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August 2, 2016

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

Re: Request for Administrative Reconsideration EPA's Final Rule "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources"

Dear Administrator McCarthy:

The American Petroleum Institute ("API") hereby submits this petition for administrative reconsideration of the final rule entitled "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources," published at 81 Fed. Reg. 35824 (June 3, 2016) ("Subpart OOOOa").

Pursuant to section 307(d)(7)(B) of the Clean Air Act ("CAA"), 42 U.S.C. § 7607(d)(7)(B), where it is impracticable to raise an objection during the period of public comment or if the grounds for such an objection arise after the public comment period (but within the time specified for judicial review), and if such objections are of central relevance to the outcome of the rule, the U.S. Environmental Protection Agency ("EPA" or "Agency") is required to reconsider a rule.

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. Most of our members conduct oil and gas development and production operations and, thus, will be directly impacted by this final rule.

This document is divided into two parts. In the first part, we present the issues for which we believe that administrative reconsideration is warranted. In the second part, we present a number of additional issues where we believe changes to the rule are needed, but where we are not asking for administrative reconsideration. These additional issues are included because we believe it would be efficient for EPA to make these changes in the rulemaking that the Agency undertakes to accomplish administrative reconsideration of the first set of issues

We look forward to continuing to work with the Agency on improving the rule and are submitting this request for reconsideration to address a number of key issues identified in the finalized rule.

Thank you for your consideration of this request for administrative reconsideration. Please do not hesitate to contact me (202.682.8340) if you have questions or need more information.

Sincerely,

Howard J. Feldman

CC: Janet McCabe, EPA
Steve Page, EPA
Peter Tsirigotis, EPA
David Cozzie, EPA
Bruce Moore, EPA

API Request for Administrative Reconsideration EPA's Final Rule "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources"

August 2, 2016

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I. ISSUES FOR WHICH WE REQUEST ADMINISTRATIVE RECONSIDERATION

1. The requirements for Certification by Professional Engineer finalized in §60.5411a(d) for closed vent systems and §60.5393a for pneumatic pump technical infeasibility determination at brownfield sites should be removed and stayed pending reconsideration.

The final rule includes requirements for a professional engineer (PE) to certify closed vent system designs for storage vessels and centrifugal compressors as well as certify when it is not possible to control an affected pneumatic pump at a brownfield site. The provisions requiring PE certification were not included in the proposed rule and should be reconsidered, given the inability to raise an objection during the public comment period, and stayed pending reconsideration to allow a full notice and comment process. Comments presented here would have been provided to EPA during the proposal comment period, if we were provided proper notice and comment ability. Our objection is of central relevance to the outcome of the rule because it provides substantial support for the need to revise the rule to eliminate the PE certification requirement.

Companies will be burdened with the additional costs and project delays for a third party PE to design and certify closed vent systems as few companies have an adequate staff of in-house PEs. While API appreciates EPA's recognition of some of the challenges of having such PE reviews completed, including extending the compliance date for affected pneumatic pumps from 60 days to 180 days following publication, there are still fundamental problems with EPA's approach and no extension was provided for storage vessels and centrifugal compressors. Other issues associated with the requirement to have PE certification include the following:

- The PE certification process does not add any significant value and EPA has not justified the extra expense and burden of PE certifications when there are provisions in place for compliance report submittals approved by a certifying official.
  - There is already a 'general duty obligation' in § 60.11(d) for owners and operators to ensure proper operation, and maintenance of equipment. PE certification does not relieve companies of this duty.
  - The certifying official is already required to sign off on a company's compliance with all applicable provisions.
  - There is no quantifiable benefit to the environment from this additional review, while there is significant expense involved.
  - There are direct costs associated with the PE certification process, whether companies support in house licensure of engineers or leverage third parties. However, no costs associated with obtaining PE approval were considered or provided for review during the proposal process.
- Development of in-house PE capacity will take several years. Development of a sufficient number of in-house licensed PEs to cover all states where a company operates will take considerable time. Meanwhile, though EPA has determined third-party PE certification is unnecessary, many operators will have to depend heavily on outside consultant PEs in the foreseeable future. This will add additional cost and delays to projects that EPA has not accounted for.

- It takes at least four years of experience plus additional time to satisfactorily pass required testing to obtain a PE license.
- At present, most company engineers are not PEs, and PE licensure is not a condition of employment or career development. While trained and qualified and with years of experience in the design of production facilities, these engineers are not called upon to formally certify equipment designs.
- EPA's allowance of PEs not licensed in the state where certification is needed conflicts with state and PE licensure requirements that a PE must be licensed in the state where they practice. Consequently, a PE cannot ethically certify closed vent system design or technical infeasibility based on EPA's standard, which is inconsistent and contradictory to PE licensure rules of practice. This limitation invalidates the Subpart OOOOa definition of *Qualified Professional Engineer.*

Therefore, EPA should reconsider the PE certification requirement and remove it entirely from the rule to relieve the redundancy it creates relative to each company's existing general duty obligations and the certifying official's acknowledgment. At a minimum, EPA should broaden the requirements and allow alternatives to PE Certification such as to require all designs to undergo engineering review and approval. A general duty to properly design CVS or determine technical infeasibility should be adequate for enforcement.

An administrative stay of the PE certification requirement pending the outcome of the reconsideration proceeding is needed and justified because, even though the effective date of the requirement for affected pneumatic pumps has been extended to 180 days after publication of the rule, it is highly unlikely that EPA will complete reconsideration prior to that date. As a result, absent a stay, companies will confront the costs, uncertainties and compliance barriers described above – all of which can and should be avoided through amendment of the rule.

2. Coincident with PE certification requirements for pneumatic pump technical infeasibility determinations, EPA introduced but inadequately defined "greenfield" site as there is no clarity with respect to determining when a greenfield site transitions to a brownfield site. As well, it is inappropriate to categorically prohibit a claim of technical infeasibility for greenfield sites.

The terms "greenfield" and "brownfield" sites and the use of these terms in determining compliance obligations were not proposed. Therefore, industry had no opportunity to comment. In addition, this issue is of central relevance to the outcome of the rule because, for the reasons described below, changes to the final rule are needed. Consequently, administrative reconsideration of this issue is justified.

Without a clear definition with respect to the boundary of when greenfield ends and brownfield begins, operators will be put in an untenable situation if "greenfield" is considered synonymous with "new" for NSPS thereby removing future technical infeasibility determinations for the entire life of a well site. Initial design for construction of a greenfield site may not require installation of a pneumatic pump or a control device for the early operational period of a well site. At some point later in the life of a well (which could be years), site design requirements may change where a new control and/or pump is installed and a technical infeasibility determination is justified but not available if the site is considered greenfield throughout the life of the site. Even for a new site, process or control device design requirements may not be compatible with controlling pneumatic pump emissions.

For example, a new site design only requires installation of a high pressure flare to handle emergency and maintenance blowdowns. It may not be feasible for a low pressure pneumatic pump discharge to be routed to a high pressure flare.

Another and likely more common example would be if a new greenfield site design calls for installation of a pneumatic diaphragm pump but no control device is present. Rather, only a process heater or boiler is present. The design and operation of a given pneumatic pump and co-located process heater or boiler may not be compatible. The heater and boiler will be designed based on the process it needs to support without regard to the additional capacity or operational need to control a pneumatic pump. More specifically, due to the small size (generally 125,000 Btu per hour to 2.5 mmBtu per hour) of many heaters/boilers used at well sites, burner capacity may be insufficient to compensate for emission combustion of additional large pneumatic diaphragm pump discharge and may result in frequent safety trips and burner flame instability (i.e. high temperature limit shutdowns, loss of flame signal, etc.). Additionally, industry guidelines (i.e. NFPA 86) would prohibit the use of boilers/heaters as control devices where the following criteria are not met: the operating temperature being a minimum of 1400°F, presence of emission source safety interlocks, etc.

In summary, a process heater or boiler may only operate a few weeks or months per year or the fuel use rating of the heater may be insufficient to handle the additional capacity of a pump discharge or both. While this issue could be dealt with at "brownfield" sites as technically infeasible, there is no such allowance for this capacity issue at "greenfield" sites.

Without a technical infeasibility option, having to design and build a process heater or boiler around the capacity needs to adequately and safely control a pneumatic pump when it otherwise wouldn't be designed with this feasibility in mind is equivalent to requiring installation of a new control device, and additional cost will unnecessarily be incurred. This concept is contradictory to the rule not requiring installation of a control device or process equipment for the sole purpose of controlling a pneumatic pump.

EPA should allow for technical infeasibility determinations at all well sites and not attempt to segregate sites by greenfield or brownfield. Use of greenfield and brownfield needs to be deleted from the rule. If the two terms remain, API recommends that EPA add a timeline which defines when "greenfield site" ends and brownfield begins. API believes brownfield begins after startup of production at new well sites.

3. Clarification is required regarding location of separator finalized in §60.5375a for well completion operations.

In NSPS OOOOa, a requirement was added in §60.5375a(a)(1)(iii) "*You must have a separator onsite during the entirety of the flowback period, except as provided in paragraphs (a)(1)(iii)(A) through (C) of this section*" that was not included in the proposed regulation. Comments presented here would have been provided to EPA during the proposal comment period, if we were provided proper notice and comment ability. Our objection is of central relevance to the outcome of the rule because it provides support for the need to revise the rule to accurately reflect EPA's intent.

The rule does not provide a definition of "on-site". For wells that flow to centralized facilities or well pads, there will not be gas gathering or flowlines that go to the well head, only the centralized facility or well pad. Also, there would not be equipment located with the well to use the gas as fuel; therefore, there would be no where to send the recovered gas except to a flare.

In VI.E.1 of the Preamble to Subpart OOOOa, EPA discusses the issue of the requirement to have a separator onsite for subcategory 1 wells. An excerpt is provided here (emphasis added):

> *"… we do not have sufficient data to consistently and accurately identify the subcategory or types of wells for which these circumstances occur regularly or what criteria would be used as the basis for an exemption to the REC requirement such that a separator would not be required to be onsite for these specific well completions. In order to accommodate these concerns raised by commenters, the final rule requires a separator to be onsite during the entire flowback period for subcategory 1 wells (i.e., non-exploratory or non-delineation wells, also known as development wells), but does not require performance of REC where a separator cannot function. We anticipate a subcategory 1 well to be producing or near other producing wells. We therefore anticipate REC equipment (including separators) to be* ***onsite or nearby, or that any separator brought onsite or nearby can be put to use.*** *For the reason stated above, we do not believe that requiring a separator onsite would incur cost with no environmental benefit."*

In the above discussion, it is clear that EPA recognizes the intent to allow use of a nearby separator as part of an inline or reduced emission completion. However, the requirement in §60.5375a((a)(iii) only references "separator onsite", which is inconsistent with EPA's intent that the separator does not necessarily have to be located on the specific wellsite in order to satisfy requirements of the rule.

EPA should amend the text in §60.5375a(a)(1)(iii) to also include reference to separators both onsite or nearby clarifying that operators may opt to use production separators at a nearby production site, and the separator does not need to be located at the specific well site being hydraulically fractured. EPA should update §60.5375a(a)(1)(iii) as noted below.

§60.5375a(a)(1)(iii):

> *You must have a separator onsite or otherwise available for use nearby during the entirety of the flowback period.*

4. The requirements in the final rule to document and report claims of technical infeasibility related to capturing of emissions during a well completion were not proposed and should be removed from the final rule.

Dating from the proposed edits to Subpart OOOO of July 17, 2014[1], EPA provided an additional three options for the disposition of flowback gas beyond routing to a gas flow line or collection system.

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[1] 79 FR 41756

Specifically, Subpart OOOO has allowed for gas to also be *"re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve"*.

These three alternate options are very rarely utilized, if ever. API members are not aware of any scenarios where gas has been re-injected into the well undergoing hydraulically fracturing or injected into another well. Beyond that, these alternatives are not utilized because the gas is not of sufficient quality to rely on as onsite fuel source or raw material for another useful purpose.

API did not previously raise concerns with these alternatives when they were introduced in 2014 as they were only potential alternatives. However, under the recordkeeping requirement in §60.5420a (c)(1)(iii)(A), EPA finalized additional requirements.

§60.5375a in the Proposed Subpart OOOOa read:

> *(2) All salable quality recovered gas must be routed to the gas flow line as soon as practicable. In cases where salable quality gas cannot be directed to the flow line due to technical infeasibility, you must follow the requirements in paragraph (a)(3) of this section.*
>
> *(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. Completion combustion devices must be equipped with a reliable continuous ignition source.*

When EPA finalized Subpart OOOOa, these two paragraphs of §60.5375a were revised to read:

> *(2) [Reserved]*
>
> *(3) If it is technically infeasible to route the recovered gas as required in § 60.5375a(a)(1)(ii), then 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. Completion combustion devices must be equipped with a reliable continuous pilot flame.*

Under the proposed language (and the language which preceded it in the rule), operators were authorized to route gas to a completion combustion device if salable quality gas could not be directed to the flow line due to technical infeasibility. Optionally, operators could also re-inject gas into the well or another well, use the gas as an onsite fuel source, or use it for another useful purpose that a purchased fuel or raw material would serve.

Under the finalized language, operators must try all four options provided by EPA prior to routing gas to a completion combustion device and also document the infeasibility of each of the four options as described below.

The text in red in the excerpt below was not in the proposed rule, but was added to the final version of the rule.

§60.5420a (c)(1)(iii)(A):

> *For each well affected facility required to comply with the requirements of §60.5375a(a), you must record: The location of the well; the United States Well Number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time of each attempt to direct flowback to a separator as required in §60.5375a(a)(1)(ii); the date and time of each occurrence of returning to the initial flowback stage under §60.5375a(a)(1)(i); and the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery and disposition of recovery (i.e., routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve); duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours. In addition, for wells where it is technically infeasible to route the recovered gas to any of the four options specified in §60.5375a(a)(1)(ii), you must record the reasons for the claim of technical infeasibility with respect to all four options provided in that subparagraph, including but not limited to; name and location of the nearest gathering line and technical considerations preventing routing to this line; capture, reinjection, and reuse technologies considered and aspects of gas or equipment preventing use of recovered gas as a fuel onsite; and technical considerations preventing use of recovered gas for other useful purpose that that a purchased fuel or raw material would serve.*

The comments presented here would have been provided to EPA during the proposal comment period, if we were provided proper notice and comment ability. Our objection is of central relevance to the outcome of the rule because it provides substantial support for the need to revise the rule.

API believes there is a burden from the final rule language that was not considered during the proposal. More importantly, the requirement for operators to record technical infeasibility with respect to each of the four alternatives provided in the rule provides no benefit since these are not true, viable alternatives. The only scenario that should require documentation of infeasibility is the routing of recovered gas to a flow line.

Therefore, API requests EPA to modify the final rule language as follows:

§60.5375a to read:

> *(2) [Reserved]*
>
> *(3) If it is technically infeasible to route salable quality gas to a flow line or collection system, then 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. Completion combustion devices must be equipped with a reliable continuous pilot flame.*

§60.5420a (c)(1)(iii)(A) to read:

> *(A) For each well affected facility required to comply with the requirements of §60.5375a(a), you must record: The location of the well; the United States Well Number; the date and time of the*

onset of flowback following hydraulic fracturing or refracturing; the date and time of each attempt to direct flowback to a separator as required in §60.5375a(a)(1)(ii); the date and time of each occurrence of returning to the initial flowback stage under §60.5375a(a)(1)(i); and the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery and disposition of recovery (i.e., routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve); duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours. In addition, for wells where it is technically infeasible to route the recovered gas ~~to~~ from the separator into a gas flow line or collection system, ~~as specified in §60.5375a(a)(1)(ii),~~ you must record the reasons for the claim of technical infeasibility. ~~with respect to all four options provided in that subparagraph, including but not limited to; name and location of the nearest gathering line and technical considerations preventing routing to this line; capture, reinjection, and reuse technologies considered and aspects of gas or equipment preventing use of recovered gas as a fuel onsite; and technical considerations preventing use of recovered gas for other useful purpose that that a purchased fuel or raw material would serve.~~

5. Flares for control of Subpart OOOO affected facilities Should Not be Subject to 40 CFR § 60.18 retroactively.

In its Final Rulemaking of both NSPS Subparts OOOO and OOOOa, EPA removed the exemption from compliance with 40 CFR § 60.18 for flares in Table 3 General Provisions. By this action, it could be interpreted that EPA has perhaps inadvertently and certainly improperly imposed a retroactive application of the standards for the design and operation of flares under 40 CFR § 60.18 used to control Subpart OOOO affected facilities, including those associated with maximum velocity restrictions. As indicated by the preambles to both the proposed and final rulemakings, EPA did not consider the potential retroactive effect of this change as it pertains to flares used to control all Subpart OOOO affected facilities, specifically including, but not limited to, flares used to control vapors from process unit affected facilities at onshore natural gas processing plants subject to NSPS Subpart OOOO. In addition, EPA confounds the issue further by its suggestion that the removal of the prior exemption under Subpart OOOO stands only as a clarification of its intent in response to petitions for reconsideration received under that rule.[2] Regardless of EPA's claimed basis for the removal of the exemption and if the changes are interpreted to apply retroactively, EPA's final rulemaking fails to adequately consider the impact the change has on operators who have designed and installed high velocity flares (e.g. sonic) based on the prior exemption in Table 3 at onshore natural gas processing plants to control Subpart OOOO process unit affected facilities between August 24, 2011 and September 18, 2015.

EPA suggests that changes to Subpart OOOO do not constitute a retroactive change of standards and references section VI.H of the preamble for more information regarding this issue.[3] In the proposed rulemaking, EPA acknowledged it was aware of flares used to control Subpart OOOO affected facilities

[2] See Chapter 14 of EPA's Response to Comments - Amendments to Subpart OOOO at page 14-3.
[3] Id.

that are not able to meet the maximum velocity requirements under 40 CFR 60.18 during periods of startup, shutdown, emergency and/or maintenance activities.[4] However, in section VI.H.5 of the preamble to the final rule, EPA dismisses the effect of the rule on flares at gas processing plants which cannot meet the subject velocity requirements during startup, shutdown, emergency or maintenance, and focuses only on flares used to control storage vessels, pneumatic pump, centrifugal or reciprocating compressors, which EPA suggests are able to be routed by closed vent system to low pressure flares.[5] EPA's dismissal on this point doesn't address the use of existing flares subject to NSPS Subpart OOOO by virtue of the flares' usage at gas processing plants to control both maintenance/upset emissions from relief valves and fugitive emissions from these same relief valves that are subject to leak detection and repair (LDAR) regulations under Subpart OOOO. These relief valves cannot be routed to a low pressure flare as these valves operate with either low/no flow (fugitive emissions control) or extremely high flow (maintenance/upset emissions control). During the high flow events, data suggests the flares used to control Subpart OOOO process units at onshore natural gas processing plants can potentially exceed the maximum velocity restrictions of 40 CFR § 60.18 (b) and (c).

An interpretation of retroactive application of 40 CFR § 60.18 in Subpart OOOO for high velocity flares constructed between August 24, 2011 and September 18, 2015 to control process unit equipment leaks and pressure relief events while exempt from §60.18 as specifically listed in Table 3, would create an immediate compliance burden that will result in significant costs to replace these flares. There is no other compliance alternative available. For this reason, API respectfully requests the EPA reconsider the retroactive application of 40 CFR § 60.18 for flares in Table 3 and retain the exemption in Subpart OOOO.

[4] 80 FR 56593, 56646 .
[5] 81 FR 35824, 35866-35867.

II. ADDITIONAL ISSUES

1. Clarification is required for boilers and process heaters used to reduce emissions, particularly as used for pneumatic pumps.

A. There must be a clear definition of control device and recognition that boilers and process heaters are not control devices that are subject to control design requirements in Subpart OOOOa.

Under Subpart OOOOa, the provisions related to "control device" and "routed to a process" or "route to a process" are inconsistent, confusing, and in some instances, conflicting. This is particularly the case with regard to boilers and process heaters in the context of controlling pneumatic pumps. Sections 13 and 24 of our December 4, 2015 comments discussed these issues in detail.

In Chapter 5 of its Response to Comments, EPA's explanation for not making API's requested changes relies primarily on its requirement that control of pumps does not need to meet the 95% control efficiency (§60.5393a(b)(4)) and that allowances have been made for technical infeasibility. However, at greenfield sites, EPA disallows technical infeasibility in the final rule and mandates 95% control efficiency (§60.5393a(b)(1)), making the agency's rationale only partially correct in its discussion of control efficiency and technical infeasibility allowances (see issue Item 2 of this letter for greenfield/brownfield sites). At brownfield sites, EPA requires reporting of design control efficiency if less than 95% (§60.5420a(b)(8)(i)(C)).

Inferring from the final rule, EPA appears to distinguish the issue of whether a boiler/heater is a control or process device by where the vent stream to be combusted is placed. §60.5413a(a)(3) exempts a boiler/heater from testing requirements if the vent stream is tied into the primary fuel or is the primary fuel for the heater firebox. This exemption indicates that EPA treats boilers/heaters as a process device. Conversely, if the vent stream is directed at the flame zone, then the boiler/heater appears to be considered a control device under the rule per §60.5412a(a)(1)(iv).

Boilers and process heaters are not designed as control devices regardless of where the vent stream is placed and are not purchased and put into service based on any inherent control efficiency design. Consequently, boilers and process heaters, at least with respect to pneumatic pumps, should only be considered as process devices, which is inherent of their operational use. If EPA intends to have these devices considered for reducing emissions from diaphragm pneumatic pumps, there should be no associated control efficiency listed in §60.5393a(b), and there should be no efficiency design requirement in §60.5420a(b)(8).

B. The control efficiency determination for boilers and heaters is not practically feasible and the requirement should be removed.

Control efficiency for pneumatic pumps is a rather meaningless number because of the variable operating conditions associated with pumps and boilers/heaters.

Pumps and boilers/heaters can be operated seasonally or on an episodic, seasonal, or otherwise intermittent basis which may not compliment the need to continually combust an affected source's emissions. A boiler or process heater may be offline at the time pump discharge is sent to the heater or boiler for combustion. In other words, it can be "hit or miss" with respect to any single pump discharge being combusted. If a boiler or heater operates only seasonally but a pump is used year round, long periods of time will occur where combustion of the pump discharge will not occur. The intermittent nature of some well site process heaters and boilers makes designed control efficiency a meaningless data point since there could be frequent periods where emission reduction of pump discharge does not occur.

Failing a definition of control device under Subpart OOOOa that eliminates the treatment of boilers and process heaters as controls, at least with respect to control of pneumatic pumps emissions, EPA should at least clarify that operators are only required to specify the level of emission reduction expected when a given control device, heater, or boiler, is in normal operation.

C. Technical infeasibility determination for boilers and heaters should be simplified.

While the technical infeasibility issue is addressed in more detail in Item I.2 with respect to greenfield and brownfield sites, EPA should explicitly list in the rule those common situations that would meet the technical infeasibility determination.

If any of these situations were to occur at a site with an affected pneumatic pump, no certifications should be required to document why pump emissions are not being controlled by a device present onsite:

- Presence of boilers and process heaters not regularly operated (e.g. seasonally used equipment).
- Flare, heater, or boiler has a rated heat capacity that would be exceeded if the discharge of pump were to be sent to it.
- Presence of only a high pressure flare(s).
- Retro-fit to existing equipment may require manufacturer certification, nameplate update and/or void equipment / emissions warranty for purchased or rental equipment.
- Minimal space allotted for emission gas routing and heater/boiler system integration.

If the requirement to certify technical infeasibility remains, then, for the above situations, which will be some of the most common, operators should only be required to document and not certify the cause of the infeasibility. This approach would also be consistent with API's comments above that PE certifications should be removed from the rule and stayed pending reconsideration. As discussed in Item I.1, API believes the PE certification adds burden while not adding emission reductions and, as is the case with all required PE certifications in the rule, this requirement was not proposed originally and thus we were not provided proper notice and comment ability.

2. The compliance assurance requirements for a closed vent system (CVS) routing emissions from a pneumatic pump to a control device should be aligned to the requirements for storage vessels and not centrifugal and reciprocating compressors as currently finalized.

As noted in our December 4, 2015 comment letter on the proposed Subpart OOOOa, the compliance provisions related to the capturing of emissions from pneumatic pumps should be consistent with the requirements associated with closed vent systems for storage vessels and not those for wet seal centrifugal compressors and reciprocating compressors. Pneumatic pumps are most often located at well sites and small compressor stations that are more likely to have control devices installed to control emissions from storage vessels.

However, as finalized, the rule currently requires the same monitoring as required of affected centrifugal and reciprocating compressors – i.e. annual method 21 in addition to OGI monitoring for determination of fugitive leaks for closed vent systems for pneumatic pumps. These requirements are inappropriate, unduly burdensome, and duplicative. The costs for this requirement were not included in the cost analysis, and the negligible amount of emissions from pneumatic pumps does not justify this additional expense. The olfactory, visual, and auditory (OVA) inspection requirements associated with storage vessel closed vent systems are more appropriate.

The requirements for inspection and monitoring of closed vent systems associated with pneumatic pump affected sources should be moved from §60.5416a(a) & (b) (centrifugal and reciprocating compressors)[6] to §60.5416a(c) to be consistent with the requirements for affected storage vessels. Alternatively, EPA could simplify all closed vent system inspection and monitoring requirements to have all systems subject to the provisions of §60.5416a(c).

3. There should be a pathway to reduce LDAR survey frequency to annual for well sites and semi-annual for compressor stations.

In comments on the proposed Subpart OOOOa, API explained why a fixed annual frequency would be the appropriate frequency for well sites and compressor stations. Cost effectiveness determinations did not correctly capture costs and subsequent benefits. The model plant used for the cost effectiveness determination did not adequately reflect that most well sites are much smaller than the model plant used in the EPA's analysis, which results in misrepresentation of smaller sites in the cost effectiveness determination. New industry data collected by an API member company (See Attachment A), shows that leak rates can remain well below the target leak threshold of 1% that was proposed with a fixed annual survey program.

EPA should update the model plant basis to be more reflective of actual well sites and revise cost effectiveness since the original analysis was based on unrealistic prices and emission reduction potentials. EPA should also consider evaluating the monitoring data becoming available from various new state programs to better inform the basis of assumptions throughout the analysis. (See section 27.3 of API's December 4, 2015 comments.) At a minimum, EPA should only initially require semi-annual or quarterly surveys for 2 years and then allow annual surveys for sites that do not have leaking a significant number of leaking components.

[6] Note also that there is no reference in §60.5393a for the CVS provisions required in §60.5416a(a); only §60.5416a(b) is listed. This leaves confusion as to EPA's intent regarding whether §60.5416a(a) would apply to a CVS routing emissions from a pneumatic pump.

API recommends providing an optional threshold of six (6) leaking components to allow monitoring frequency to be reduced since six leaking components represents 1% of components in EPA's model plant for gas well sites. Note that with a six leaking component threshold, survey frequency is more stringent for sites equal to or larger than the model plant and less stringent for the smaller sites, which were not properly represented on the cost effectiveness determination.

4. There should be an exemption from LDAR requirements for new low production wells and a pathway to discontinue LDAR at new wells that become low production wells.

In the preamble of the rule proposal, EPA solicited comment on the air emissions associated with low production wells, and the relationship between production and fugitive emissions. Specifically, EPA was interested in 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 emissions 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.

While the amount of production through a particular facility does not <u>directly</u> impact the amount of fugitive emissions, the number of fugitive components at that facility can increase if additional equipment is added to handle an increase in production (for instance a new well brought online with an additional train of process equipment), and can decrease substantially as production declines if production equipment is either disconnected or removed from the site so that it may be utilized elsewhere or sold. Typically, stripper wells have decreased in production to the point where there may be minimum equipment on site compared to average higher production wells for which EPA's model plant was based. (Note: the average oil stripper well in the U.S. averages approximately 2 BOPD, even though one threshold for classification as a stripper well is 15 BOEP).

As indicated in Section 27.2.4 of our December 4, 2015 comments, sites with equipment configurations or component counts significantly less than EPA's model plants should be exempt from the LDAR requirements based on cost effectiveness. EPA is not correct in their Response to Comments (EPA-HQ-OAR-2010-0505-6983, Excerpt 17) that suggests the model plant cost analysis should equate to all well sites, even those with significantly fewer components, since there are larger well sites that have more components. The best system of emission reduction (BSER) is not based on a calculated average value, but rather it establishes a threshold limit where controlling a source above the threshold is considered cost effective and controlling a source below the threshold is not. One example of this is found in 40 CFR Part 60, subpart JJJJ where applicability and levels of control are linked directly to rated horsepower, which is generally proportional to potential emissions. There is a threshold (e.g. rated horsepower) where technology limits are cost effective and below which they are not. As communicated to the Agency previously, API continues to recommend EPA apply a similar approach for low production wells in regards to LDAR because the typical count of components at those facilities is substantially less than the EPA's model plant analysis.

In addition, low production sites typically have lower operating pressures than average high production sites. Most low production sites operate with a gas gathering system operating at relatively low pressures (<50 psig) because the depleted well cannot provide enough pressure to get into a typical gas gathering pressure of 125 to 200 psig. The number of fugitive components and operating pressure are the two variables that determine leak rates from fugitive components. While production rate does not directly affect the amount of fugitive emissions from a site, it is an appropriate surrogate in the case of low production wells because higher production sites typically have enough wellhead pressure to operate at the higher pressures needed to get into a 125 to 200 psig gas gathering system.

EPA should revise the rule to provide an exemption for low production wells [15 BOED (stripper well)] as requested in API's prior comments. API suggests low production wells be considered wells with < 15 barrels oil equivalent production per day (BOED), also known as stripper wells. Additionally, EPA should provide a mechanism to cease LDAR surveys when production from well sites drops below 15 BOED. The cessation of LDAR after production drops is analogous to the ability the rule provides to remove a control device after emissions from a storage vessel drop.

5. Oil wells should be exempt from the LDAR requirements.

Based on EPA's estimates from the rule proposal, LDAR requirements for oil well sites were not cost effective. Accordingly, API commented that oil wells should be exempt from the Subpart OOOOa LDAR requirements in Section 27.2.8 of our December 4, 2015 comments.

While finalizing the rule, EPA revised the model plant assumptions for oil well sites significantly. This is described in Section 4.2.2.3 of the Final Technical Support Document (TSD). As described in the TSD, EPA created two oil well site model plants, one representing oil well sites with < 300 GOR and one for sites with greater than 300 GOR. The less than 300 GOR oil well site model plant is essentially the same as the model plant proposed. However, for the greater than 300 GOR oil well site model plant, EPA arbitrarily added components to the site. EPA stated:

> "*To develop the model plant for oil well sites with a gas-to-oil ratio greater than 300 standard cubic feet of gas per stock barrel of oil (greater than 300 GOR), three meters/piping were added to the equipment counts included for the less than 300 GOR model plant to account for the handling of the natural gas from the well.*"

There are several problems with the approach EPA took in updating the model plant.

- EPA made significant changes to fundamental assumptions regarding the component counts. These changes resulted in large changes to the cost effectiveness values as the emissions per site more than doubled due to the change.
- EPA is assuming that an oil well model plant with greater than 300 GOR would look exactly like a gas well in terms of the numbers of components associated with metering and piping. In fact, the gas well site assumptions were used directly for the greater than 300 GOR oil well sites.
- EPA is treating "meters/piping" as if it is a single piece of equipment and scaling the number of "meters/piping" based on the assumed number of wells present. In reality, there are many cases where no gas metering occurs at a well site. Further, it is even more infrequent for there to be a need to add proportionally more piping or meters as more wells are brought on line at a given site. The sharing of equipment is a key benefit of multi-well sites.

EPA's updated analysis, indicates, that for oil wells greater than 300 GOR, the costs per ton of methane and per ton of VOC were 2 times higher than for gas wells. Further, for oil wells less than 300 GOR costs per ton were 4 ½ times higher than for gas wells. Therefore, at a minimum, EPA should exempt oil well sites less than 300 GOR from the leak detection and repair requirements, as control of these facilities is still not cost-effective.

6. The timing of LDAR Surveys should be updated to allow for integration into existing LDAR programs.

The final rule states that an initial survey must be completed within 60 days of start of production for a well site or within 60 days from startup or modification of a compressor station. Subsequent surveys then are to take place on a semiannual basis for wells sites and a quarterly basis for compressor stations. The implementation of LDAR programs is not trivial; there are numerous challenges to building a robust program. While API appreciates EPA's recognition of this by providing for a one-year phase in for the LDAR requirements, there remain challenges with the required timing of initial inspections. Given the significant distances between many oil and gas sites, the requirement to have an initial inspection within 60 days creates significant burden for very little benefit when the initial inspection could easily be rolled into the next periodic inspection for the other sources in that area. Furthermore, many sites are located in extremely cold climates in the intermountain west or Alaska that may not be reachable to do the LDAR surveys within 60 days (see also item immediately below).

API recommends EPA allow 180 days for the initial survey. It is noted that this timing is not expected to result in significantly more emissions. If a 180 day period were allowed, on average, half the sites would likely be surveyed at less than 90 days and half would likely be surveyed between 90 to 180 days.

7. The LDAR requirements must include adequate provisions to account for extreme weather in cold climates.

The temperatures on the Alaskan North Slope, and certain other areas throughout the country, are bitterly cold during winter months and adequate provisions must be considered in applying the LDAR provisions in the Subpart OOOOa.

A. The operations on the Alaskan North Slope should be categorically exempt from the LDAR requirements.

EPA set this precedent within Subpart OOOO and now Subpart OOOOa by allowing for an exemption from LDAR in §60.5401(e) and §60.5401a(e) for natural gas processing plants located on the Alaskan North slope. EPA should consider similar exemptions from LDAR for well sites and compressor stations since these operations experience the same harsh conditions.[7]

In the final Subpart OOOOa, the minimum requirement between the semi-annual surveys is 4 months for well sites. The semi-annual surveys on the Alaskan North slope could only be conducted in May/June and September/October due to sustained low winter time temperatures (approximately five consecutive months with average temperature below 0 degrees Fahrenheit). While EPA acknowledged that an exemption was needed for compressor stations and provided a waiver for quarters where the ambient temperatures are below 0 degrees Fahrenheit, the same was not done for well sites. EPA described the rational for this by assuming there would be no 6-month period where all months were below 0 degrees Fahrenheit average. The rule requires an OGI on newly affected sites within 60 days of completion, which is not practical on the Alaskan North Slope five months of the year. For example, if a well is completed at the end of November, an OGI would be required by the end of January. This would not be possible as the ambient temperatures in mid-November through mid-April are very rarely above 0 degrees Fahrenheit on the Alaskan North Slope. Moreover, the 30-day repair window does not accommodate the reality on the Alaska North Slope that parts (custom parts designed for Arctic environment) may be unavailable, and there is no delay of repair provision for this issue.

EPA should consider an exemption for operations on the Alaskan North Slope. At a minimum, EPA should allow for a waiver at well sites similar to the provisions provided for in §60.5397a(g)(5) for compressor stations and extend the initial survey frequency to 8 months (240 days) to adequately account for weather conditions in this region. Extension of the initial survey timing would allow for the survey to coincide with semi-annual survey frequencies. In addition, it would be appropriate to include as a reason for delay of repair, parts unavailability for the Alaska North Slope.

B. Inclement Weather Considerations for completing LDAR are necessary.

For other parts of the country in the Lower 48 that experience sustained inclement weather (Wyoming, North Dakota, Colorado, etc.), EPA should provide an additional extension of time to complete the initial and subsequent surveys due to possible road closures, accessibility of the site and safety of personnel. For example, it is common in states like Wyoming and North Dakota for a snow storm to cover the ground in multiple feet of snow, which would prevent access to many remote well site and compressor station locations. Extended periods of high winds are also common and similarly impact ability to complete surveys.

At a minimum, a 30 day extension should be granted to adequately handle unforeseen inclement weather events.

8. There should be a simple process for determining State Equivalency for the LDAR requirements at the State level; not just the process outlined in §60.5398a for Alternative Means of Emissions Limitations.

The Alternative Means of Emission Limitation (AMEL) process described in §60.5398a and §60.5402a are conceptually helpful, but the process appears to be limited in terms of true practical benefit. EPA's intent is not explicitly clear. For example, once an AMEL has been approved, can it be used by anyone operating in that particular state? While this should be the case, it is not clear. It is inefficient to have multiple operators petitioning for the same equivalency if all operators in a state are subject to the same state requirements. The inefficiency of individual operator petitions will lead to extensive delays of petition approval. EPA's language in the Subpart OOOOa seems to indicate that only owners/operators can apply; however, the potential for various trade groups to petition on behalf of its members in a state would avoid duplicative work by individual operators and burden on EPA. Additionally, under the proposed approach, it is not clear exactly what happens if the state subsequently revises its LDAR requirements. Would the AMEL become invalid? Would there be a grace period to request an update to the equivalency determination?

EPA should consider additional AMEL processes or provide guidance to reduce burden on operators and EPA. For example, EPA should consider allowing trade associations to petition on behalf of operators. At a minimum, EPA must clarify that upon approval of any request for a particular state, all operators in that state can immediately rely upon that equivalency determination.

9. The definition of modification for LDAR should only include wells that are hydraulically refractured in combination with the installation of new production equipment on site.

As mentioned in our December 4, 2015 comments regarding exemption of low production wells from LDAR, the amount of production, in and of itself, does not increase or decrease the amount of fugitive emissions emitted from a site with the relative same number of fugitive components and same approximate operating pressure. A well that is refractured typically does not require additional production equipment and does not typically operate at a pressure higher than before the refracturing since that pressure is set by the gas gathering system pressure. Therefore, as long as a significant piece of processing equipment is not constructed along with the refracture, there is no emissions increase and there is no "modification" as defined in CFR Part 60.2

API recommends that EPA make the following revisions:

- Revise the last sentence in §60.5365a(a): … *However, hydraulic refracturing of a well, <u>with the construction of additional permanent process equipment (storage vessel, separator, compressor, heater treater, or meter-run)</u>, constitutes a modification of the well site for purposes of paragraph (i)(3)(iii) of this section, regardless of affected facility status of the well itself.*
- Revise §60.5365a(i)(3)(iii): *A well at an existing well site is hydraulically refractured <u>and additional permanent process equipment is constructed (storage vessel, separator, compressor, heater treater, or meter-run)</u>.*

10. The digital photo/video requirements associated with LDAR provision in §60.5420a should be removed.

As documented in EPA's Response to Public Comment document (see EPA-HQ-OAR-2010-0505-6924), EPA responded to a request from the State of Arkansas seeking removal of the requirement to keep photograph records by stating: *"The date-stamped digital photograph serves as a record that someone performed a monitoring survey at the site. In the traditional LDAR scenario, the owner or operator tags all of the equipment that must be monitored, and when the Method 21 operator subsequently inspects the affected facility, the operator scans each component's tag and notes the component's instrument reading. This log serves as a documentation of the LDAR monitoring survey. In the fugitive emissions program under subpart OOOOa, we are not requiring owners and operators to document readings for each component, but we still need a compliance assurance mechanism to document that a monitoring survey was performed. We believe that keeping a digital photograph from the survey is a quick and easy way to fulfill this requirement."*

There are two major issues with EPA's logic in requiring these records. First, a digital photo technically only proves that someone was present on site and not the completion of an emission survey. Second, EPA continues to equate the sources covered under OOOOa with sources covered by "traditional LDAR". Chemical plants and refineries with traditional LDAR programs have full-time dedicated staff on site to manage the significant demands associated with running a "traditional LDAR" program. This is very different from un-manned remote production facilities.

API believes that records of repair and tagging of leaks in addition to general recordkeeping validates completion of surveys. EPA should remove the digital photo/video requirement for each OGI survey. At a minimum, EPA should modify the rule to make the photo requirement optional similar to that for REC recordkeeping, where the use of photographs is an alternative to other recordkeeping requirements.

11. Monitoring plan observation path and sitemap requirements under §60.5397a(d) are excessive and should be removed.

A company monitoring plan will cover all the relevant material needed for an effective LDAR program. While EPA eliminated the need for site-specific plans, the requirements for inclusion of site-specific information within the plan remain. There is no added benefit and there is significant added cost of developing hundreds and up to thousands of site-specific details to be included in monitoring plans.

The proposed requirement for site-specific monitoring plans, including the requirement to specify an observation 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 an observation 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.

Therefore, EPA should remove the requirements listed under §60.5397a(d)(1) and (2).

12. Delay of Repair Provisions require additional clarity.

In the Preamble of the final rule (FR 35858), EPA states:

> *We also agree that a complete well shutdown or a well shut-in may be necessary to repair certain components, such as components on the wellhead, and this could result in greater emissions than what would be emitted by the leaking component. The EPA does not agree that unavailability of supplies or custom parts is a justification for delaying repair (i.e., beyond the 30 days for repair provided in this final rule) since the operator can plan for accessible or obtaining the parts within 30 days after finding the fugitive emissions.*
>
> *Based on available information, it may be two years before a well is shut-in or shutdown. Therefore, to avoid the excess emissions (and cost) of prematurely forcing a shutdown, we are amending the rule to allow 2 years to fix a leak where it is determined to be technically infeasible*

> *to repair within 30 days; however, if an unscheduled or emergency vent blowdown, compressor station shutdown, well shutdown, or well shut-in occurs during the delay of repair period, the fugitive emissions components would need to be fixed at that time. The owner or operator will have to record the number and types of components that are placed on delay of repair and record an explanation for each delay of repair.*

§60.5397a(h)(2) states:

> *If the repair or replacement is technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair or replacement must be completed during the next compressor station shutdown, well shutdown, well shut-in, after an unscheduled, planned or emergency vent blowdown or within 2 years, whichever is earlier.*

This language was not in the proposed rule. The proposed rule for delay of repair was as follows:

> *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. (from page FR 56611)*

While API appreciates EPA's recognition that it was not appropriate to require a shutdown after a maximum of six (6) months as EPA originally proposed, the language finalized in Subpart OOOOa requires more clarity. Additional clarity is needed because the language in §60.5397a(h)(2) presumes that various shut down events and well shut-ins would necessarily result in the blow down of all equipment located on site (including the leaking component on delay of repair). This is not accurate. For example, during a well shut-in, some equipment on site may remain isolated, but under pressure (such as the line pressure leaving a well pad).

Further, there are commonly occurring, brief events that could be interpreted as well shutdowns or shut-ins, but should not be. These include: short interruptions in production to control reservoir pressure and manage well life such as plunger lift, pump rod, and manual intermittent well flow control. In addition to these events being very short, some are automated. The events are driven by the need to react to field conditions and, in most cases, they are not possible to predict and plan repairs of leaking components around.

While EPA recognizes that wellhead components may need leak repair, a leak in the master valve or connections below the master valve or at the bradenhead is a special situation that EPA needs to consider. Above the master valve of the Christmas tree, a leak can be repaired provided the master valve or other valve below or behind the leak doesn't leak when closed. Christmas trees are configured differently depending on the expected pressure and flow of the well, and high pressure trees may have dual master shut-in valves while low pressure trees may have only one. However, the lowest master valve is the isolation valve of last resort. If it is the source of the leak or the valve will not close properly to allow shut in of the well if needed to isolate it from the wellhead leak, or the bradenhead connection below the master valve is the source of the leak, a workover will most likely be needed to set a plug downhole to isolate the well so that a wellhead leak can be repaired. If the leak needing repair is small and not a safety concern, then mandating a leak repair within 2 years would not seem appropriate as a needed workover is a significant cost in addition to the cost of repairing or replacing the leaking component. For this situation, a delay of repair for a wellhead should be conditionally based on when a workover is needed for other downhole work and should not be subject to a 2 year limitation. A workover may be less than 2 years in some cases, but it can also be more.

In some cases, such as on the Alaska North Slope, the shutdown of a facility or a group of facilities in the winter can pose significant risks, including potentially the lack of primary electricity generation and space heating, and the potential for idle flow lines to gel or freeze. Backup diesel power generation is available only in limited capacities, and has higher emissions than gas turbines. In such extreme cases, bringing critical facilities back on line should not be delayed for relatively minor repairs for fugitive methane emissions. The rule should allow for such overriding considerations and not put the operator in a position of having to elect between regulatory compliance and prudent facility operations.

API proposes revising the language found at §60.5397a(h)(2) to read:

> *If the repair or replacement is technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown ~~or well shut-in~~, or would be unsafe to repair during operation of the unit, the following special provisions apply. For wellhead component repair or replacement that requires a workover for downhole work to isolate the well from the wellhead leak, repair must be made not later than the next scheduled workover to repair or re-condition the well. Otherwise, the repair or replacement must be completed during the next event requiring a blowdown of the equipment on which the leak was detected, with the shutdown lasting more than one day (e.g. compressor station shutdown, well shutdown, ~~well shut-in,~~ or after a ~~n unscheduled,~~ planned ~~or emergency vent~~ blowdown) or within 2 years, whichever is earlier.*

13. Issues with Compliance Demonstration Requirements for Combustion Devices and Flares Not Addressed.

EPA has failed to adequately respond to and understand concerns that API raised in our December 4, 2015 comments on the control device testing and monitoring compliance assurance related to measuring the volumetric flow rate as required under §60.5413a(b)(2) and under §60.18(f)(4) from storage vessels. Using Method 2, 2A, 2C, or 2D is not technically feasible[8].

EPA's response to comment, copied in below, did not fully address API's comments, nor did EPA cite aa specific meter a specific scenario where EPA has performed testing using Method 2, 2A, 2C, or 2D at a well pad. Specifically, EPA has not adequately shown resolution of the technical challenge of directly measuring the volume of material resulting from the flash of materials in storage vessels that occurs only when the separator dumps condensate to the storage vessel.

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 larger than ideal steady state conditions would dictate and makes flow measurement infeasible, particularly to meet the requirement to accurately measure such volume

[8] See Comments 12.1, 12.3, and 12.5 of API's December 4, 2015 comments on Subparts OOOO and OOOOa.

within ±2 percent. Industry has found no such flow meter available that can handle the variable flow which occurs with many of our combustion devices.

EPA has not provided industry with information of such a meter either. A turbine meter with a flow totalizer can be used, however if the upper or lower ranges are exceeded during the 1-hour test, the accuracy of the totalizer may be compromised. For a pitot tube, only a finite number of traverse sets can be collected during a 1-hour period, and can only be used if there is a constant flow, which is not the case with tank flash.

Aside from the technical challenges of obtaining an accurate flow reading for a performance test, there are safety risks for testing personnel due to the need to access the flow line feeding the control device while equipment is operation and flow to device is occurring. To adequately mitigate these risks, a facility shutdown, potentially including the shut-in of numerous wells would need to occur. It is not believed this was EPA's intent as these costs were not considered in rule development. Otherwise, a permanent flow meter would have to be installed, which EPA also did not include in the cost of the control device.

The following excerpt is from EPA's discussion of this in Response to Public Comments Document (Chapter 11):

> *Response: Concerning the portion of the comment related to auto-ignition devices, see response to DCN EPA-HQ-OAR-2010-0505-6808, Excerpt 17. Concerning the portion of the comment related to sonic flares, see response to DCN EPA-HQ-OAR-2010-0505-6846, Excerpt 1.*
>
> *The EPA agrees with the commenter on the ambiguity in regards to the requirements for flares used to control storage vessel emissions. We have revised the final rule to make our intent clear that flares are an acceptable control options under §60.5412(d) and §60.5412a(d) and to add applicable performance requirements for these flares.*
>
> *We are not providing an exemption for low-pressure flares to operate outside of the requirements of §60.18 during malfunction events. The restrictions in §60.18 ensure that the flare will achieve the desired destruction efficiency. The standard for destruction efficiency applies at all times, even during startup, shutdown, and malfunction. Allowing an exemption during these times provides no compliance assurance that the standard is achieved.*
>
> *We disagree that a performance test for flares is unnecessary or burdensome. The performance test ensures that the flare maintains a high destruction efficiency. Determining volumetric flowrate is a simple demonstration. While we acknowledge that engineering calculations can be a valuable tool for demonstrating compliance, actual measurements are necessary to demonstrate the accuracy of the engineering calculations. Actual measurements are also a useful tool for correlating and adjusting engineering calculations.*
>
> *We do not believe that there is a technical infeasibility issue in measuring the gas flow to the flare. While we believe that there will be a high enough flow to the flares to easily measure the flow as the performance test should only be performed at representative conditions, we note that the EPA flow methods are capable of handling low, intermittent and non-steady flow conditions.*

> *Finally, we note that the commenter previously stated that the EPA was incentivizing flare use by requiring measurement of gas flow on enclosed combustion devices, even though an enclosed combustor "yields higher destruction efficiencies than flares". The commenter further stated, "It is counterproductive for the environment to disadvantage enclosed combustors". While the EPA is not requiring a particular control device in Subpart OOOOa, in light of the commenters previous statement about not disadvantaging enclosed combustors, we do not believe that it is prudent to remove compliance demonstrations from flares when enclosed combustors are subject to such a requirement. All control devices should perform a demonstration that they are capable of achieving what they are required to achieve.*

Also, EPA has failed to justify why compliance for a MACT standard (NESHAP HH) is cost effective and necessary under an NSPS for small, dispersed, unmanned facilities in response to Comment 12.2.

The compliance demonstration requirements are still on a mass basis versus a volume basis which the standards are set at as API noted previously[9].

EPA had proposed revisions 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, in the final rule this value was changed to 275 ppmv without the opportunity to comment.

API requests that EPA review this issue further and revise the performance testing criteria accordingly. At a minimum, API requests that EPA provide language in the rule to allow for the option to petition for an alternative compliance demonstration for flares and non-certified enclosed combustors.

14. Requiring use of the Compliance and Emissions Data Reporting Interface (CEDRI) if EPA releases the electronic reporting form 90 days prior to the report due date is insufficient for compliance.

As mentioned in our December 4, 2015 comments, it is inappropriate for EPA to require electronic reporting under the Subpart OOOOa before the system is demonstrated capable of accommodating 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 versus 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. Operators need a significant amount of time to update internal systems to efficiently use CEDRI.

A poorly designed form without adequate testing is likely to result in additional burden to industry with no environmental benefit. Without a final CEDRI rule, more time may be needed to resolve issues in the final rule through the petition process. Finally, EPA cannot require industry to regularly monitor the EPA website for the availability of the CEDRI functionality required in the Subpart OOOOa.

EPA should amend the final rule language to formally allow for continuation of the initial reporting approaches from Subpart OOOO for three years to allow for rollout of the electronic reporting system. In addition, EPA should have a beta test period for CEDRI form before finalizing the form for industry

[9] Comment 12.4 of API's December 4, 2015 comments on Subparts OOOO and OOOOa.

use. At a minimum, EPA should amend the rule language to require CEDRI reporting only if the form is available for a minimum of 1 year prior to required reporting, not the 90 days as required in the current rule.

15. The definition of Capital Expenditure should be removed in §60.5430 of Subpart OOOO as it could be interpreted to imply retroactivity and the OOOOa procedure for calculating capital expenditure should be revised.

In its final rulemaking, EPA added a definition for "capital expenditure" to both Subpart OOOO and Subpart OOOOa claiming to "update[ ] the formula to reflect the calendar year that subpart OOOO was proposed, as well as specified that the B value for subpart OOOO is 4.5"[10]. The rule could be interpreted to impermissibly and retroactively alter the definition under Subpart OOOO. Under such an interpretation, EPA's revision to the Subpart OOOO definition, while cloaked as an update, would apply a legally impermissible retroactive calculation of "capital expenditures". EPA has not demonstrated that the CAA authorizes EPA to retroactively promulgate capital expenditure rules for evaluating modifications. See Bowen v. Georgetown University Hosp., 488 U.S. 204, 471 -72. (1988) ("Retroactivity is not favored in the law." "The power to require readjustments for the past is drastic."). Before EPA can make retroactive changes to Subpart OOOO, it must establish that the CAA allows for retroactive rulemaking. Id. ("it is axiomatic that an administrative agency's power to promulgate legislative regulations is limited to the authority delegated by Congress."). EPA has not done this. Moreover, EPA states that "our intent was not to recreate a retroactive requirement by revising subpart OOOO." [11]

Subpart OOOO previously did not separately define "capital expenditure" leaving the only applicable definitions as those included in 40 CFR § 60.2 and/or NSPS Subpart VV.[12] Prior to the rulemaking, (specifically from August 23, 2011 through September 18, 2015), if an operator of an onshore natural gas processing plant had a project at a process unit at the plant, which resulted in a physical or operational change that might be considered a modification, they had to rely upon the provisions associated with NSPS VV. A determination would have been made as to whether a facility change was a modification, i.e. resulted in a physical or operational change that caused an increase of emissions and required a capital expenditure. By changing the definition in Subpart OOOO, it could be interpreted that EPA appears to force operators to re-evaluate prior applicability determinations. Such a scenario would be unreasonable. In EPA's response to comments (section VI.H of preamble and Chapter 14 of Response to Public Comment document), this issue is lumped in with other reconsideration items and does not appear to have been considered adequately by itself.

Additionally, the formula provided by EPA in the definition for Capital Expenditure under Subpart OOOO does not work for a process unit constructed during 2011. For a project where capital expenditure was

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[10] 81 FR 35867.

[11] 81 FR 35866.

[12] Previously, for all terms not otherwise specifically defined, Subpart OOOO incorporated by reference the definitions found in the Clean Air Act, in Subpart A and Subpart VVa of 40 CFR Part 60. Subpart VVa's definition of a "capital expenditure" was stayed effective June 2, 2008. See 73 FR 31376 (June 2, 2008); and 73 FR 31379 (June 2, 2008). Thus, as NSPS Subpart KKK cross referenced NSPS Subpart VV, in order to analyze whether a "capital expenditure" occurred for purposes of determining whether a project was exempt from being a modification under 40 CFR § 60.14, an operator employed the terms as defined under 40 CFR § 60.2 and Subpart VV.

being considered, the formula results in the need to take the log(0), which mathematically can only be represented by negative infinity.

EPA must remove the definition of Capital Expenditure from Subpart OOOO to resolve the potential enforcement interpretation of its retroactive applicability, and to comply with Supreme Court rulings on impermissible retroactive application. Bowen, 488 U.S. 204; *Greene v. United States,* 376 U.S. 149, 160, 84 S.Ct. 615, 621–622, 11 L.Ed.2d 576 (1964); *Claridge Apartments Co. v. Commissioner,* 323 U.S. 141, 164, 65 S.Ct. 172, 185, 89 L.Ed. 139 (1944); *Miller v. United States,* 294 U.S. 435, 439, 55 S.Ct. 440, 441–442, 79 L.Ed. 977 (1935); *United States v. Magnolia Petroleum Co.,* 276 U.S. 160, 162–163, 48 S.Ct. 236, 237, 72 L.Ed. 509 (1928).

Further, API believes that the definition of Capital Expenditure (and the equation listed in OOOOa) is unrepresentative of current economic conditions. It was meant to model inflation in the late 1970s and early 1980s, as stated in EPA-FR-1984-Vol 49 No 105, P 22603.

API requests that EPA utilize a ratio of Consumer Price Indices (CPI), as noted in our original comments and as used in the "Civil Monetary Penalty Inflation Adjustment Rule" published in the Federal Register on July 1, 2016 and located at **http://federalregister.gov/a/2016-15411**.

Moving forward, the definition under Subpart OOOOa with our recommended changes will ensure consideration of the definition as we think EPA intended for determination of applicability to modifications.

16. EPA should clarify that coil tubing cleanouts and screenouts are not subject to the provisions in §60.5430a.

API submitted a letter to EPA on June 13, 2016 seeking clarification regarding "screenouts" and "coil tubing cleanouts". As EPA has previously acknowledged in its September 28, 2012 letter to API, there are necessary processes performed during hydraulic fracturing that are not associated with flowback following hydraulic fracturing and thus not subject to Subpart OOOO. With Subpart OOOOa, EPA must clarify that screenouts and coil tubing clean outs are not subject to the requirements in §60.5375a.

API is proposing to address this issue by adding clarification of the definition of "flowback" §60.5375a as noted below.

> *Flowback* means the process of allowing fluids and entrained solids to flow from a well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. The term flowback also means the fluids and entrained solids that emerge from a well during the flowback process. The flowback period begins when material introduced into the well during the treatment returns to the surface following hydraulic fracturing or refracturing. The flowback period ends when either the well is shut in and permanently disconnected from the flowback equipment or at the startup of production. The flowback period includes the initial flowback stage and the separation flowback stage. <u>Screenouts and coil tubing clean out activities on a well are not considered part of the flowback process.</u>

17. Additional Technical Corrections

A. §60.5393a(b)(3)(ii)

In §60.5393a(b)(3)(ii)there is reference to a paragraph that does not exist. API believes EPA intended for this section to reference (b)(3)(i) instead as follows:

> *"If you subsequently install a control device or have the ability to route to a process, you are no longer required to comply with paragraph ~~(b)(2)(i)~~ (b)(3)(i) of this section..."*

B. §60.5397a(d)(4)

> "Your plan must also include the written plan developed for all of the fugitive emission components designated as difficult-to-monitor in accordance with paragraph (g)(3)(i) of this section, and the written plan for fugitive emission components designated as unsafe-to-monitor in accordance with paragraph ~~(g)(3)(ii)~~ (g)(4)(ii) of this section."

C. Pneumatic Pump Affected Facilities Outside a Natural Gas Processing Plant

As explained in the preamble (81 FR 35850), EPA has decided to finalize pneumatic pump requirements only for well sites, and not for the gathering and boosting, and transmission and storage segments. This decision was reflected in the final rule by limiting the scope of pneumatic pump affected facilities to pumps "located at a well site", which is a change from the language in the 9/18/2015 proposed rule about pumps "not located at a natural gas processing plant." However, the phrase "not located at a natural gas processing plant" still remains in several paragraphs in the final rule, including: §§60.5410a(e)(2), (3), (4), and (5). This phrase should be replaced with "at a well site."

D. Fugitive Emissions - Timeframe for Resurvey

In the introductory paragraph §60.5397a(h)(3), a resurvey following the repair or replacement of a component is required to be conducted as soon possible, but no later than 30 days "after being repaired." However, §60.5397a(h)(3)(i) requires the resurvey be conducted within 30 days "of finding such fugitive emissions." To be consistent with the introductory paragraph, §60.5397a(h)(3)(i) should be revised as follows:

§60.5397a(h)(3)(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 within 30 days after being repaired ~~of finding such fugitive emissions~~.*

E. Table 3 Reference

Table 3 of Subpart OOOOa states that §60.8 applies with the explanation of "Performance testing is required for control devices used on storage vessels, centrifugal compressors and pneumatic pumps."

API believes that pneumatic pumps should be removed from this listing as control devices for pumps are not subject to performance testing.

F. Pump Closed Vent System Issues

As described in Item II.2. above, the compliance assurance requirements for a closed vent system (CVS) routing emissions from a pneumatic pump to a control device should be aligned to the requirements for storage vessels and not centrifugal and reciprocating compressors as currently finalized. Updating the rule language to reflect this will resolve API's primary issue.

However, the language and references under §60.5410a will require close review and updates as well to ensure the proper intent is reflected. For example, currently, under §60.5410a(e)(2), the rule references complying with the closed vent system requirements under §60.5411a(a) and (d). §60.5411a(a) includes pneumatic pumps in the list of applicable equipment. However, §60.5411a(d) refers to the PE certification requirements that appear to apply to storage vessels in §60.5411a(d)(1).

Separately, in §60.5410a(e)(5), the rule language repeats §60.5410a(e)(2) for control devices not able to achieve 95% control (§60.5393a(4)) but says the closed vent system must comply with §60.5411a(c) and §60.5411a(d). §60.5411a(c) only applies to storage vessels. Therefore, in the current rule, it appears that §60.5410a(e)(5) mistakenly references §60.5411a(c) instead of §60.5411a(a).

Again, API believes that pump closed vent system should be aligned with the requirements for storage vessels and not the requirements for affected compressors. The above inconsistencies in the current rule text are provided here to highlight the need to ensure complete and clear updates occur throughout Subpart OOOOa to reflect this change.

Attachment A
Leak Survey Data (Colorado & Barnett Shale)

2015 Colorado Reg 7 - Production Sites - AIMM Summary (Production sites, Annual Surveys (< 12 TPY))

LDAR INSPECTION AREA	COUNTY	TYPE OF FACILITY	Leaking Valves	Total Est. Valve Count per location	Total Leak % for valves (total leaks / total valves inspected area)	Leaking Connectors	Total Est. Connector Count per location	Total Leak % for Connectors (total leaks / total connectors inspected area)	Leaking Flanges	Total Est. Flange Count per location	Total Leak % for flanges (total leaks / total flanges inspected area)	Leaking Pump Seals	Total Pump Seal Count per location	Total Leak % for pumps (total leaks / total pumps inspected area)	Leaking PRD	Total Est. PRD Count per location	Total Leak % for PRDs (total leaks / total PRDs inspected area)	Type of Site	Totals sites inspected
Raton	Las Animas	Single Well Production	75	80	0.19%	41	220	0.038%	13	120	0.022%	0	1	0.0%	4	40	0.020%	Single Well Pads	490
Raton	Las Animas	Compressor Station	1	410	0.02%	14	250	0.400%	1	860	0.008%	0	5	0.00%	0	40	0.000%	Comp Station	14
Durango	La Plata	Single Well Production	214	80	1.76%	159	220	0.475%	16	120	0.088%	0	1	0.0%	2	40	0.033%	Single Well Pads	152

	Component total	Site Count	Leaker Count		Average Comp/site	Average Leakers/site	Average % Comp leaking
Single well pad component count	225890		133		461	0.3	0.06%
well count raton		490					
Comp station component count	21910		16		1565	1.1	0.07%
staiton count		14					
Single well pad component count	70072		391		461	2.6	0.56%
well count durango		152					
Total	317872	656	540				
% Leakers (all site types)	**0.17%**						

2015	Components	Leakers	% Leaking	Frequency Comments
Colorado	317,876	540	0.17%	Annual
Barnett Shale Production	20,768	159	0.77%	Annual voluntary
Barnett Shale Midstream	77,672	130	0.17%	Annual voluntary
Total	416,316	829	0.20%	

% Leakers	0.20%

Notes:

Barnett Shale Midstream is based on 28 sites and component count half of Longhorn at (0.5*5548 per site)
Barnett Shale Production is based on 176 sites inspected * 118
Colorado based on actual counts