: Date of Survey	Same requirement	Same requirement	Yes	Yes
60.5397a(k)(2)	RK: Beginning and End time of Survey	Not Required	Not required	Not required	Not required
60.5397a(k)(3)	RK: Name of Operator performing Survey. Note training and experience of operator	Not Required	Not required	Yes to Name, No to requirement on training and/or experience	Not required
60.5397a(k)(4)	RK: Ambient Temp, Sky Cond, Max wind speed at time of survey	Not Required	Not required	Not required	Not required
60.5397a(k)(5)	RK: Note any Deviation from MP, or a statement no deviation were made	Not Required	Not required	Not required	Not required
60.5397a(k)(6)	For each finding (LK)	--	--	--	--
60.5397a(k)(6)(i)	LK: Location	Not Required	Not required	Not required	Not Required
60.5397a(k)(6)(ii)	LK: Digital Photo w/Lat/Long	Not Required	Not required	Not required	PA is requesting

OOOOa Reference	OOOOa Item	Colorado Reg 7	Wyoming Ch. 8	Ohio	PA
					but not in rule
60.5397a(k)(6)(iii)	LK: Date of successful repair	Same requirement	Not required	Same requirement	Same requirement
60.5397a(k)(6)(iv)	LK: Instrument used to resurvey	Specify type of instrument used in inspection	Not required	Not required	Yes
60.5397a(l)	Meet reporting requirements 60.5420(b)(7)	State Annual Report, Aggregated Summary	LDAR Protocol, if applicable, by 1/1/2016	Specific requirements included	Submit Initial Compliance Report within 6 months