Matthew Todd
Senior Policy Advisor

Regulatory and Scientific Affairs

1220 L Street, NW
Washington, DC 20005-4070
USA
Telephone 202-682-8319
Email toddm@api.org
www.api.org

December 17, 2018

The Honorable Andrew Wheeler, Acting Administrator
Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, DC 20460

Submitted to www.regulations.gov

Re: Docket ID No. EPA-HQ-OAR-2017-0483; EPA's "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration; Proposed Rule"; 83 Fed. Reg. 52056 (October 15, 2018)

Dear Acting Administrator Wheeler:

The American Petroleum Institute ("API") is pleased to submit the attached comments regarding EPA's reconsideration of the New Source Performance Standards ("NSPS") 40 C.F.R. Part 60 Subpart OOOOa, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Proposed Rule" at 83 Fed. Reg. 52056 (October 15, 2018).

API is the only national trade association representing all facets of the oil and natural gas industry, which supports 10.3 million U.S. jobs and nearly 8 percent of the U.S. economy. API's 620 members include large integrated companies as well as exploration and production, refining, marketing, pipeline, and marine businesses, and service and supply firms. They provide most of the nation's energy and are backed by a growing grassroots movement of more than 40 million Americans. Many of our members are directly impacted by the proposed amendments to the rule.

Throughout the development of the 2012 oil and gas NSPS rule and its amendments in 2016, API has maintained a constructive working relationship with EPA staff to provide operational expertise and emissions data to inform the developments of these important rules. During this time, our objective has remained the identification of cost-effective emission control requirements that reduce VOC emissions for new and modified sources and, as a co-benefit, also reduce methane emissions. Importantly, all oil and gas production emission sources that are covered by the previous 2012 and 2016 rules will continue to be effectively addressed. This approach, when combined with the leadership the industry has demonstrated to voluntarily reduce emissions from existing sources, has already proven effective in reducing emissions. Our industry has led the way in its pursuit of improved operations and keeping our product in the pipe, and the industry is incentivized to safely recover and capture methane as it is the primary component of natural gas.

Even as US oil and natural gas production has surged, methane emissions have declined significantly. For example, methane emissions from the natural gas industry have fallen 16 percent even as production increased by 50 percent since 1990. This is effectively a 45% reduction in the rate of emissions, further demonstrating industry's continued progress in minimizing emissions as we maximize efficiency in getting energy to the consumer. Methane emissions from hydraulically-fractured natural gas well completions have fallen more than 85 percent since 1990, and the increased use of natural gas to fuel the power sector has played the most significant role in achieving 30-year lows in carbon dioxide emissions from power generation that we see today. These trends are indicative of what our industry, when given the freedom to innovate, can achieve to improve the environment while protecting our nation's energy security. We fully expect that progress will continue.

API supports EPA's reconsideration of the rule and appreciates the proposed changes that provide additional clarity for our industry to maintain compliance. However, the proposed rule includes several missed opportunities and, in many circumstances, has increased the stringency of the rules without securing additional environmental benefit. Overly burdensome recordkeeping and reporting, overlapping regulatory requirements with state leak detection and repair programs, and a reinterpretation of several important aspects of the rule are all examples where further improvement is warranted to balance compliance assurance with securing emissions reductions.

There are significant capital investments and scientific studies underway to advance the development and use of new emission detection technologies; the proposed regulation that requires site-specific approval for each new technology will only stifle this positive development. We hope that EPA continues to significantly streamlines this process in the final rule. The rule also fails to reduce the burden of overlapping regulatory requirements that have no environmental benefit. While the agency agrees that many state leak detection and repair programs are equally effective, significant and duplicative recordkeeping and reporting remain. This is just regulatory burden without environmental benefits, and we encourage the agency to improve the recordkeeping and reporting requirements in the final rule.

We also encourage the EPA to recognize the value of the field data measurements that have been shared with the agency. API collected initial leak survey data during normal operations from more than 4,000 sites and representing more than 2 million components that demonstrates a much lower incidence of leaks when compared to the EPA estimates in the rule. However, the agency has dismissed this data due to hypothetical uncertainties that effectively undermines the credible advantages the use of optical gas imaging cameras provides to our industry by facilitating our ability to find and repair leaks. These findings should inform the final rule because they support an annual frequency as a cost-effective survey frequency at well sites and, importantly, demonstrate that the agency has significantly overestimated the emissions resulting from implementation of this rule as proposed.

In API's petition for reconsideration, we sought a reduction in the administrative burden to operators by revisiting the amount of records required to be maintained and reported for each leak detection survey. The oil and gas sector is unique in that thousands of newly affected sources will, year after year, compound the recordkeeping and reporting burden. However, in the proposed amendments, EPA has *increased* the recordkeeping and reporting requirements to operators without adequately justifying increased costs with respect to the administrative burden these proposed changes would require. The level of data required for recordkeeping and reporting within subpart OOOOa unnecessarily includes significantly more data points than other traditional LDAR programs with fewer affected sources.

API and its members recognize the importance of developing oil and gas resources responsibly, but there is no value to implementing duplicative and costly regulations with little or no environmental benefit. The combined technologies of hydraulic fracturing and horizontal drilling have elevated the United States to global prominence as an energy superpower. Because of the advanced application of these technologies, the United States is now the world's largest producer of oil and natural gas while, at the same time, emissions from the industry continue to decline. This positive trend will continue as many companies engage in multiple voluntary programs and individual efforts to further reduce emissions from oil and gas production. Industry's commitment to reduce emissions is exemplified by The Environmental Partnership, a program that has brought more than 50 of the nation's oil and gas producers together, both large and small and operating across the entire nation, to take concrete actions to reduce emissions. This energy revolution has helped to energize the U.S. economy by driving domestic investment in energy projects, creating jobs, and enhancing U.S. energy and national security interests. We encourage the agency to consider these positive trends and the important benefits this industry provides as you consider comments on the proposed rule.

Please contact me at toddm@api.org or 202-682-8319 with any additional questions regarding the content of this submittal.

Sincerely,

Matthew Todd

cc: Peter Tsirigotis, USEPA
David Cozzie, USEPA

API Comments on Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration, 83 Fed. Reg. 52056 (October 15, 2018) Docket ID: No. EPA-HQ-OAR-2017-0483

December 17, 2018

Table of Contents

List of Attachments

API's Comments on Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration Docket ID No. EPA-HQ-OAR-2017-0483

1.0 FUGITIVE EMISSIONS AT WELL SITES

1.1 ANNUAL LEAK SURVEY FREQUENCY FOR WELL SITES IS APPROPRIATE

API supports EPA's proposed revision to Subpart OOOOa to establish an annual frequency for leak surveys at new and modified well sites. An annual survey frequency is appropriate for the following reasons:

- EPA has mischaracterized the assumed number of leaking components per well site in their supporting document, citing 1.18% of components leaking (4 components per site) when the underlying emission factors used to estimate overall emissions assume higher leak rates.
- Data from API members surveys conducted under Subpart OOOOa as well as under state and voluntary programs show the average well site has significantly fewer leaking components nthan EPA assumed in its rulemaking; and thus, much lower baseline emissions prior to implementation of leak requirements.
- Given the much lower rate of leaks being found at well sites, during initial and subsequent leak surveys, there are limited environmental benefits to conducting leak surveys for well sites more often than annually.
- If EPA uses the best available data – data from the large number of surveys completed over the last few years – and reevaluates the benefits and costs from the Subpart OOOOa leak requirements, it will determine that there are less baseline fugitive emissions and, as a result, semi-annual leak surveys are not cost effective for well sites.

API members have been conducting leak surveys for new and modified well sites under Subpart OOOOa since the rule was effective in June 2017. Additionally, members have been conducting surveys under state and voluntary programs for much longer. These data, as well as data from other recent studies[1,2] indicate that the average facility has very few leaking components, even during the first leak survey.

[1] Lyon, et al. 2016. "Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites" (https://pubs.acs.org/doi/pdf/10.1021/acs.est.6b00705) – Aerial OGI surveys of 8220 well pads in seven basins identified 494 unique emissions sources at 327 well pads (< 4% of sites).

[2] "Lowering Emissions Across the Piceance," 2018 presentation by HRL Compliance Solutions and Colorado Oil and Gas Association – West Slope. Approximately 42,000 surveys at 2,200 sites found that 94.3% of leak surveys found no (0) leaks.

1.1.1 INDUSTRY DATA SHOWS THE NUMBER OF LEAKS IS LESS THAN THOSE ESTIMATED BY EPA

API previously initiated a data collection and analysis effort from member companies to determine how the implementation of leak monitoring and repair programs might further inform a reduced leak survey frequency. These data were provided to EPA in February 2018 and represented a range of operators across a range of geographies. The data represented observations from over 4,000 well sites, as compared to the 24 oil and gas sites upon which the emission factors in Table 2-4 of the 1995 Protocol for Equipment Leak Emission Estimates (EPA Leak Protocol) (EPA-453/R-95-017) are based. In response to this submittal, EPA provided a summary of its review of the data as part of the docket for this proposal (Docket EPA-HQ-OAR-2017-0483-0036). EPA did not objectively critique the submitted data. Rather than looking at the totality of the data and trends shown, EPA raised questions that could only be answered by a controlled experiment. API is including comments in response to EPA's analysis of the data as Attachment A of this document.

As a follow-up to the data analysis that API provided to EPA in early 2018, API undertook a recent effort to collect Subpart OOOOa data from member companies to understand how data collected under the rule might differ from the broader dataset previously provided to EPA. The reported Subpart OOOOa data include data from both the initial and second annual reporting period and show trends that are entirely consistent with API's earlier dataset and analysis. Specifically, the Subpart OOOOa data show:

- There are large number of sites that have no leaks (58% of initial well site surveys).
- The average number of leaking components per site is less than 2 components found leaking during the initial Subpart OOOOa survey and falls quickly to less than 1 leaking component found on average in subsequent surveys. These values are both below the 4 fugitive components that EPA assumed would require repair in each survey and even further below the number of leaks assumed in the EPA Leak Protocol Table 2-4 emission factors that were used to estimate emissions (See Figure 1 in Comment 1.1.3). In fact, nearly 92% of all surveys conducted across the 2 year period identified 4 or less leaking components per site.

Summary data and analysis of the Subpart OOOOa data from member companies is provided in Attachment B. While EPA previously expressed prior concern about certain aspects of the previous API survey data, API expects that providing these data developed from Subpart OOOOa surveys should adequately address any EPA concerns. The Subpart OOOOa data confirm that semi-annual leak monitoring provide limited incremental environmental benefit and support EPA's proposed annual survey frequency. API welcomes the opportunity to discuss these data further with EPA.

1.1.2 SUBPART OOOOA BASELINE FUGITIVE EMISSIONS ARE NOT BASED ON 1.18% OF LEAKING COMPONENTS AT THE MODEL PLANT

At the time of the original Subpart OOOOa rulemaking, EPA did not have adequate leak detection and repair data from well sites and compressor stations to develop baseline emission rates. Therefore, EPA relied upon the general oil and gas leak emission factors from the EPA Leak Protocol. Specifically, EPA applied emission factors in Table 2-4[3] to all components estimated within the model plant in order to quantify the baseline emissions in absence of a leak detection and repair program.

The above point is important because EPA and others have often cited that the Agency assumed a leak incidence rate of 1.18% for fugitive components in the analyses to support the development of Subpart OOOOa. EPA discusses this issue extensively in the preamble for the current proposed rulemaking (Section B.1). However, this statement is inaccurate with respect to the emission rates that EPA assumes in the rulemaking to estimate baseline emissions. EPA assumes 1.18% of components at the model plant are leaking with respect to the count of components that require repair. However, this value does not have any bearing on the baseline emissions nor quantified benefits from implementing leak detection and repair (LDAR) at well sites over time.

The figures in Chapter 5 of the EPA Leak Protocol can be used to determine the fraction of different component types that are assumed to be leaking, when applying the Table 2-4 factors to represent a population of components. This is demonstrated in Figures 5-16 through 5-34 of the EPA Leak Protocol. Each component type (connectors, flanges, open-ended lines, etc.) and each service have a different assumed leak fraction (or assumed number of leaking components) embedded within the average emission rate listed in Table 2-4. (See Attachment A of these comments for further discussion of an example figure from Chapter 5 of the EPA Leak Protocol.)

Using the figures and correlation equations within the EPA Leak Protocol, one can calculate that, for the EPA model facility used in the 2016 Subpart OOOOa rulemaking, EPA actually assumed between 1.6% and 2.5% of components at a model well site were leaking, depending on the leak threshold used to define the leak. The lower value represented an assumed 10,000 ppm Method 21 leak definition, and the higher value assumed a 500 ppm leak definition, which is the leak definition finalized within Subpart OOOOa.

We also note that the analysis EPA has done in the 2018 Subpart OOOOa proposal for pressure relief devices (PRDs) on controlled storage vessels follows a similar process to arrive at new emission factors based on newly available data. Similar to the Table 2-4 factors, the proposed emission factor represents yet another assumed fraction of components to be leaking for a particular component type that differs from the 1.18% value EPA cites.

1.1.3 EPA's Analysis Overestimates Baseline Well site Emissions and Emission Reductions from LDAR

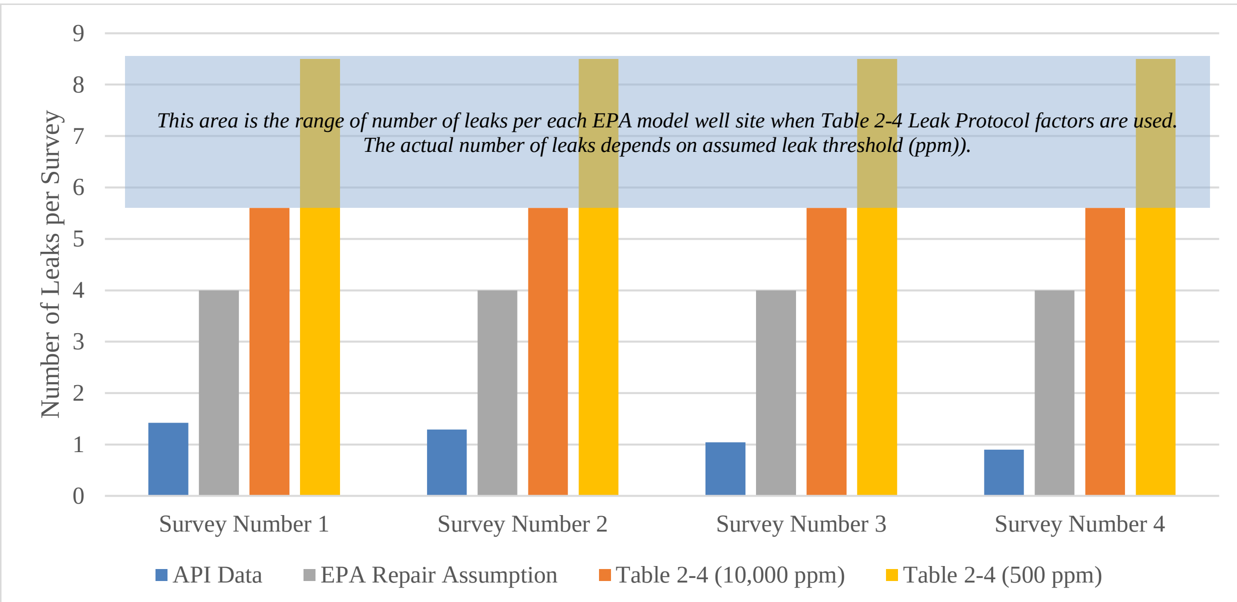
In addition to EPA relying upon the Leak Protocol emission factors that assume a higher percentage of components to be leaking than EPA's stated 1.18%, data from leak surveys conducted at regulated facilities indicate even fewer components are actually leaking. Figure 1 below illustrates the relative magnitude of the over-estimation. This figure was developed by normalizing the following data on a number of leaks per well site basis with the following assumptions:

3 The emission factors developed in Table 2-4 are based upon analysis of leak data from a limited number of facilities using Method 21. Specifically, the protocol is based on only a total of 24 oil and gas sites, as noted on page C-14 of the EPA Leak Protocol.

- Scaled EPA's 1.18% (or 4 leaking component) assumption to the percentage range (1.6% to 2.5%) behind the EPA Leak Protocol Table 2-4 values to estimate the average number of components expected to be leaking.
- Plotted data from API member company Subpart OOOOa surveys showing actual numbers of leaks found during semi-annual surveys.

It is clear that EPA's assumed number of leaking components, and by direct extension, the estimated amount of fugitive emissions are significant overestimates – by a factor of over 2.5 to up to 4 times.

Figure 1. Comparison of Actual Leaks Observed under Subpart OOOOa vs. EPA Model Plant Data Assumptions



1.1.4 Limited Forgone Emissions Impact

As part of the proposed rulemaking, EPA estimated the forgone emission reductions associated with impacts of the proposed changes, if finalized. The only forgone emission reductions from this proposal are expected to be from semi-annual leak surveys moving to annual leak surveys. Even with EPA's overestimation of emissions from fugitives and, thus an overestimate of benefits from implementing LDAR requirement, the following benefits are still realized:

- *Relative to only reductions from Subpart OOOOa leak provisions* – EPA estimates indicate that approximately 77-78% of LDAR reductions relative to the benefits from the 2016 Subpart OOOOa rule provisions will still be realized after accounting for state rules that are providing Subpart OOOOa like LDAR benefits (OH, PA, CA, CO, WY in EPA's analysis).
- *Relative to Reductions from all rule provisions* – EPA estimates indicate that approximately 85-87% of the reductions relative to the 2016 Subpart rule will still be realized after accounting for state rules that are providing Subpart OOOOa-like LDAR benefits.

The above statements are important as there are many who are referring to this proposed rulemaking as a major regulatory rollback or action that will result in significant emissions increases. This is inaccurate even with EPA's overestimates. When one accounts for the lower actual mass of reductions that are occurring through implementation of the leak provision, the amount of forgone benefits are even lower.

1.2 LOW PRODUCTION WELL SITES

API endorses the more detailed comments of IPAA and provides the following additional comments.

1. EPA should exempt low production well sites as originally proposed in 2015. As API has stated in prior comments, low production well sites typically have less equipment located on the well site and, therefore, less sources that could result in fugitive emissions. Given that there are no comprehensive studies indicate that low production well sites would have a higher fraction of components leaking than other well sites, it is expected that low production well sites, on average, will have lower emissions than other well sites. The IPAA comments further discuss the issues associated with EPA's reliance on data from a Barnett Shale study to represent low production wells in the Subpart OOOOa rulemaking process.
2. Furthermore, while the production rate does not directly impact the number of fugitive emissions from a site, it can be an appropriate surrogate for correlation in this context. Low production well sites typically operate at reduced operating pressures (i.e., often less than 100 psig) when compared to average production sites.
3. All well sites will eventually become low production well sites. Therefore, Subpart OOOOa affected well sites that become low production well sites should have a pathway to cease or reduce monitoring frequency following 12 consecutive months demonstrating that the production rate has dropped below 15 barrel of oil equivalent (boe) per day after startup of production. At a minimum, EPA should allow for a well that averages less than 15 boe per day over its first (or any) year of operation to immediately cease leak surveys or, if appropriate, reduce frequency.
4. API appreciates that EPA is proposing to include the standard cubic feet per barrel (scf/bbl) of oil ratio in the rule but, API suggests that EPA use the IRS Tax Code definition for boe of 6,000 scf/bbl.

Recommendation:

EPA should exempt low production well sites, as originally proposed in 2015, and allow for a pathway for well sites that become low production well sites due to production decline to reduce or cease monitoring. The determination should allow for demonstrating that the production rate has dropped below 15 barrel of oil equivalent (boe) per day over 12 consecutive months and reference the IRS Tax Code for boe which is 6,000 scf/bbl.

1.2.1 ADDITIONAL RECORDKEEPING AND REPORTING FOR LOW PRODUCTION WELLS

Requiring documentation that a well site meets the criteria of a low production well is appropriate. However, companies should only identify sites within the annual report as low production and not be required to report the production rate determination itself, as proposed in § 60.5420a(b)(7)(i)(E).

Providing identification of this designation should provide appropriate compliance assurance for these well sites. All records can be made available upon request by the Administrator, as necessary, for further review. If EPA were to revisit the exemption for low production well sites as originally proposed, documentation of the production determination including the methodology should be sufficient. No reporting of these well sites should be required.

In addition, there are typographical errors proposed within §60.5420a(c)(15)(iii) since we do not believe it was EPA's intent to require all well sites to document and report production values. The paragraph should refer to biennial monitoring based on the current proposed language, and the cross-reference should be reviewed to correctly refer to the appropriate paragraph (i.e. (g)(1)(ii)), as currently proposed.

Recommendation:

EPA should reduce administrative burden associated with low production wells by requiring documentation of the production rate determination as a recordkeeping requirement only.

EPA should review typographical errors to check for cross-reference issues (e.g. frequency cited in § 60.5420a(c)(15)(iii)).

1.2.2 REQUEST REMOVAL OF "NON-LOW PRODUCTION" DESCRIPTOR FOR LEAK DETECTION APPLICABILITY AND THE ASSOCIATED RECORDKEEPING AND REPORTING OF PRODUCTION VALUES

EPA has introduced the concept of a "non-low production" well for reference to and applicability of the fugitive emission requirements for new and modified locations. This descriptor is unnecessary and should be removed. Reference to and definition of "low production" well site establishes criteria for a subset of production well sites as a threshold less than 15 barrels of oil equivalent per day. It should be inferred that if this criteria is not met, then the well site does not meet this definition and is assumed to produce more than 15 barrels of oil equivalent per day.

Recommendation:

Remove the "non-low production" descriptor from the rule language since usage of the term is unnecessary.

1.3 THE PROPOSED CLARIFICATIONS TO THE DEFINITION OF WELL SITE ARE APPROPRIATE.

API supports EPA's proposed clarification to the definition of well site in § 60.5430a as it pertains to equipment owned and operated by a third-party operator at well sites and Class II disposal wells. We also support the proposed definitions of *"custody meter"* and *"custody meter assembly."* In addition to exempting meter assemblies at well sites and Class II disposal wells, we also request EPA provide a similar exemption for meter assemblies owned and operated by third parties located at compressor stations and also exempt non-hazardous Class I wells for similar reasons noted.

- *Third party owned and operated equipment at well sites*: The clarification to exclude meter assemblies from the fugitive emissions standards was necessary and will alleviate legal and logistical issues that arose with compliance with Subpart OOOOa for the small number of components, as API stated in previous comments to the Agency (see August 8, 2017). Meters used in this capacity are calibrated regularly, and any leaks would be detected at the time of calibration.

- *Third party owned and operated equipment at compressor stations:* The same exemption should apply to custody meter assemblies at compressor stations for the same legal and logistical reasons noted for well sites. The same language provided for well sites would be appropriate to include for compressor stations to account for the correct components.
- *Class II Wells:* The proposed definition and exemption for Class II disposal wells and disposal facilities is appropriate. As EPA stated in the preamble, the EPA had not considered these types of wells during the development of the fugitive standards in the 2016 Subpart OOOOa. This clarification alleviates confusion to the regulated community. These wells and facilities handle produced water that has already been physically treated to remove hydrocarbon and natural gas prior to the arrival at the facility to avoid loss of revenue. Equipment and components would primarily be in water service and would not directly compare to EPA's model plant analysis accounted for in the technical support documentation.
- *Non Hazardous Class I Wells:* In addition to exempting Class II disposal wells, we also request EPA exempt non-hazardous Class I wells for similar reasons noted. Like Class II disposal wells, non-hazardous Class I disposal wells were not considered during the development of the fugitive emission standards in the 2016 Subpart OOOOa. Class I disposal wells are regulated by the EPA (https://www.epa.gov/uic) and accept industrial waste, which includes Class II waste. Non-hazardous Class I wastes are required to be sampled for laboratory analysis according to their EPA permits.

While it is clear that these components will be excluded from Subpart OOOOa requirements for sources constructed after the October 15, 2018 publication date of the proposed rule (see 42 U.S.C. § 7411(a)(2)), API requests confirmation that affected facilities with the now-excluded components that have been subject to the 2016 version of Subpart OOOOa will no longer be required to comply with Subpart OOOOa requirements for those components once the rule is finalized. Confirming this in the final rule will avoid unnecessary uncertainty and is fully consistent with the rationale EPA has provided for amending the definition of well site.

Recommendation:

EPA should maintain the proposed clarification to the definition of well site in § 60.5430a as it pertains to equipment owned and operated by a third-party operator at well sites and Class II disposal wells and should maintain the proposed definitions of "custody meter" and "custody meter assembly."

In addition to exempting meter assemblies at well sites and Class II disposal wells, EPA should also provide a similar exemption for meter assemblies owned and operated by third parties located at compressor stations. EPA should also exempt non-hazardous Class I disposal wells in addition to Class II wells.

EPA must also provide confirmation that affected facilities with the now-excluded components that have been subject to the 2016 version of Subpart OOOOa will no longer be required to comply with Subpart OOOOa requirements for those components once the rule is finalized.

1.4 MAJOR PRODUCTION AND PROCESSING EQUIPMENT SHOULD NOT INCLUDE REFERENCE TO ANCILLARY EQUIPMENT SUCH AS PNEUMATIC PUMPS AND CONTROLLERS

API supports the concept EPA introduced for classifying major production equipment for purposes of determining whether a well-site facility is considered a wellhead-only facility and the provision that monitoring can cease when the major production equipment is removed. However, the definition of major production and processing equipment proposed by EPA includes reference to smaller auxiliary type equipment including pneumatic pumps and controllers. Pneumatic pumps and controllers should not be considered major equipment for purposes of determining applicability of the fugitive emission requirements, especially given their status as separate affected facilities under Subpart OOOOa. These small ancillary equipment do not contain a significant number of components, if any, and have limited potential to emit fugitive leaks. Therefore, a well site containing only a wellhead and a small chemical injection pump would have similar number of components as a site containing only a wellhead, which EPA has established as not cost-effective. Since the equipment is designed to vent, EPA has appropriately not included the pneumatic equipment within the definition of fugitive components, and this equipment would be excluded from the fugitive emission requirements directly.

Many wells have an emergency shutdown valve that is controlled by a pneumatic controller, which would make this new definition of a wellhead-only facility obsolete in practical application. While we agree the leak detection requirements should target sites that contain large permanent process equipment (condensate or crude oil storage vessels, separators, centrifugal or reciprocating natural gas compressors, dehydration units, or heater treaters) that have more fugitive components, we suggest EPA eliminate reference to auxiliary equipment (pneumatic pumps and pneumatic controllers) within the new definition. It is overly burdensome to broadly require LDAR programs at sites with only minimal supplemental equipment that would result in minimal, if any, emission reductions.

API also requests that EPA further clarify the definition by making “compressors” specific to centrifugal or reciprocating natural gas compressors within the definition.

Recommendation:

Pneumatic pumps and controllers should not be considered major production equipment since their inclusion makes the leak survey exemption obsolete. EPA should also further clarify the definition of major production equipment to add a descriptor to make compressors specific to centrifugal or reciprocating natural gas compressors.

1.5 MODIFICATION

1.5.1 MODIFICATION TO WELL SITES

EPA continues to define a modification to well site through identification of events that can result in an increase in production (i.e., drilling a new well, hydraulic fracturing a well, or hydraulic refracturing a well. These events, in and of themselves, should not be considered a modification. These actions do not necessarily increase the number of fugitive components at a well site, which could increase fugitive emissions at a site. There are a couple of primary considerations that should be made when analyzing whether an NSPS modification has occurred:

1. *Has the change resulted in an emission increase?* Consistent with the definition of modification for NSPS at 40 C.F.R. § 60.14[4], one would conclude there has not been a modification simply if a well is fractured or refractured because fugitive emissions are estimated based on EPA supported emission factors that consider only the number and type of components present at a facility. Therefore, if there is not an increase in the number of components, there would be no calculated emission rate increase from the collection of fugitive components and thus, no modification. More specifically, changes to flow or pressure are not factors in the emission estimate. It is noted that this same issue applies to fugitive components at other locations historically subject to LDAR (e.g., refineries, chemical plants, natural gas processing plants) and for those sites, changes to operating pressure or flow are not triggers for modification. Components could be brought into LDAR if there are significant changes to the composition of material (e.g., switch from < 10% VOC to > 10% VOC service), but not due to operating flow or pressure.
2. *What is the appropriate comparison when assessing an hourly emission rate increase?* Notwithstanding the issues noted immediately above about how fugitive emission rates are calculated, even if one were to consider EPA's argument in the preamble that an increase in flow and/or pressure results in emission increases following a hydraulic fracturing or refracturing event, one should look further back in time than just the moment prior to the operation on the well to determine if the collection of fugitive components experienced a change that increases the hourly emission rate relative to ANY hour in the past operation of collection of fugitive

[4] § 60.14 Modification.
(a) Except as provided under paragraphs (e) and (f) of this section, any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. 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.
(b) Emission rate shall be expressed as kg/hr of any pollutant discharged into the atmosphere for which a standard is applicable. The Administrator shall use the following to determine emission rate:
(1) Emission factors as specified in the latest issue of "Compilation of Air Pollutant Emission Factors," EPA Publication No. AP-42, or other emission factors determined by the Administrator to be superior to AP-42 emission factors, in cases where utilization of emission factors demonstrates that the emission level resulting from the physical or operational change will either clearly increase or clearly not increase.
(2) Material balances, continuous monitor data, or manual emission tests in cases where utilization of emission factors as referenced in paragraph (b)(1) of this section does not demonstrate to the Administrator's satisfaction whether the emission level resulting from the physical or operational change will either clearly increase or clearly not increase, or where an owner or operator demonstrates to the Administrator's satisfaction that there are reasonable grounds to dispute the result obtained by the Administrator utilizing emission factors as referenced in paragraph (b)(1) of this section. When the emission rate is based on results from manual emission tests or continuous monitoring systems, the procedures specified in appendix C of this part shall be used to determine whether an increase in emission rate has occurred. Tests shall be conducted under such conditions as the Administrator shall specify to the owner or operator based on representative performance of the facility. At least three valid test runs must be conducted before and at least three after the physical or operational change. All operating parameters which may affect emissions must be held constant to the maximum feasible degree for all test runs.

> components, including start of production. EPA's definition of modification ignores this important point that has been used to determine whether a modification has occurred under other NSPS rules for years.

API continues to maintain that the amount of production, in and of itself, does not increase nor decrease the amount of fugitive emissions emitted from a site with the same number of fugitive components and same approximate operating pressure[5]. For this scenario, an increase in the number of the fugitive emission components is the only modification that could increase the calculated fugitive emissions. Therefore, as long as major production equipment is not constructed along with the well activities listed (well is drilled, hydraulically fractured, or hydraulically refractured), there is no emissions increase and there is no "modification" as defined in § 60.14.

In the preamble to the proposed rule, EPA provides three justifications for its determination that refracturing a well at an existing well site constitutes a modification of the source pursuant to the Clean Air Act (CAA or "the Act") and EPA's modification rules. 83 Fed. Reg. at 52072-73. In the third of these justifications, EPA states that, even when refracturing does not result in additional equipment at an existing well site, refracturing should nonetheless be deemed a modification because:

> *"it is possible for increased throughput to these controlled storage vessels at a well site to exceed the design capacity of the vapor control system, which may result in additional emissions from storage vessel thief hatches or other openings."*

Id. at 52073. This rationale does not offer a sufficient basis for concluding that a modification has taken place and should be rejected by EPA as a basis for reaching such a conclusion in the final rule.

Modification is defined in Section 111 of the CAA (Section 111) as

> *"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."*

42 U.S.C. § 7411(a)(4) *(emphasis added).* EPA's third justification does not pass the statutory test for a modification. EPA's own words demonstrate that an increase in throughput causing an exceedance of a vapor control system design capacity is only "*possible*" and that such an exceedance only "*may* result in additional emissions." 83 Fed. Reg. at 52703 (emphasis added). If there is any possibility, even a remote one, that emissions will not increase (which EPA concedes is the case here), EPA cannot by blanket rule determine that a change will constitute a "modification" under the CAA.

Recommendation:

API requests that EPA update the rule language regarding modifications such that well site is considered modified if an operator drills a new well, hydraulic fractures a well, or hydraulic refractures a well and additional permanent process equipment is added to the site.

[5] See Attachment C for further discussion regarding how pressure is controlled at well sites such that operating pressure for surface equipment and piping does not generally increase due to changes in well head pressure.

1.5.2 MODIFICATION TO CENTRAL TANK BATTERIES

EPA should not finalize the proposed language that a central tank battery is considered modified for the purposes of the Subpart OOOOa leak provisions when "major production equipment" is removed at the separate surface well site such that it becomes wellhead only. Similar to the above discussion of modification of a well site, the simple act of removing surface equipment at a well site feeding a tank battery does not meet the statutory definition of modification. Without a change to the number of components at the tank battery, there would be no calculated emission rate increase. Further, while API does not agree with EPA's position on the impact of flow and pressure on fugitive emissions, even if one accepted EPA's position, EPA must still consider all aspects of this situation. That is, if a well site's production has declined so much that equipment has been removed and it is now a wellhead-only site, then it is highly likely that the total flow to the tank battery has not increased over a level it had experienced in the past and thus, would not see an emission increase relative to that prior level.

Even if EPA holds that there is a small, albeit unquantifiable, increase in emissions at a tank battery when a well feeding it removes some of its production equipment, API notes that the general provisions found under 40 CFR § 60.14 (e)(2) would address this situation. 40 CFR § 60.14 (e)(2) states:

> *(e) The following shall not, by themselves, be considered modifications under this part:*
>
> ...
>
> *(2) An increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility.*

In the situation of removing "major production equipment" from a well site feeding a central tank battery, there would be no capital expenditure at the well site and certainly none at the central tank battery facility.

Further, EPA's action to try to subject more tank batteries to Subpart OOOOa could prove to be a disincentive to operators with respect to the consolidation of equipment from wells that would actually reduce footprint and minimize emissions. When well sites become wellhead-only facilities, there is a reduction in the overall number of fugitive components. That is, the components do not move to the central tank battery. The central tank battery should only become subject to the leak provisions if major equipment is added to the central tank battery.

Recommendation:

A central tank battery should only become subject to the leak provisions if major production equipment (condensate or crude oil storage vessels, separators, centrifugal or reciprocating natural gas compressors, dehydration units, or heater treaters) are added to the central tank battery following one of the activities in § 60.5365a(i)(3)(i)-(iii) at a well site feeding the tank battery. EPA should not finalize the language proposed that triggers modification at tank battery after removal of major equipment at a separate wellsite.

1.6 COLD WEATHER TECHNICAL LIMITATIONS

1.6.1 API SUPPORTS PROVISIONS FOR ALASKAN NORTH SLOPE AS PROPOSED

We support EPA extending the timeframe for conducting the initial monitoring for all well site and compressor stations located on the Alaskan North Slope. As EPA stated in the preamble 83 Fed. Reg. at

52071, the requirements were warranted due to the area's extreme cold temperature, which is below the temperatures at which the monitoring instruments are designed to operate for approximately half of a year

1.6.2 API Conditionally Supports the Removal of Waiver at § 60.5397a(g)(5)

The removal of the waiver for cold climates is adequate as long as EPA maintains the frequencies proposed in the reconsideration as annual for well sites and at least semi-annual (between 4-6 months) for compressor stations. If these minimum frequencies are not finalized, the waiver at § 60.5397a(g)(5) must be reinstated to account for inclement weather and other harsh conditions that would cause safety issues for personnel or for when temperatures may be below those approved for use of the OGI camera.

2.0 FUGITIVE EMISSIONS AT COMPRESSOR STATIONS.

2.1 EPA SHOULD REDUCE THE SURVEY FREQUENCY AT COMPRESSOR STATIONS AND COMPRESSORS SHOULD NOT BE REQUIRED TO BE SURVEYED IN OPERATING MODE AT LEAST ONCE PER YEAR

API supports the comments submitted by GPA Midstream regarding the appropriate survey frequency for compressor stations. API does not support the proposed rule change that compressors must be surveyed in operating mode at least once per year but rather believes EPA should require operators to conduct surveys with facility operations as they are found when the survey is conducted. The proposed requirement is inappropriate for the following reasons:

- The requirement to ensure engines are surveyed in operating mode will result in situations where an engine will be brought on line just to enable an LDAR survey. This will add a significant logistical burden on operators as load on compressor engines can be unpredictable and may go down without notice just prior to a scheduled LDAR survey.
- The act of starting up and then shutting down (and potentially blowing down) a compressor engine that would not otherwise be required to operate is expected to result in more emissions than might be mitigated by any leak(s) identified in the process of the survey.
- Based on experience conducting 40 CFR Part 98 Subpart W required surveys for transmission compressor stations, it is expected that EPA's proposed requirement will result in the need for multiple survey trips in order to survey all compressors. EPA did not consider the costs for multiple trips when determining cost effectiveness for conducting leak surveys.

Recommendation:

API recommends EPA reduce the survey frequency and that operators conduct leak surveys with facility operations as they are found when the survey is conducted.

2.2 Modification to Compressor Stations – EPA Should Edit Rule Text to Address Vapor Recovery Units (VRUs)

With respect to VRUs, API appreciates the clarification EPA provided (83 Fed. Reg. at 52074), but we ask EPA to add regulatory language to confirm this interpretation that clarifies that a modification is triggered when an additional compressor is added for the compression of natural gas and that the addition of a VRU compressor was not intended to trigger the leak detection requirements.

3.0 SIMPLIFICATION OF THE LEAK MONITORING PLAN REQUIREMENTS

3.1 THE SITEMAP AND OBSERVATION PATH REQUIREMENTS SHOULD BE DELETED OR MODIFIED BECAUSE THEY ARE OVERLY PRESCRIPTIVE AND DO NOT BEAR A RATIONAL RELATIONSHIP TO THE EMISSIONS REDUCTIONS SOUGHT TO BE ACHIEVED.

API opposes the sitemap and observation path requirements in Subpart OOOOa because these requirements depart from the performance standard principles underlying Section 111 of the CAA in that they unreasonably restrict how industry achieves compliance with fugitive emissions monitoring. This prescriptiveness further has the effect of unnecessarily creating potential violations of the regulations (which EPA describes as deviations, defined as failure to meet rule requirements), even where the required surveys were properly conducted. These burdensome requirements are not only costly and onerous, they also fail to advance EPA's objectives beyond what a performance-based metric would achieve and, for these reasons, do not withstand scrutiny.

API requests that EPA simplify the monitoring plan provisions as follows:

- Remove the sitemap and observation path requirements and replace with a performance objective requiring all regulated components be monitored with the OGI equipment, without prescribing the way that this be achieved within the monitoring plan.

3.1.1 MONITORING PLAN SITEMAP AND OBSERVATION PATH REQUIREMENTS – AND THE RELATED REPORTING AND RECORDKEEPING – ARE OVERLY PRESCRIPTIVE AND UNREASONABLE

EPA's sitemap and observation path requirements should be stricken, or at the very least, modified, because EPA has failed to either (i) provide sufficient reasoning in support of its rationale for these requirements, or (ii) adequately address industry concern over the burdensome nature of strict compliance with them (and consequences of characterizing departures as "deviations"). It is an axiom of administrative law that an agency's explanation of the basis for its decision must include a 'rational connection between the facts found and the choice made.' " *Bowen v. Am. Hosp. Ass'n*, 476 U.S. 610, 626 (1986) (quoting *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983)). Accordingly, EPA must respond with providing such explanation or change the rule in such a way that meets its objectives and allows industry flexibility in meeting them as well.

As the proposed rule stands now, its requirements and EPA's supporting statements exemplify rulemaking requirements that are not rationally connected to the agency's stated goal and that run fundamentally contrary to the performance standard approach embodied in Section 111 of CAA. At its core, Section 111 directs EPA to issue performance standards but allows affected owners/operators to decide how to meet them. EPA has traditionally recognized that "[g]enerally, the EPA does not prescribe a particular technological system that must be used to comply with a standard of performance. Rather, sources generally may select any measure or combination of measures that will achieve the emissions level of the standard."[6] While the work practice provisions may be somewhat more specific given the nature of a work practice, the base performance standard approach remains and requires that EPA not impose requirements that are unnecessary or not rationally related to emission reduction. In this case, the observation path requirements are inefficient and provide no greater compliance assurance than a simple statement directing that all regulated components must be observed during the monitoring survey.

3.1.2 A *SINGLE* DEFINED OBSERVATION PATH IS INEFFICIENT AND COSTLY FOR AFFECTED INDUSTRY, AND PROVIDES NO GREATER COMPLIANCE ASSURANCE.

As EPA makes clear in the June 2016 final rule preamble statement, the fundamental goal of its "observation path" requirement is to ensure that all of the regulated components are reviewed with the OGI instrument. That goal can be met in any number of ways, and EPA's selection of a defined "observation path" deprives companies of flexibility in achieving the performance requirement to observe the regulated components and also manufactures potential violations by requiring a particular path to be followed even if another pathway would not only ensure that all of the regulated components are reviewed but prevent a modified approach that results in a more effective survey. Such an outcome is the very definition of arbitrary and capricious rulemaking.

The single defined observation path also fails to take into account the sequence of viewing fugitive components. EPA provides no reason why a different route (or even the same route in a different order or with a break in-between), would not meet its goal. In short, the June 2016 final rule failed to justify its restriction that only *one* path may be used as part of the required monitoring surveys when there are many possible routes that would achieve the same objectives, and EPA's response in the most recent proposal does not cure that failure.

EPA attempts to justify its overly prescriptive requirements in stating that the defined observation path is necessary because it cannot find another way to ensure owners/operators meet their compliance obligations to monitor all of their equipment.[7] But restricting monitoring surveys to a single path has no bearing on ensuring owners or operators meet their compliance obligations, and such a restriction does little to actually serve the valid objectives enunciated in the rule. For example, an owner/operator could physically view and monitor all of the equipment during a survey but still be in violation of the rule if a small departure from the observation path was taken while en route. If anything, EPA has created more inefficiency for OGI users by tying the requirements of OGI to the more antiquated Method 21 system rather than simply establishing the performance objective for OGI users to meet.

In addition, the costs of creating, maintaining, and updating sitemaps and observation paths are onerous and unnecessarily burdensome on owners/operators at affected facilities. EPA's statement in the Response to Comments regarding the observation path requirement is problematic because it assumes this

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[6] 79 Fed. Reg. 34960, 34,969 (Proposed Rule for *Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units*); *see also* 42 U.S.C. § 7411(b)(5) ("Except as otherwise authorized under subsection (h) of this section, nothing in this section shall be construed to require, or to authorize the Administrator to require, any new or modified source to install and operate any particular technological system of continuous emission reduction to comply with any new source standard of performance").

[7] *See* 81 Fed. Reg. at 35,860 ("B]ecause we are no longer requiring a traditional log of instrument readings…the rule must provide another way to ensure the compliance obligation to monitor all equipment is met. We believe that the observation path requirement effectively ensures that an operator looks at all the required components…").

is a "one time" obligation. That assumption is clearly not correct; components change over time, and this now creates a continual update requirement that itself could be violated (e.g., if a company adds a new component and the plan has not been updated, is it in violation of the requirement to have a "fugitive emissions monitoring plan" because a component that may be on a slightly different path is not included). Moreover, EPA's assumption fails to take into account that owners/operators may now be forced to create entirely new and separate management systems for the sole purpose of maintaining sitemaps and observation paths. While the notion of a "plan" and "observation path" may have intuitive appeal, a closer analysis shows that the layers of requirements to monitor compliance with the plan, the path development, the updates to them, and compliance with following them impose significant costs that the rulemaking has completely ignored to date.

API does not generally disagree with EPA's overall goals underlying the monitoring survey (namely, to ensure all regulated components are observed). But EPA's requirements go beyond that which is needed to assure compliance and actually limits the rule in a way that prevents other methods that accomplish the same result. The same result could be achieved with a *simple* requirement – one that ensures that all regulated components are observed without interferences. The 2016 rule entirely failed to address this fundamental issue, and the new proposed rule would perpetuate this fundamental problem with the 2016 requirements.

3.1.3 THE SITEMAP AND OBSERVATION PATH REQUIREMENTS ARE ARTIFICIALLY MANUFACTURING "DEVIATIONS" THAT MUST BE REPORTED AS VIOLATIONS FOR SOME FACILITIES.

EPA has indicated in some documents[8] that not following the path is "merely" a "deviation," but a review of the deviation definition strongly suggests that regulators will consider it a violation. Indeed, if EPA wanted to make a deviation clearly not a violation, it would not have defined deviation as a "failure to meet" an obligation and would have used another word, such as "excursion." EPA has taken such an approach before, e.g., in the Compliance Assurance Monitoring (CAM) rules, 40 C.F.R. part 64, in which the agency provided that excursions were instances in which a monitoring parameter was not met but made clear that this did not constitute a violation. As defined in Subpart OOOOa, however, deviation includes the failure to meet *any* requirement or obligation of the subpart. This logically leads to a conclusion that deviations from the observation path (and thus the monitoring plan) would likely be considered violations.

EPA states that these deviations are "not necessarily deviations from the requirements of the rule" and should even be expected by experienced OGI operators. But this reasoning does not assure owners and operators that they have not committed "deviations" because they are still vulnerable to deviation

[8] May 2016 RTC, at 4-706, EPA-HQ-OAR-2010-0505-6811; 83 Fed. Reg. at 52078.

reporting under other rules.[9] For example, some facilities subject to this rule are also subject to Title V permitting requirements. Pursuant to the Title V program, those operators must report all deviations. Those same facilities could also be subject to citations by states that elect to pursue them for their "deviations" from the rule, e.g., failing to follow the observation path as defined. EPA's assurances that are not reflected in the rule provisions or definitions do nothing to change the enforcement risk faced by these facilities or their obligation to report intermittent compliance status for those facilities subject to Title V permitting. It is possible that the proposal is merely stating that EPA would exercise its enforcement discretion not to pursue deviations (violations) of the observation path and sitemap provisions if they did not make a difference in the effectiveness of the observations, but a commitment to exercise discretion does not make an arbitrary provision rational.[10]

3.1.4 EPA Should Revise the Observation Path Requirement into a General Performance Objective.

API agrees with EPA that a monitoring plan is one rational way to implement the OGI requirements. It is the prescriptiveness in the elements of the plan with which API takes issue. Surveyors should ensure they have a clear view of all fugitive components during the surveys. The approach that should be taken to achieve this outcome, however, is one consistent with fundamental CAA Section 111 principles by setting the core requirements but not specifying how an owner/operator achieves those requirements. For example, EPA could specify that observations require the following elements: (1) clear views, (2) monitoring of all equipment, and (3) accurate imaging. Such a regulation would be in line with past CAA Section 111 rules and allow industry flexibility in achieving those metrics. Therefore, EPA should amend the rule to provide that each monitoring plan must include or state the following: *"Each monitoring survey shall be conducted in such a manner to ensure all fugitive components are surveyed."* No more is required.

A company may elect to create a pathway so that it can prove it observed all required components, but that should not be a requirement of the rule. Fundamentally, companies will need a basis for certifying that they met the requirements of the rule, but there is no reason that EPA should impose a one-way only methodology for doing that. This approach would ensure that all fugitive components are included in the monitoring survey while allowing industry to find the most suitable approach to achieving that objective. The sitemap and observation path currently prescribed by EPA would merely represent one of those approaches.[11] An example of the type of description that an operator may choose to include within their plan describing a general process is provided in Attachment D.

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[9] API acknowledges that the proposed rule eliminates some of the reporting requirements that would have required *all* deviations from the monitoring plan – including the observation path – to be reported in the facility's annual reports required under this subpart.

[10] EPA has also publicly stated that it does not intend to issue guidance on the monitoring plan – this shows EPA has no real intent to ensure that owners and operators are not subjected to unwarranted enforcement as a result of not following the defined observation path closely enough. It is in this sense that deviations will have been *manufactured* by EPA.

[11] In this scenario, EPA could also create a "safe harbor" provision that allows using the sitemap and observation path as one way for owners/operators to be deemed in compliance.

If EPA retains a "path" requirement, then departures from the observation path should be considered "excursions" and not deviations. EPA has stated that deviations from the monitoring plan are not necessarily deviations from rule requirements. Thus, "deviation" is not the appropriate label for a departure from the observation path. The definitions for Compliance Assurance Monitoring under 40 C.F.R. part 64 provide for an "excursion," and that approach should be adopted here (with modification); the). The Compliance Assurance Monitoring definition provides:

> *"Excursion shall mean a departure from an indicator range established for monitoring under this part, consistent with any averaging period specified for averaging the results of the monitoring."*

To the extent EPA includes any pathway provisions, deviations should not be considered a failure to meet the requirements of the rule. Instead, EPA could adopt an "excursion" definition along the following lines, based on 40 CFR §64.1:

> *"An "excursion" shall mean a departure from the observation path, as outlined in § 60.5397a(d), for an established monitoring plan under this part, that does not result in an omission by a monitoring surveyor to view or inspect any required emissions components, and/or does not interfere with the view or accuracy of the OGI equipment or operator in completing the survey of all required emissions components. An excursion is not a deviation from the requirements of this subpart."*

By using "excursion" to define the departure from the observation path, EPA could still identify when departures occurred, and owners and operators would be less vulnerable to "deviation" citations under other rules. A deviation would only occur if the surveys were made without clear views, failed to monitor all required components, and/or did not have accurate imaging. This characterization of a departure also comports with EPA's current understanding, since EPA states that it does not view all "departures" from the monitoring plan as deviations. An "excursion" would still allow a departure to be taken and noted but not result in a deviation/violation from the requirements of the rule.

4.0 EPA SHOULD DO MORE TO REDUCE AND SIMPLIFY ACTUAL BURDEN ASSOCIATED WITH RECORDKEEPING AND REPORTING

Subpart OOOOa continues to require onerous recordkeeping and reporting that exceed typical levels of compliance assurance and are a significant cost to operators to track and maintain. In this proposal, EPA increased the recordkeeping and reporting requirements under the guise of streamlining requirements without adequately justifying increased costs with respect to the administrative burden these proposed changes would require.

Furthermore, EPA requires a certifying official submit certification of all information submitted within the annual report in compliance to Subpart OOOOa. API believes that general recordkeeping of leak monitoring surveys provides compliance assurance and validates completion of surveys, including the identification of leaks and their repair.

4.1 REQUIREMENTS CREATE AN UNNECESSARY REGULATORY BURDEN AND ARE THEREFORE AT ODDS WITH EXECUTIVE ORDERS 13771, 13563, AND 12866.

The current proposed rule fails to meet the objectives of Executive Orders (EO) 13771, 13563, and 12866 as a result of the arbitrary restriction imposed on owners and operators to comply with a single defined observation path. Taken together, these Executive Orders direct and encourage federal agencies to reduce regulatory burdens and costs, implement regulations that are cost-effective, and consider the effect and need for the regulations on society, including private industry.

More specifically, EO 13771 directs executive agencies, including the EPA, to reduce regulation and control regulatory costs. [12] EO 13771 provides that "It is the policy of the executive branch to be prudent and financially responsible in the expenditure of funds, from both public and private sources." [13] EO 13771 further provides that "the cost of planned regulations be prudently managed and controlled." [14] In 1993, EO 12866 was issued to announce a regulatory policy that directs federal agencies to "promulgate only such regulations as are required by law, are necessary to interpret the law, or are made necessary by compelling public need," and in making such a determination, "to assess all costs and benefits including the alternative of not regulating."[15] EO 12866 also directs agencies to "design its regulations in the most *cost-effective* manner to achieve the regulatory objective." [16]

In 2011, EO 13563 was issued to be "supplemental to and reaffirms the principles, structures, and definitions governing contemporary regulatory review that were established in Executive Order 12866 of September 30, 1993." [17] EO 13563 expressly reiterates and affirms that each agency must (among other things) "propose or adopt a regulation only upon a reasoned determination that its benefits justify its costs…" "tailor its regulations to impose the least burden on society … taking into account…the costs of cumulative regulations," and "to the extent feasible, specify performance objectives, rather than specifying the behavior or manner of compliance that regulated entities must adopt." [18]

As discussed above, EPA has yet to provide a reasoned explanation or guidance as to why its restrictive approach is reasonable. The current proposed rule creates a significant monetary, resource, and management intensive regulatory burden on owners and operators subject to subpart OOOOa that provides little, if any, benefit, and could be achieved by much simpler and more flexible means (e.g. performance objectives for each monitoring survey). Neither the final rule or current proposed rule align with the objectives of these EOs.

Recommendation:

API respectfully requests that EPA carefully consider the objectives in EO 13771, 13563, and 12866 and as a result of that review, delete or substantially modify the requirements as discussed in these comments.

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[12] E.O. 13771 of Jan 30, 2017.
[13] *Id.*
[14] *Id.*
[15] E.O. 12866 of Sept. 30, 1993.
[16] *Id.* (emphasis added).
[17] E.O. 13563 of Jan. 21, 2011.
[18] *Id.* (emphasis added).

4.2 FUGITIVE EMISSIONS AT WELL SITES AND COMPRESSOR STATIONS

EPA continues to ignore the scale of sites that are subject and will become subject to these provisions over time. We continue to request the Agency seek to reduce the administrative burden to operators by reducing the amount of records required to be maintained and reported for each leak survey. API recognizes that it is appropriate to maintain sufficient records to demonstrate that fugitive emissions are adequately identified and subsequently repaired. However, it is API's view that it is excessive to require such a significant level of detail to be both documented and submitted.

4.2.1 RECORDKEEPING FOR FUGITIVES

API appreciates EPA's proposed changes to allow for a unique identifier for survey personnel, protecting the privacy of company employees and contractors.

The general recordkeeping of leak monitoring surveys provides compliance assurance and validates completion of surveys, including the identification of leaks and their repair. The additional photographs required to be maintained do not provide additional assurance beyond the survey records maintained, submitted and certified in the annual report. Maintaining thousands of photographs in addition to the details required to be recorded is additional cost and administrative burden to track and organize. The level of data required for recordkeeping and reporting within Subpart OOOOa already includes significantly more data points than other traditional LDAR programs. As stated in our petition for reconsideration, EPA should reduce the recordkeeping burden for conducting the leak monitoring by removing the digital photo requirement for each OGI survey. At a minimum, EPA should modify the rule to make the photo requirement optional similar to that for reduced emission completion recordkeeping, where the use of photographs is an alternative in place of other recordkeeping requirements.

Within this proposal EPA has also added additional data points that should be eliminated or simplified as we discussed throughout Comment 1.0.

EPA should remove the following recordkeeping requirements:

- Digital photographs.
- When using OGI, ambient temperature, sky conditions, and reference to max wind speed (i.e. document wind speed only).
- Instrumentation used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding
- Number and type of components that were tagged as a result of not being repaired during the monitoring survey.
- Repair methods applied in each attempt to repair beyond identification that the leak was fixed.

This would still retain a substantial amount of the recordkeeping information per survey including:

- Location of each fugitive emission.
- Number and type of components for which fugitive emissions were detected.
- Number and type of difficult-to-monitor and unsafe-to-monitor fugitive emission components monitored.

- Instrument reading of each fugitive emissions component that requires repair when Method 21 is used for monitoring.
- Number and type of fugitive emissions components that were not repaired as required.
- Number and type of components that were tagged as a result of not being repaired during the monitoring survey.
- Repair methods applied in each attempt to repair.
- Number and type of fugitive emission components placed on delay of repair and explanation for each.
- Date of the survey.
- Beginning and end time of the survey.
- Monitoring instrument used.
- Fugitive emissions component identification when Method 21 is used to perform the monitoring survey.
- Wind speed at the time of the survey.
- Narrative of how survey process was performed or statement no excursions from the narrative in the monitoring plan occurred.

Recommendation:

EPA should simplify the recordkeeping and reporting requirements to those that ensure compliance without additional administrative burden. Some examples include removal of the digital photographs and elimination of tracking environmental conditions beyond wind speed. Only elements needed for compliance assurance should be requested within the annual report. Supporting records retained by companies can be made available upon request from the Agency.

4.2.2 Reporting for Fugitives

All of the existing reporting requirements are not necessary for the agency to assess whether ongoing compliance is being attained. It is incumbent on all reporting entities to self-report any non-compliance with the regulation. As part of the existing reporting, entities are required to inform the agency of any deviations from requirements. It would substantially reduce the reporting burden if entities were only required to submit limited information that would make known any compliance issues that occurred during the reporting period. In the absence of such issues, it is excessive to require the provision of every detail for every survey of every affected facility.

Recommendation:

API requests that EPA limit the reporting requirements to the most relevant information to assure compliance focused on the identification and subsequent repair of leaking components. We believe this can be achieved by the following data points, which is consistent with the level and format of data state programs require. As we have stated before, supporting records can be made available to the Administrator upon request:

- Site ID

- Date of the survey;
- Number and type of components for which fugitive emissions were detected;
- Number and type of fugitive emissions components that were not repaired as required;
- Number and type of fugitive emission components placed on delay of repair and explanation for each delay of repair;;
- Deviations from requirements associated with survey frequency and repair time; and
- Identification a well site meets the criteria for wellhead only and will cease monitoring.

4.2.3 NEWLY PROPOSED RECORDKEEPING AND REPORTING ELEMENTS SHOULD BE REMOVED

Additionally, EPA has proposed additional reporting specific to leak monitoring. These data points should not be finalized for reporting as proposed. Examples of these reporting elements include:

- *Low production determination by well site*: The determination should be documented and records retained. The production rate itself should not be reported. If biennial monitoring frequency is retained, companies can provide documentation that the well meets the criteria for being a low production well site. See Comment 1.2.1
- *For wellhead only sites:* API requests EPA simplify the reporting associated with the removal of equipment at a well site resulting in it becoming a wellhead only facility. EPA should simplify the reporting requirements to a one-time notification within the annual report for that well site. If equipment is added back to the site, leak detection would resume, and the well site would have full reporting information associated with it. Therefore, the following information is unnecessary to be recorded or reported:
    - Date of removal of the last piece of major production and processing equipment
    - Well ID or separate tank battery ID receiving the production.
    - Date first piece of major production and processing equipment added back.

4.2.4 REPORTING FOR EQUIVALENT STATE PROGRAMS

State Agencies have recordkeeping and reporting requirements to ensure compliance with their leak detection programs, and. EPA should give proper deference to states for compliance assurance for their state programs. Complying with multiple recordkeeping and reporting schemes for the same site(s) is an enormous administrative burden for operators to maintain with no added environmental benefit. Requiring federal reporting, as EPA has proposed, would require Subpart OOOOa recordkeeping requirements to be met in order to comply with the reporting elements required in § 60.5420a(b)(7). Since EPA has proposed equivalence to the state recordkeeping programs, we also request EPA defer equivalency of reporting. Without doing so will defeat the purpose, and any benefit from EPA approving these state programs in the first place.

Additionally, EPA requires an advance notice within 90 days that a site is complying with the state LDAR program. API recommends that a one-time notification be submitted prior to the first LDAR survey (similar to written / electronic notification process associated with hydraulic fracturing of a well).

Additional comments on this topic are provided in Comment 6.0

4.3 OTHER RECORDKEEPING AND REPORTING SIMPLIFICATION REQUESTS

API has provided comments on recordkeeping and reporting aspects of Subpart OOOOa throughout this comment letter. Below is a list of each topic and the section that can be cross referenced:

- Technical Infeasibility assessments for pneumatic pumps - Comment 8.2
- CVS Inspections – Comment 10.2
- Well Completion Operations that Immediately Start Production – Comment 11.3
- Performance Testing - The previous rule required operators to conduct a visible emissions test only and the change in administrative burden with respect to reporting has not been adequately explained or justified.
    - Was the combustion unit returned to operation from a maintenance or repair activity?
    - Date of visible emissions test
    - Length of the test
    - Amount of time visible emissions present

4.4 TESTING AND REVIEW OF THE CEDRI REPORTING FORM

There are significant changes to the CEDRI forms and API and industry should be afforded more time to review. Some initial feedback includes the following:

- The form includes numerous data elements not required for reporting. EPA should remove any reporting requirement that is listed as optional. These fields are not required and add unnecessary information to an already long list of reporting requirements.
- API believes the form should be tested and reviewed with industry prior to the Final Template's release. The current version has various issues such as cells being locked and drop-downs not working consistently as well as missing relevant options.
- Through the guise of streamlining reporting, EPA has added significantly to data required to be included within the annual report. Many of these data points previously only were required to be maintained through recordkeeping. The administrative burden with respect to reporting has not been adequately explained or justified within the proposed rule.

5.0 PROVISIONS FOR NEW AND EMERGING TECHNOLOGY ALTERNATIVE MEANS OF EMISSION LIMITATION

Less expensive and more effective monitoring technologies will accelerate the production of clean domestic energy, helping to deliver a healthy environment and economy. EPA must revise the AMEL provisions of Subpart OOOOa to unlock the benefits of these emerging technologies.

5.1 API SUPPORTS THE OPTIONS IN THE PROPOSED RULE TO USE MODELING, TO TEST TECHNOLOGIES IN A CONTROLLED TEST ENVIRONMENT, AND TO ALLOW MANUFACTURERS/VENDORS TO APPLY FOR APPROVALS.

5.1.1 MODELING

API strongly supports the inclusion of modeling, in addition to limited field data, to demonstrate the performance of a specific technology. This is a preferred and recommended option to the onerous requirement to gather 12 months of field data. The 2018 Interstate Technology and Regulatory Council ("ITRC") paper states, "Computer modeling is highly valuable for evaluating emission reduction objectives due to the probabilistic nature of emission rates."[19] The paper also states that "computer-based modeling, coupled with empirical validation of model accuracy, is a potential solution to rigorously evaluate application efficacy under the most likely encountered meteorological and site conditions. The Fugitive Emissions Abatement Simulation Toolkit (FEAST) model is a virtual gas field simulator that predicts emission reductions of various leak detection and repair programs. An effective demonstration of equivalency could include an empirical evaluation of an application at a structurally complex site such as a gathering compressor station over a time period, such as twelve months, that assesses performance under a wide range of meteorological conditions. If a computer model can accurately predict the detection limit and response time for different sources as a function of environmental parameters, then a probabilistic model can be used to simulate performance at other sites. This approach could allow a scientifically rigorous determination of equivalency while minimizing the number of sites required for field testing." [20] Additionally, modeling is a highly valuable tool in that it allows for comparison of the "end game" of equivalent emissions reductions (i.e., allows for comparison of two approaches/work practices rather than specific technology detection thresholds).

Further, EPA used modeled simulations when it simulated the frequency and distribution of leaks in order to compare OGI to Method 21 and approve OGI as an "alternative work practice to detect leaks from equipment" ("OGI AWP").[21] EPA used a Monte Carlo model to evaluate and approve the use of OGI as an alternative work practice (AWP) for fugitive emissions monitoring. "In developing the AWP, EPA sought to design a program for using the optical gas imaging instrument that would provide for emissions reductions of leaking equipment at least as equivalent as the current work practice. To do so, we used the Monte Carlo model for determining what leak rate definition and what monitoring frequency were necessary for the AWP." At no point in its approval of OGI did EPA require site-specific modeling.

We strongly urge EPA to apply the same logic to AMEL equivalence demonstrations. There is no reason why rigorous statistical modeling, combined with real-world field data and thorough documentation and recordkeeping, should not be sufficient for EPA to make a reasoned decision on broadly approving a new technology.

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[19] Interstate Technology and Regulatory Council (ITRC). 2018. Evaluation of Innovative Methane Detection Technologies. Section 5.2 Design Elements. Methane-1. Washington D.C.: Interstate Technology and Regulatory Council, Methane team. https://methane-1.itrcweb.org

[20] *Id.*

[21] Alternative Work Practice to Detect Leaks from Equipment Final Rule, 73 Fed. Reg. 78201 (add date)

5.1.2 CONTROLLED TEST ENVIRONMENT

Use of a controlled test environment, such as Colorado State University's Methane Emissions Technology Evaluation Centre (METEC) to gather field data on the performance of various leak detection technologies and compare their capabilities to current approved methods, such as OGI, would greatly streamline the process of determining equivalence, as well as the lengthy CAA Section 111(h) application and approval process. API appreciates EPA including this option in the proposal and further recommends that a facility such as METEC be recognized by EPA as a facility where all suitable technologies could be tested for equivalency. The team at METEC is currently working to establish a baseline for OGI for this very purpose. In fact, EPA has funded work at METEC toward developing the baseline for OGI. Testing a new technology against a clearly established baseline and following a pre-set methodology for testing would provide consistency and confidence in the process. If manufacturers are aware of baseline emissions reduction for OGI, they would clearly know what standard their technology must meet to be deemed equivalent. As a result, this would streamline the process and allow new technologies to successfully navigate this application and approval process and be deployed faster. This would result in faster, cost-effective emissions reductions.

The ITRC paper referenced above supports this concept and states, "Controlled releases under field conditions are ideal for systems with emission source objectives because they can assess the accuracy of source quantification and/or localization under realistic meteorological conditions. Long-term testing at field sites allows controlled releases to be tested under a diversity of meteorological conditions. Performing multiple controlled releases under each set of conditions can be used to calculate the probability of detection as a function of emission rates and other relevant conditions such as wind speed."[22] Therefore, gathering field data at a facility such as METEC would prove extremely useful and could effectively take the place of gathering field data at an active oil and gas well site. API recommends that testing technologies in a controlled test environment, in addition to modeling, to minimize the field data necessary to demonstrate the performance of various technologies and achieve approvals.

5.1.3 VENDORS/MANUFACTURERS SHOULD BE ALLOWED TO APPLY FOR APPROVAL OF EMERGING TECHNOLOGY

Vendors/manufacturers of new leak detection technologies are the experts in this advanced, high-tech area and are the appropriate person(s) to apply for approval of a technology to be used in compliance with Subpart OOOOa for methane and/or VOC leak detection. API appreciates the inclusion of this language in the proposal. However, API recommends that the operator not be required to be a party to the application and approval process as well since the technologies are being developed for broad applicability.

[22] *Id.*

5.2 EPA SHOULD ALLOW FOR BASIN-WIDE APPROVALS OF EMERGING TECHNOLOGY FOR USE IN COMPLYING WITH THE LEAK DETECTION REQUIREMENTS IN THE RULE.

One of API's priority concerns in the proposed Subpart OOOOa technical revisions is the requirement to apply for the use of emerging technologies on a site-specific level. Outlined below are the technical and legal reasons why this would be an enormous and unnecessary burden, not feasible to undertake from an administrative and timing perspective, not necessary for showing equivalence to the current method, and will greatly stifle innovation in this very dynamic area of technological advancement.

Numerous technologies are currently being developed and piloted at oil and gas field sites throughout the country. Many of these state-of-the-art technologies in development have the potential to detect leaks faster and more efficiently, which could enable the operators to make timely repairs resulting in less fugitive emissions, resulting in a win-win for both the operator and the environment.

5.2.1 SITE-SPECIFIC VARIABLES CAN BE ADDRESSED IN CONDITIONS REQUIRED FOR THE USE OF THE TECHNOLOGY

In the proposal, EPA states that "we are not changing the requirement that AMEL's be site-specific because we are aware of the variability of this sector and are concerned that the procedures may need to be adjusted based on site-specific conditions (e.g., gas compositions, allowable emission or landscape)."[23] There is no logic behind this statement, and this reasoning does not withstand scrutiny. If a technology is designed to measure methane molecules in the atmosphere, it will measure methane molecules in the atmosphere, regardless of what the site looks like or the gas composition. If there is methane above a certain concentration, the technology should find it. Further, EPA can establish clear and consistent parameters under which a technology will be able to detect methane emissions. The approval of the technology could have certain conditions assigned to it that are required to be met in order for the technology to be used at a site, similar to EPA's technology-based approval for OGI that had minimum/maximum temperatures and minimum/maximum distance parameters required to be present, for example.

In response to EPA's mention of landscaping being a site-specific variable, if the landscaping at a particular site impedes the path of the technology to effectively operate, for example, then the technology may not be used at that site until the landscaping is in compliance with the parameters required to be met for the proper operation of the specific technology. Again, this could be a condition for the use of a specific technology at a specific site. Continuous sensors, for example, allow for continuously monitoring a site for leaks and are particularly suited for intermittent leaks at very low thresholds. Day or night time is immaterial for detection by continuous sensors. On the other hand, aerial-based surveys might have limitations flying at night and may use sunlight as reference. As such, these surveys would need to be deployed only during the daytime.

EPA stating that a technology should be able to distinguish allowable emissions as a site-specific variable is irrelevant to the case for a site-specific approval. Every site has allowable emissions that could result in some venting that is allowed if under threshold levels. Differentiating allowable venting, for example, from fugitive emissions leaks could arguably be an issue against the approval of any technology but that

[23] Subpart OOOOa Proposed Technical Revisions, 83 Fed. Reg. 52080 (October 15, 2018)

should not be a reason to disallow approval on a basin-wide level and stifle all development in this important area. An approach where detection may be impacted by allowable emissions may be an approach that is used to direct inspection efforts. Some technologies could be used as a frequent screening tool and may require the operator to visit the site with OGI, for example, to detect the source of the leak(s). But it would flag the large emitter sites and again, enable the operator to find and fix the largest leaks faster.

In the OGI AWP final rule, EPA stated, "the standard is an alternative to the existing work practice and maybe used in place of the existing work practice where feasible and whenever the owner or operator chooses to do so." [24] As this language clearly states, OGI received approval from the EPA, but if a site did not meet the conditions then the technology was deemed not feasible at that site at that time. Similarly, EPA should provide approvals for alternative technologies and include qualifications for their use "where feasible

5.2.2 SITE SPECIFIC DATA IS NOT NECESSARY TO DETERMINE EQUIVALENCY AND RECEIVE APPROVAL PER CLEAN AIR ACT 111(H)

There is no legal impediment to demonstrating that an AMEL is equivalent to a Section 111(h)(1) of CAA standard based on differences between the AMEL and the standard against which it is being evaluated – such as differences in the frequency (e.g., annual, semi-annual, quarterly) over which the monitoring or other requirements must occur. The current regulations for implementing Subpart OOOOa state that EPA "may condition permission [to use an AMEL] on requirements related to the operation and maintenance of the alternative means." 40 C.F.R. § 60.5398a(a). Such requirements could easily include frequency of the deployment or operation of the AMEL.

The technologies being developed have different methane sensitivity thresholds and can operate at different frequencies. For example, a spectrometer (i.e., laser-based technology) mounted on an airplane can scan over an entire basin in a day. It could do these fly-overs more quickly and efficiently than a person using a hand held OGI camera on foot at a site and therefore, could have a higher frequency assigned to it and this would be a feasible alternative. Based on cost-benefit analysis, some of these emerging technologies have been shown to be favorable and a preferred option for some member operators.

In the OGI AWP, EPA states, "The emission control effectiveness of any work practice is a function of both 1) its ability to detect leakage and 2) the frequency of monitoring. An equivalent work practice may require more frequent monitoring, depending on its mass rate threshold for detecting leaks."[25] If the fly-over technology has a lower sensitivity threshold, it may only find larger leaks, but it could find these larger leaks faster with a more frequent monitoring schedule.

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[24] Alternative Work Practice to Detect Leaks From Equipment Final Rule (73 Fed. Reg. 78204)
[25] Alternative Work Practice to Detect Leaks From Equipment Proposed Rule (71 Fed. Reg. 17404)

EPA further states, "A more frequent monitoring requirement becomes necessary because higher mass emission reductions from large leaks, found earlier, are offset by some degree by smaller leaks which go undetected."[26] Of Equivalency in Section 111(h)(3) is discussed simply as "a reduction in emissions of any air pollutant at least equivalent to the reduction in emissions of such air pollutant [under the current work practice]." Based on this standard in the statute, larger leaks found earlier and more frequently should reasonably be able to offset smaller leaks that may not be found as timely.

Further, in referring to OGI in the AWP final rule, EPA stated, "The results show that the AWP will achieve EPA's goal of detecting leaking equipment from which the majority of emissions arise**."**[27]

Therefore, similar to EPA's approach in the AWP OGI rulemaking, EPA should focus on basin-wide (or category-wide) mitigation equivalence, not detection equivalence. For example, a one-time aerial-based survey with a more cost effective, less sensitive technology may not be able to detect emissions with the same sensitivity as ground-based technologies, or detection equivalence, but conducting multiple surveys instead of one would mean that any potential fat-tail emission sources are identified ten times faster than a ground-based method. Mitigation equivalence can only be achieved across many sites, because of the relatively few sites that produce the bulk of emissions. Further, basin-wide approaches are likely to be more accurate in terms of estimating total emission reductions than individual site estimates given the high variability in individual site emissions.

EPA can use statistical models such as FEAST to make data-driven decisions about equivalence. EPA can then incorporate basin-specific emissions data into modeling to ensure that its emission reduction objectives are being met. Making decisions based on aggregated data reduces the uncertainty that comes with site-specific estimates. API recommends that site attributes could be obtained from a small number of representative sites in the basin; then that data, coupled with modeling and testing in a controlled test environment would be adequate to determine if equivalency is achieved. Further, once a technology is approved to be used in a specific basin, all new well sites drilled and constructed in that basin going forward will have the opportunity to use that technology without going through the onerous 111(h) application and approval process for each new site or groups of new sites all over again. Again, the proposed approval process is not feasible and would stifle development of leak detection technologies.

Therefore, based on this information and EPA's logic in this previous OGI AWP rulemaking, once this technology has been deemed equivalent based on emissions reductions achieved in a specific basin, use of the technology in that basin should be the subject of the application for approval. As explained above, the approval could be granted with conditions that would need to be met at each site prior to the technology being used.

[26] *Id.*
[27] Alternative Work Practice to Detect Leaks from Equipment Final Rule, 73 Fed. Reg. 78203, (add date)

5.2.3 COMMON SENSE DICTATES BASIN-LEVEL APPROVAL

Clean Air Act section 111(h) requires that an alternative work practice must first be shown to be equivalent and then be subject to a notice and comment period and possible public hearing. Gathering the field data, performing modeling, and showing equivalence will be a lengthy process of at least a year or more. Then the notice and comment period will take months. EPA stated in the Subpart OOOOa final rule that they would make a decision within 6 months of close of the comment period.[28] Therefore, realistically, this process would take approximately two years. To do this for every single well site, such as a well or wells on a pad or a centralized tank battery would be unmanageable. It would be lengthy and it is unlikely that a vendor/manufacturer or operator would undertake the effort.

One API member who operates solely in the Permian Basin in Texas reported hundreds well sites subject to the Subpart OOOOa LDAR monitoring for 2018. Going through this 111(h) process for each of these sites in order to use a new, more effective and efficient technology to detect methane emissions for compliance could take at least two years per site. This does not account for the new wells this operator is drilling in the Permian Basin every month (with about 3 wells/pad or well site) and building around 4-6 large centralized tank batteries per year that would also require site-specific approval per the current language in the rule.

API requests that EPA reconsider this site-specific approach and approve a basin-wide (or category-wide) approach. Not doing so would stifle innovation in this technologically advanced, dynamic area. The environmental benefit of the rule could continue to increase if EPA would allow more than handheld OGI cameras or Method 21 to detect leaks in compliance with Subpart OOOOa.

5.2.4 CLEAN AIR ACT SEC. 111(H)(3) DOES NOT CONSTRAIN BASIN-WIDE APPROVALS

EPA should provide a procedure for approving an Alternative Means of Emission Limitation ("AMEL") under Subpart OOOOa for categories of sources rather than limit an AMEL to an inefficient and unworkable source-by-source application. The structure and language of section 111 and EPA's decision to allow for similar flexibilities under other CAA provisions confirm that applying an AMEL to source categories is appropriate and lawful.

CAA Section 111 calls on the Administrator to list "categories of stationary sources" that "cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." 42 U.S.C. § 7411(b)(1)(A). The Act then calls on the Administrator to promulgate and subsequently revise every eight years, if appropriate, "standards of performance for new sources within such source category." *Id.* § 7411(b)(1)(B). The Act defines a standard of performance for purposes of section 111 as:

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

[28] Subpart OOOOa Final Rule, 81 Fed. Reg. 35861 (June 3, 2016)

Id. § 7411(a)(1). In the event it is not feasible to establish such a standard, section 111(h)(1) authorizes the Administrator instead to "promulgate a design, equipment, work practice, or operational standard, or combination thereof." *Id*. § 7411(h)(1). Section 111(h)(1) does not refer to categories of sources or individual sources, but because a section 111(h) standard is intended to replace a standard of performance applicable to an entire source category, the logical inference is that section 111(h) standards also apply to source categories. Section 111(h)(3) provides for an AMEL when:

> *"after notice and opportunity for public hearing, any person establishes to the satisfaction of the Administrator that an [AMEL] will achieve a reduction in emissions of any air pollutant at least equivalent to the reduction in emissions of such air pollutant achieved under the requirements of [section 111(h)(1)]."*

Id. § 111(h)(3). On the face of this language, because any AMEL will serve as a replacement for a category-wide 111(h)(1) standard, any demonstration that an AMEL will achieve an emission reduction at least equivalent to a 111(h)(1) standard could reasonably be made on a category-wide basis and be applied to an entire source category.

Section 111(h)(3) also states, however, that once a successful equivalency demonstration has been made, "the Administrator shall permit the use of such alternative by the source for purposes of compliance with this section with respect to such pollutant." Id. The fact that this provision has been used for the authorization of source-specific AMEL applications should not be interpreted to preclude EPA's authorization of an AMEL on a source category-wide basis. Indeed, provided an adequate demonstration for a single source within a source category can be made and it can be established that there are no material differences between that source and the other sources in the category that would render the AMEL less than equivalent to a section 11(h)(1) standard, there is no reason, based on the statute, to prohibit category-wide application of AMEL. Indeed, any other number of approaches, including a more generalized approach that does not focus on individual sources for making an adequate category-wide demonstration under Section 111(h)(3) may be available, and EPA should evaluate them on a case-by-case basis.

Allowing for source category-wide AMEL determinations would be consistent not only with the overall structure of section 111 and its focus on category-wide standards under sections 111(b) and 111(h)(1); it is also consistent with the limitation prohibiting EPA from imposing specific technological emission reduction requirements pursuant to Section 111. Section 111(b)(5) states:

> *"Except as otherwise authorized under subsection (h) …, nothing in this section shall be construed to require, or to authorize the Administrator to require, any new or modified source to install and operate any particular technological system of continuous emission reduction to comply with any new source standard of performance."*

Id. § 7411(b)(5). Section 111(h)(1) allows EPA, under limited circumstances, to impose a standard "which reflects the best technological system of continuous emission reduction." Section 111(h)(3) serves as a safety valve on that authority and thereby functions to further the policy set out in Section 111(b)(5). To give full effect to that policy, EPA should allow for category-wide AMEL demonstrations.

Adopting such an interpretation for Section 111(h)(3) would also be consistent with the policy EPA has adopted for the nearly identical provision in Section 112(h)(3), which authorizes an AMEL under the provisions of the CAA governing national emission standards for hazardous air pollutants. EPA's regulation implementing section 112(h)(3) recognizes that EPA is authorized to approve an AMEL for "source(s) *or category(ies) of sources* on which the alternative means will achieve equivalent emission reductions." 40 C.F.R. § 61.12 (emphasis added). Given the similarities between the programs authorized under Section 111 and section 112 and, in particular, the similarity of Section 111(h)(3) and 112(h)(3), EPA should adopt its policy of applying an AMEL to source categories for Section 111(h)(3) in the same manner as it has done with respect to section 112(h)(3).

Moreover, EPA has adopted similarly flexible approaches under other provisions of the CAA. For example, under the Act's visibility provisions, EPA must require states to include in their state implementation plans measures reflecting "best available retrofit technology" ("BART") for certain "major stationary sources." 42 U.S.C. § 7491(b)(2)(A). The Act further states that BART must control emissions "from such source," and defines BART as taking into account, among other things, "any existing pollution control technology in use at the source" and "the remaining useful life of the source." *Id*. § 7491(b)(2)(A), (g)(2). Despite the focus of the statutory language on determinations for individual sources, EPA's rules allow EPA and the states to authorize BART alternatives that can apply to groups of sources and that allow emission averaging across sources, even over wide regions, in lieu of imposing source-specific emission limits or source-specific alternatives to such limits. 40 C.F.R. § 51.208(e)(2). The courts have consistently affirmed the authority of EPA and the states in this regard. *See, e.g.*, *Util. Air Regulatory Grp. v. EPA*, 471 F.3d 1333 (D.C. Cir. 2006); *Central Ariz. Water Conserv. Distr. v. EPA*, 990 F.2d 1531 (9th Cir. 1993). If alternatives to emission limits (or work practice standards) for groups of sources under these provisions are permissible despite the continued references to the term "source," then surely a source category-wide AMEL is permissible under section 111(h)(3).

6.0 ALTERNATIVE MEANS OF EMISSION LIMITATIONS FOR STATE EQUIVALENCY

6.1 EPA SHOULD RECOGNIZE THE APPROVED STATE PROGRAMS AS WHOLLY EQUIVALENT LDAR PROGRAMS AND FULLY DELEGATE THE IMPLEMENTATION OF THE LDAR MONITORING PROVISIONS TO THESE RESPECTIVE STATES

In the state LDAR program equivalency guidance document EPA provided with this rulemaking, EPA explained that they analyzed the sensitivity thresholds and monitoring frequencies of approved technologies in a number of state programs, as well as other program requirements and, based on all of these variables combined, deemed these various state programs equivalent to Subpart OOOOa's LDAR program.[29] However, EPA is requiring operators to use the fugitive emission component definition from Subpart OOOOa, in addition to the reporting and monitoring plan.

Under the well-established premise of cooperative federalism, EPA should recognize these programs in full, including the states' recordkeeping and reporting requirements. Cooperative federalism is a central tenet of the Clean Air Act. Over the course of its fifty-year history, the Act has evolved first from a set of general principles intended to guide States as they undertook regulation of air pollution sources to an extensive number of more targeted standards often prescribed by the federal government in the first

[29] https://www.regulations.gov/document?D=EPA-HQ-OAR-2017-0483-0041 – Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Proposed Standards at 40 CFR Part 60, Subpart OOOOa dated April 12, 2018. .

instance and then implemented by the states. The principle that the States and the federal government will work in tandem to protect the nation's air resources is embodied throughout the Act. Congress, in section 101(a)(3) of the Act, declared air pollution control to be "the primary responsibility of States and local governments," 42 U.S.C. § 7401(a)(3), with the federal government providing "financial assistance and leadership," *id.* § 7401(a)(4).

For example, pursuant to section 110 of the CAA, while EPA develops the national ambient air quality standards, *see* 42 U.S.C. §§ 7408, 7409, states develop plans, called state implementation plans, to meet those standards. In that context, the U.S. Supreme Court has made clear that "[t]he Act gives the Agency no authority to question the wisdom of a State's choices of emission limitations if they are part of a plan which satisfies the standards." *Train v. Natural Res. Def. Council, Inc.*, 421 U.S. 60, 79 (1975). Similarly, under the CAA's visibility provisions, states have broad leeway to develop plans to combat regional haze that EPA cannot second-guess if the states have considered the statutory factors. *Am. Corn Growers Ass'n v. EPA*, 291 F.3d 1, 8 (D.C. Cir. 2002).

Section 111 of the CAA, the provision at issue here, fits squarely within the cooperative federalism tradition, with section 111(c) expressly calling on states to develop "a procedure for implementing and enforcing standards of performance for new sources" and calling on the Administrator to delegate "any authority he has … to implement and enforce such standards." 42 U.S.C. § 7411(c)(1). The Supreme Court has affirmed that these cooperative principles are the heart of the CAA again and again. *See, e.g.*, *Whitman v. Am. Trucking Ass'ns*, 531 U.S. 457, 470 (2001) ("It is to the States that the CAA assigns initial and primary responsibility for deciding what emissions reductions will be required from which sources."); *Union Elec. Co. v. EPA*, 427 U.S. 246, 269 (1976) ("Congress plainly left with the States, so long as the [NAAQS] were met, the power to determine which sources would be burdened by regulation and to what extent.").

We provide additional comments on specific reporting elements in Comment 4.2.4.

6.2 ALTERNATIVELY, EPA COULD REQUIRE THE FUGITIVE EMISSIONS COMPONENT DEFINITION FROM SUBPART OOOOA TO BE USED WHEN FOLLOWING AN ALTERNATIVE APPROVED STATE PROGRAM, BUT EPA SHOULD NOT REQUIRE A DUPLICATIVE ADMINISTRATIVE BURDEN.

EPA could finalize a hybrid approach and require that, if an operator complies with an "approved" state LDAR program then the operator must follow the fugitive emission comment definition in Subpart OOOOa and assure that all components are included in the surveys (even if the fugitive emissions component definition in the state program is less expansive). However, there should be no reporting, recordkeeping or monitoring plan requirements as that is an administrative burden with no added environmental benefit and further defeats any benefit from EPA approving these state programs in the first place.

6.3 TYPOGRAPHICAL ERRORS WITHIN § 60.5399A

There are appear to be typographical errors in the proposal rule regarding state program equivalency. Specifically, EPA appears to only approve Method 21 under Ohio's program; however, EPA's review memo included use of OGI as well. For Pennsylvania, EPA has listed GP-5 twice in the regulatory text. Well sites should be associated with GP-5a and compressor stations with GP-5.

Additionally, EPA only included the Texas Standard Permit but missed the Texas Non-rule Standard Permit[30]. The Non-rule Standard Permit's LDAR provisions are similar to the Standard Permit. API requests that EPA add the Texas Non-rule Standard Permit to the approved State AMELs.

7.0 STORAGE VESSEL APPLICABILITY

API opposes the proposed changes to regulatory language regarding the determination of Subpart OOOOa applicability for storage vessels. EPA's proposed revisions to the storage vessel applicability language in § 60.5365a(e) and its proposed revisions for the definition of "*maximum average daily throughput"* results in a very impractical and inappropriate method for calculating and using the 30-day production applicability period. EPA's proposed revisions involve EPA in states agencies' authority to issue air permits containing legally and practically enforceable limits on VOC emissions from individual storage tanks and compromises Cooperative Federalism between EPA and state agencies. See: https://www.epa.gov/home/cooperative-federalism-epa: "*EPA is embracing cooperative federalism and working collaboratively with states, local government, and tribes to implement laws that protect human health and the environment, rather than dictating one-size-fits-all mandates from Washington.*" *(Emphasis added).*

7.1 TECHNICAL AND PRACTICAL ISSUES WITH THE PROPOSED REVISIONS TO DEFINITION OF "*MAXIMUM AVERAGE DAILY THROUGHPUT*"

EPA's proposed revised definition of "maximum daily average throughput" is not practical or appropriate. The proposed approach would frequently result in situations where the total emissions resulting from calculations to determine applicability can be multiple times what the actual emissions are for situations when more than one tank is present (which occurs in the vast majority of situations with new storage vessels). Specifically, for a situation where a site has produced fluids flowing to a group of "x number" storage vessels, it would be quite common to end up with emission estimates for individual storage vessels as well as the group as a whole that are "x number" times the actual emissions.

There are a number of different ways in which companies configure groups of tanks, but for the purposes of this discussion, let's focus on an example site with four (4) 400-barrel storage vessels where flow is being routed to one vessel at a time, until that vessel is full, and then to other vessels. If we assume that each vessel takes 7.5 days to fill, at the end of 30 days, we would have 4 full storage vessels containing a total of 1600 barrels of fluids. Applying EPA's proposed approach to this situation would mean that each storage vessel would need to estimate emissions assuming a flow rate of 400 barrels per 7.5 days or 53.3 bbl/day. With four storage vessels present and each calculating this way, EPA's proposed method would result in total emissions based on 53.3 x 4, or 213.2 barrels per day of production, when the actual production rate is only 53.3 barrels per day. Of course, to obtain a correct "average production or throughput" the correct answer would be to divide the total 30-day production through each tank by 30 days (400 barrels x 7.5 days / 30 days = 100 barrels).

[30] https://www.tceq.texas.gov/permitting/air/newsourcereview/chemical/oil_and_gas_sp.html

Additionally, most wells decline significantly over the first year at a rate of up to approximately 50 to 80 percent. Thus, the actual average emissions for the first year may only be an average of approximately 32 barrels per day when one considers production decline. With EPA's assumption in this case, production could be estimated as much as 6.6 times the actual production rate in the first year. Note that Section 7.5.2 of these comments also highlights that EPA is aware of the potential challenges when storage vessels are connected in parallel and has made efforts in the past to try to address this situation.

Additionally, when there are multiple controlled storage vessels at a site (as affected facilities under Subpart OOOOa or covered by a state permit or other limit), they are typically tied into a single control device. That is, the vapors from the collection of storage vessels are collected in a common manifold and routed together to a single emission point, the control device. This fact creates further inconsistency and challenges with EPA's proposed approach for determining applicability as the air emission source in a traditional sense has shifted from a single storage vessel to a single control device associated with a group of storage vessels.

API believes that even the current approach to determining emissions for applicability is conservative since operators must consider only the first 30 days of production, and there is no allowance for a reflection of the reality that production from wells declines over time, often very quickly. API also expects that there would be limited environmental benefit from the proposed change as most new storage vessels that receive oil or condensate are being installed with controls. This issue is discussed further in Section 7.2.

Perhaps for certain lower production scenarios or situations involving low volatility crude, EPA's proposed changes could result in the controlling of vessels that would not otherwise have had them. However, even in this scenario, there would be very low environmental benefit from the controls (due to the low actual emissions). Further, in all likelihood, a situation such as this would result in vessels that will have actual emissions < 4 TPY VOC after just the first 12 months of production. Thus, controls could be removed after just one year and would, in hindsight, prove to have not been cost effective in the first place.

7.1.1 EPA's PROPOSED CHANGES ARE INCONSISTENT WITH POSITIONS TAKEN DURING THE ORIGINAL SUBPART OOOO RULEMAKING.

It is very difficult and impractical to measure throughput rates through individual storage vessels in a tank battery. EPA has recognized this in the preamble of the proposed Subpart OOOO rule, in proposed amendments to Subpart OOOO, and in EPA responses to public comments on those amendments. Provided below are two excerpts from EPA's Response to Comments document from the Subpart OOOO rulemaking. These excerpts clearly demonstrate that EPA has no intention to require the monitoring of flow to individual storage vessels under the rule. The proposed modifications to the definition of maximum average daily throughput in § 60.5430a certainly appear inconsistent with EPA's previously stated intent.

EPA Response to Public Comments, EPA-HQ-OAR-2010-0505-4546 (April 18, 2012), at 106-107 (Commenter 4178 – Laura Finley, ODEQ)

> *Comment: One commenter (4178) asserts that it is industry practice to not maintain records of the throughput of each individual tank; rather, total load out records are kept, which only show the total volume, rather than the volume at each individual tank. The commenter believes that*

> *putting the mechanisms in place to be able to track the totals at each individual tank, in addition to the reporting requirements, could prove to be a great burden on industry.*
>
> *Response: We do not believe that the concerns expressed by the commenter apply under the final rule. The final rule does not determine applicability based on throughput, nor does it require monitoring of throughput. Instead, operators are required to determine at the outset whether a new, modified or reconstructed storage vessel will have uncontrolled VOC emissions equal to or greater than 6 tpy and, if so, must install controls. The operator is not required to track VOC emissions thereafter.*

EPA Response to Public Comments, EPA-HQ-OAR-2010-0505-4546 (April 18, 2012), at 126-127

> *Comment: Several commenters (3560/4258, 4192, 4219, 4228, 4241, 4246, 4266) object to the requirement in the proposed rule to use flow meters to determine the annual throughput of storage vessels…*
>
> *Response: The final rule does not require the use of liquid throughput flow meters because the applicability of the storage vessel control requirements is determined based on annual VOC emissions, rather than liquid throughput as proposed. As discussed above and in section IX.E of the preamble to the final rule, we made this change in part because we are convinced that VOC emissions from stored fluids in the ONG industry are too variable to be regulated based on an average emission factor. Other factors in our decision to change the applicability metric include the issues raised by these commenters.*

Recommendation:

EPA should review the previously stated comments by the Agency (noted above) and re-evaluate whether clarifications are actually needed to the rule regarding storage vessel applicability.

If there are changes ultimately made to the rule, the word maximum has always added confusion with respect to calculating the average daily throughput and should be removed. It is more appropriate that average daily throughput be represented as the total throughput to an individual storage vessel over the 30-day evaluation period specified in § 60.5365a(e)(1) divided by 30 days.

7.2 Storage Vessel Applicability Should be of Little Concern When Emissions are Controlled

Feedback from API members indicates that the vast majority of new storage vessel batteries currently being designed and installed are equipped with a control device. As long as an operator is controlling storage vessel emissions at well sites or central tank batteries in compliance with "a legally and practically enforceable limit in an operating permit or other requirement established under a Federal, State, local or tribal authority," it matters little from an environmental perspective that the storage vessels are not subject to Subpart OOOOa compliance, recordkeeping and reporting requirements. In addition, states and operators have focused significant attention and resources to further address the appropriate sizing of storage vessel emissions control systems to ensure adequate handling of initial high production rates and peak flow from dump valves. It is also appropriate to note that, beyond general duty obligations that have always existed with respect to designing and maintaining equipment to minimize emissions, when new storage vessels are added to a site, it is generally associated with the addition of wells to the site. In that scenario, the fugitive components associated with the closed vent system for the controlled storage vessels would be subject to the Subpart OOOOa fugitive component requirements.

7.3 Restrictions on the Use of Legally and Practically Enforceable Limits by States, Tribes, or Local Agencies Violates the Concept of Cooperative Federalism

EPA finalized effective rulemaking when it provided the original language in § 60.5395 that allowed an operator to use a legally and practically enforceable limit to keep its storage vessels out of Subpart OOOO. This resulted in the vast majority of new and modified well sites opting to take these limits and incentivized the installation of storage vessel emission controls long before the applicability date of Subpart OOOO. EPA's proposed revisions undermine this incentive and compromise cooperative federalism.

The benefits of this approach are similar to the benefits realized previously with respect to 40 C.F.R. part 63, Subparts HH and HHH, where companies can establish limitations on benzene emissions through enforceable permit conditions to maintain dehydrator operations below levels that trigger the MACT control requirements under those rules.

Additionally, EPA's proposed revisions are wholly inconsistent with EPA's reliance on states to administer the Clean Air Act with regard to the Title V and PSD. That is, EPA allows states to establish emission limits on sites that keep sites below Title V and PSD permitting thresholds. This has long been an effective approach to reduce recordkeeping burden while directionally reducing potential emissions – the same goal being met with the original Subpart OOOO/OOOOa language and approach.

7.4 History of Subpart OOOO Storage Vessel Applicability Language

A brief look at the history of how the storage vessel applicability methodology and rule language evolved, from the August 23, 2011 proposed Subpart OOOO rule to the June 3, 2016 final Subpart OOOOa rule, further demonstrates that the newly proposed amendments are impractical and unnecessary. Underlined wording is emphasis added.

7.4.1 August 23, 2011 Proposed Subpart OOOO Rule and August 16, 2012 Final OOOO Rule

In the original proposal for controlling VOC emissions from storage vessels, in § 60.5365, EPA exempted storage vessels for which either (1) the annual average condensate throughput is less than 1 barrel per day per storage vessel, or (2) the annual average crude oil throughput is less than 20 barrels per day per storage vessel. As explained in the Best System of Emission Reduction (BSER) analysis on pages 7-18 through 7-21 of the July 2011 Technical Support Document. EPA intended to exempt individual storage vessels with less than 6 TPY of VOC emissions. EPA attempted to simplify the applicability method for facility owners by applying a fixed VOC flash emissions factor of 33 lb VOC/bbl of condensate and 1.6 lb VOC/bbl of crude oil. However, public commenters, principally API, noted that the 33 lb VOC/bbl emissions factor was much too high for most condensates and was based on a very flawed storage tank emissions study conducted for TCEQ. It was also pointed out that condensate and crude oil

VOC flash emissions factors vary greatly from basin-to-basin and field-to-field due to the variability of last separator liquid API gravity, composition, temperature and, especially, pressure operating conditions.

EPA received many public comments regarding the costs and impracticability of measuring liquid flow rates to individual storage vessels. (See EPA's Response to Public Comments on Proposed Rule August 23, 2011 (FR 52738)). Therefore, in the August 16, 2012 final rule, EPA revised the storage tank applicability language to a basic VOC emissions determination. In § 60.5365 (a)(1), for well sites with no other wells in production, EPA stated that "…you must determine the VOC emission rate for each storage vessel affected facility using any generally accepted model or calculation methodology within 30 days after startup…." In § 60.5395 (a)(2), for well sites with one or more wells already in production, EPA stated that "…you must determine the VOC emission rate for each storage vessel affected facility using any generally accepted model or calculation methodology upon startup."

In the rule preamble on page 49498, EPA addressed the reasoning behind the revisions to storage vessel applicability stating "For storage vessels ….with no wells already in production…, <u>the final rule provides a 30-day period from startup for the owner or operator to determine whether the magnitude o</u>f VOC emissions from the storage vessel will be at least 6 TPY" and "For storage vessels at well sites with one or more wells already in production….<u>these estimation and installation periods are not provided because an estimate of VOC emissions can be ma</u>de using information on the liquid production characteristics of existing wells."

It is obvious EPA intended for the 30-day evaluation period to simply be a time period for determining each storage tank's potential annual VOC emissions using any generally accepted model or calculation methodology.

7.4.2 JULY 17, 2014 SUBPART OOOO RECONSIDERATION AMENDMENTS: PROPOSED RULE AND DECEMBER 31, 2014 FINAL RULE

The proposed amendments for storage vessels were simply to (1) amend the provisions for determining storage vessel PTE when vapor recovery is being used for control, (2) add closed cover requirements for other mechanisms besides weighted lid thief hatches, and (3) slightly amend the requirements for storage vessels to clarify notification and other requirements for storage vessels that are removed from service. To that end, EPA proposed adding a definition of "removed from service" to § 60.5430.

However, without any public notice or public comment period, in the final rule EPA introduced the concept of storage vessels being returned to service and possibly being operated in "parallel" with existing storage vessels and how that affects VOC PTE for the two storage vessels. EPA also introduced the concept of calculating VOC PTE based on "maximum average daily throughput for a 30-day period." In the preamble, EPA stated that "Although we believe it is an unlikely occurrence, we note that, when two or more storage vessels receive liquids in parallel, the total throughput is shared between or among the parallel vessels and, in turn, this causes the PTE of each vessel to be a fraction of the total PTE. In these cases, the EPA would consider the parallel storage vessels equivalent to a single vessel with PTE equal to the sum of the PTE of the individual vessels."

EPA revised the definition of *storage vessel* to include the language that "Two or more storage vessels connected in parallel are considered equivalent to a single storage with throughput equal to the total throughput of the storage vessels connected in parallel." EPA also, without any justification, added a definition for "*maximum average daily throughput*" to mean "the earliest calculation of daily average throughput during the 30-day PTE evaluation period employing generally accepted methods." EPA also revised some of the storage vessel applicability language in § 60.5365 to include that "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."

After publication of the final amendments in the Federal Register on December 31, 2014, numerous upstream and midstream O&G companies and trade groups raised concerns about the storage vessel applicability revisions to EPA for: (1) being made final without public notice and comment; and (2) for EPA making assumptions about the operation of storage vessels connected in parallel and/or series without any understanding of how the storage vessels may be operated in practice. Specifically, on February 19, 2015, the Gas Processors Association (GPA) submitted a petition for administrative reconsideration of the December 21, 2014 amendments. The GPA asserted that "it is quite common for multiple storage vessels to be situated next to each other and connected in parallel. Sometimes the storage vessels are operated in parallel, sometimes they are operated in series, and sometimes they are operated one-at-a-time with the connecting valves closed." The GPA asserted this configuration has existed for decades and that "this language potentially has large impacts to how our members evaluate affected facility status."

7.4.3 March 23, 2015 Oil and Natural Gas Sector: Definitions of Low Pressure Gas Well and Storage Vessel: Proposed Rule and August 12, 2015 Final Rule

In response to the concerns raised by numerous companies and trade groups including GPA in its petition for reconsideration regarding the finalized revisions to storage vessel applicability language, EPA proposed "to amend the NSPS to remove provisions concerning storage vessels connected or installed in parallel and to revise the definition of "storage vessel". EPA discussed its original concern about storage vessels connected or installed in parallel in the proposed rule preamble and stated "For the reasons discussed above, we are proposing to remove the regulatory provisions relative to storage vessels 'installed in parallel' or 'connected in parallel.' Instead, we solicit comment on other approaches to help avoid or discourage installations or operation of storage vessels that would unnecessarily reduce the potential to emit (PTE) of a single storage vessel." On August 12, 2015, EPA finalized the revisions as proposed.

On pages 14 – 20 of the July 2015 Response to Public Comments on Proposed Rule (80 FR 13180): March 23, 2015), EPA responded to a number of public comments that provide information on EPA 's rational for removing the provisions concerning storage vessels connected or installed in parallel and revising the definition of "storage vessel."

7.4.4 September 18, 2015 Proposed Revisions to Subpart OOOO and Subpart OOOOa Proposal

In this action, EPA kept the method of determining storage vessel applicability as it was for the final Subpart OOOO amendments.

By keeping the storage vessel applicability language as it was for the final Subpart OOOO amendments, EPA reaffirmed (1) the use of "legally and practically enforceable limits" and (2) no language was necessary to address any concerns with whether storage vessels are operated in series or parallel.

8.0 PNEUMATIC PUMPS

API supports EPA's proposed removal of the "greenfield" site designation and the associated proposed revisions that allow the technical infeasibility determination associated with the control of an affected pneumatic pump at all well site locations. We agree with EPA's determination that this designation should be removed. There are, however, additional technical clarifications related to the pneumatic pump requirements that EPA failed to address:

- Explicit clarification that heaters and boilers need not be considered as either a control device or as "routed to a process" with respect to the requirements in § 60.5393a for pneumatic pumps. This is especially important when reviewing revisions made to § 60.5412a and § 60.5413a with respect to control of centrifugal compressors and storage vessels using a heater or boiler.
- Simplification of the technical infeasibility assessment to account for situations that are common to operators, including situations when control devices are owned and operated by a third party or presence of only a high-pressure flare.

8.1 HEATERS AND BOILERS

EPA has not addressed API's request to clarify how to handle boilers and process heaters with respect to the requirements to control pneumatic pumps by routing to a process or a control device.[31] By contrast, 40 CFR 63 Subpart HH and Subpart HHH include the following language under the definition of a "*control device*": "*For the purposes of this subpart, if gas or vapor from regulated equipment is used, reused (i.e., injected into the flame zone of an enclosed combustion device), returned back to the process, or sold, then the recovery system used, including piping, connections, and flow inducing devices, is not considered to be a control device or a closed-vent system.*"

By not providing this clarity with respect to pneumatic pumps under Subpart OOOOa, operators must review the technical feasibility of routing pump exhaust emissions to any small heater or boiler added at the well site per § 60.5393a(b)(3)(i) and maintain additional records. For many heaters/boilers used at well sites, the burner capacity will be insufficient to compensate for emission combustion of additional pneumatic diaphragm pump discharge due to their small size, which is generally 0.5-1.25 million BTU/hour. This may result in frequent safety trips and burner flame instability (e.g., ., high temperature limit shutdowns, loss of flame signal, etc.). There are additional safety concerns due to the intermittent, pulsating exhaust of gas when the pump de-pressures because this can cause problems for the pilot or fuel system. Additionally, industry guidelines (i.e., NFPA 86) would prohibit the use of boilers/heaters as control devices based on specific criteria including minimum operating temperature and presence of

[31] Under Subpart OOOOa, the provisions related to "control device" and "routed to a process" or "route to a process" are unclear with respect to controlling pneumatic pumps. These devices have additional requirements when controlling a storage vessel or wet seal centrifugal compressor that are not appropriate for the control of the intermittent emissions vented from a diaphragm pneumatic pumps.

emission source safety interlocks. Furthermore, small heaters and boilers are not inherently designed for control of emissions.

Consequently, boilers and heaters should not be considered "as routed to a process" nor as a control device with respect to the pneumatic pump requirements in § 60.5393a. We ask EPA to clearly provide this distinction under § 60.5393a(b)(3) to eliminate confusion with other requirements in the rule.[32] This will reduce the overall administrative burden by removing the recordkeeping requirements specific to certification of the technical infeasibility of using a small heater at well site with respect to control of pump emissions.[33]

Recommendation:

EPA should revise the rule language to clarify that, for the purposes of complying with the pneumatic pump provisions, heaters and boilers should not be considered as "routed to a process" or as a control device.

8.2 SIMPLIFICATION OF TECHNICAL INFEASIBILITY ASSESSMENTS

API submitted in our August 8, 2018 letter a request to simplify and reduce the administrative burden associated with conducting technical infeasibility assessments for situations that are pre-determined to meet the criteria listed in § 60.5393a(b)(5)(iii). If any of these situations were to occur at a well site with an affected pneumatic pump, operators would not be required to perform a full certification of infeasibility, but would document the cause of the infeasibility with respect to the common situations listed. This would alleviate undue burden associated with the technical infeasibility and certification requirements within this rule without posing any environmental dis-benefit.

- ***Exceedance of Maximum Rated Heat Capacity:*** The combustion device has a rated heat capacity that would be exceeded if the discharge of pump were to be sent to it.
- ***Operating pressure of the flare header exceeds the discharge pressure of the pump:*** If a high-pressure flare is installed to control emergency and maintenance blowdowns, it would not be technically feasible to route the low-pressure pump exhaust to the high-pressure flare because the operating pressure of the flare header exceeds the discharge pressure of the pump. For a flare to properly combust emissions and meet the destruction efficiency, the flare must be designed to manage either a high pressure or low pressure flow and for specific volumes being sent to it. A low-pressure exhaust would not adequately flow to the flare tip and result in inadequate

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[32] In § 60.5412a(a)(1) and (d)(1)(iv), states that introducing the vent stream into the flame zone of the boiler and heater would be using the boiler or heater as a control device. At the same time, § 60.5412a(a)(1)(iv) and (d)(1)(iv)(D),) requires the vent stream to be introduced with the primary fuel or use the vent stream as a primary fuel which would be routing the stream to a process. EPA has two conflicting requirements together in the same section. Inferring from the revisions in this proposal, 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. In §60.5413a(a)(3)), boilers/heaters are exempt 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) and (d)(1)(iv).

[33] If EPA continues to intend heaters and boilers be considered for reducing emissions from diaphragm pneumatic pumps, heaters and boilers should only be considered as process devices, which is inherent of their operational use;, with additional provisions streamlining the technical infeasibility assessment.

combustion of the exhaust. A separate flare would have to be installed to route the low-pressure exhaust from the pump which would not be cost-effective to install, as demonstrated in EPA's Regulatory Impact Analysis.

- ***Existing third-party control device on location:*** A company cannot legally route pump exhaust emissions to an existing third-party control device at a site. In addition, since the control device owner designs the equipment, the pump owner could not attempt to certify that the control device owned or operated by a third party is of sufficient design and capacity as specified in the certification requirements under § 60.5411a(d)(1). This is less likely to be an issue when a site location is being originally designed, but presents issues for existing locations where a new diaphragm pneumatic pump may be installed. Some examples of third-party control devices that an owner or operator of the pump could not route to include:
    - <u>Gathering Company Dehydration Unit Flare:</u> In some instances, a control device for the dehydration unit on a production site may be owned and operated by a gathering and collection system operator. In these instances, the well site operator does not have the right to route a pneumatic pump affected source exhaust to the control device.
    - <u>Reboiler for Dehydration Unit:</u> The reboiler for glycol dehydration unit and the dehydration unit may be owned or operated by the gathering company while the pump is owned by the production company. The production site owner would not have authority to route a pump to the dehydration unit reboiler.
    - <u>NGL Recovery Unit Flare:</u> There are instances where a natural gas liquids (NGL) recovery unit with a flare are owned by a third party, such as a gathering company, that is located at a production site with a pump that is owned by the production company.
- ***Presence of Small Boiler or Small Process Heater:*** Comment 8.1 outlines technical challenges with use of boilers and heaters with respect to control of a pneumatic pump. If EPA does not provide clarification for handling boilers and heaters with respect to control of pneumatic pumps, then simplification of the technical infeasibility assessment must be provided based on the stated technical considerations.

Recommendation:

EPA should reduce the administrative burden associated with conducting technical infeasibility assessments for situations that are pre-determined to meet the criteria listed in § 60.5393a(b)(5)(iii). Any of the following situations should be considered to represent common technically infeasible situations and such situations should not require further assessment: (1) Flare or other combustion device has a rated heat capacity that would be exceeded if the discharge of pump were to be routed to it; (2) Operating pressure of the flare header exceeds the discharge pressure of the pump; and (3) The control device is not owned and operated by the owner/operator of the pneumatic pump.

8.3 THE 90-DAY EXEMPTION BASED ON CALENDAR DAYS SHOULD ALSO ALLOW FOR 2,160 HOURS OF OPERATION IN § 60.5365A(H)(2)

API requests the use of a non-resettable run-time meter or automation to track hours of operation of a pneumatic pump to demonstrate that pumps that operate only occasionally operate less than 2,160 hours in addition to the current 90-day exemption. Allowing the use of a run-time meter or other automation to demonstrate operation below 2,160 hours per year would allow greater flexibility in documentation and better compliance demonstration that the pump runs less than 90 days a year. There are a number of pumps that might run for less than an hour every day or two, such as a water transfer pump. Such a pump would have very low annual emissions yet could still trigger the rule under the current language due to the nature of its operation.

EPA should maintain the current 90-day exemption in addition to this option. To be clear, 2,160 hours is the equivalent timing of a pneumatic to a pump that operates 24 hours per day for 90 days. EPA's background documentation established the 90-day exemption assuming 24 hours of operation of a pump based on a pump emission rate of 22.45 scf/hour (equivalent to assume emission rate of a diaphragm pump from the technical support document).

8.4 CROSS REFERENCE ISSUES IDENTIFIED FOR PNEUMATIC PUMP CLOSED VENT SYSTEM REQUIREMENTS

Although dependent on how pneumatic pump closed vent systems are handled in the final revision to Subpart OOOOa, API notes that there are numerous issues with the references to the closed vent system requirements proposed by EPA, including:

- There are no references to § 60.5415a and § 60.5416a found in § 60.5393a. Only § 60.5410a, §§ 60.5411a, and 60.5420a are referenced in 60.5393a and these sections do not reference 60.5415a or 60.5416a. This is very confusing because operators subject to pumps may not read these sections to know that they are subject to them if that, in fact, is EPA's intent.
- § 60.5415a(b) references both pumps and centrifugal compressors though the reporting requirements in § 60.5415a(b)(3) which include requirements that only apply to centrifugal compressors [including § 60.5420a(b)(3), § 60.5420a(c)(2), (7), (9), (10), and (11)]. API recommends that pneumatic pumps be split from centrifugal compressors in this section to make it clear the applicable reporting and recordkeeping requirements that apply to pneumatic pumps. Pneumatic pumps should only be subject to § 60.5420a(b)(1) and (8) and § 60.5420a(c)(6), (8), (16), and (17).
- Though it may be an oversight, § 60.5416a(b) still includes pneumatic pumps for the requirement to do Method 21 monitoring of the closed vent systems.
- Under § 60.5416a(c)(2), EPA has included reference to pneumatic pumps in the cover requirements listed in § 60.5416a(c)(2), although pumps do not have covers and are not subject to the cover requirements under § 60.5411a(b). We believe this is a cross-reference typographical error.
- There is no date upon which § 60.5416a(a) and (b) no longer apply and § 60.5416a(c) applies to the closed vent systems of pneumatic pumps. Therefore, it is unclear for operators whether or not sites already subject should change inspection methods for the closed vent system or keep using the existing method. Clear dates should be incorporated in the rule stating that it applies to existing Subpart OOOOa pumps and new as of publication of the proposal on October 15, 2018. EPA should also consider additional flexibility of assurance for pump CVS as discussed in Comment 10.0.

9.0 CERTIFICATION BY AN IN-HOUSE ENGINEER OR QUALIFIED PROFESSIONAL ENGINEER

9.1 IN-HOUSE ENGINEER OR QUALIFIED PROFESSIONAL ENGINEER CERTIFICATION CHANGES

API supports changing the requirement to require a qualified professional engineer for the CVS certification but the proposed changes to the rule to allow the use of an in-house engineer for certification still result in costs and difficulties in certifying:

- The technical infeasibility for routing pneumatic diaphragm pumps to a control device or process under § 60.5393a(b)(5), and
- The closed vent system (CVS) under § 60.5411(d)(1) for centrifugal compressor well seal fluid degassing systems, reciprocating compressors, pneumatic pumps and storage vessels.

Some challenges that will remain even with allowing an in-house engineer include the following:

- EPA has not defined in-house engineer, as to whether the engineer must be a full-time employee or could be a consultant working "in-house" for the company.
- Most in-house engineers and Professional Engineers (PE's) are not bonded and insured, thus are not willing to certify that they are *"aware there are penalties for knowingly submitting false information."* Some engineers fear that this statement could result in prosecution of individuals versus the company or the responsible official certifying the entire report.
- If an engineer (PE or in-house) did not design the whole system, they are unwilling to certify the CVS system. The new amendments are still not adequate.
- EPA underestimated the cost for an engineering certification as detailed in Comment 9.2

As stated in our December 8, 2017 letter to EPA, API maintains that a technical assessment of a closed vent system by a qualified engineer is an appropriate action for compliance assurance of the emission standards for storage vessels, compressors and pneumatic pumps. Documentation of this technical assessment should provide adequate compliance assurance that can be made available upon request to EPA. EPA should remove the certification statement in § 60.5411(d)(1)(i). The certification requirement and specific certification language that EPA includes in § 60.5411(d)(1)(i) presents numerous challenges and unintended costs beyond what EPA considered during this proposal. The certification process and statement itself does not add significant environmental benefit nor additional compliance assurance since there are provisions in place for ongoing compliance specific to the operation of closed vent systems, a general duty for all operators to minimize environmental impacts, and the annual report must be 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. The engineering certification statement does not relieve companies of this duty.
- The certifying official is already required to sign the report certifying the company's compliance with all applicable provisions.
- There are direct costs associated with the engineer certification process, whether companies support in-house licensure of engineers or leverage third parties.

- Engineering documentation showing that the closed vent system was properly designed or that a control was technically infeasible as part of the recordkeeping requirements should provide adequate compliance assurance. These records can be made available by request to the Administrator, as necessary.

Recommendation:

EPA should eliminate the certification statement in § 60.5411(d)(1)(i). If EPA retains the certification statement within the technical assessment, we request EPA should replace the descriptor of "in-house" to allow an engineer with knowledge/oversight of the system design. EPA should review the certification language with respect to liabilities for the engineer providing the assessment. The certifying official is already required to attest to their company's compliance with all applicable provisions. Any inclusion of discussion of liabilities for the engineer themselves only confuses EPA's intent that a professional engineer is not required.

9.2 EPA UNDERESTIMATED THE COST OF AN ENGINEERING CERTIFICATION

API members report costs ranging from $2,000 - $9,000 per certification; with actual cost dependent on the site complexity and, thus the amount of engineering design time involved. EPA estimates each certification by a professional engineer would cost only $547 and an in-house engineer would cost only $358. These costs are based on only four hours of staff level engineer time for the in-house engineer and on only two hours of work by a professional engineer. This level of cost does not match the inherent time required to have knowledge of the system prior to the certification; especially given the language and liability included within the certification language.

10.0 CLOSED VENT SYSTEM AND COVER REQUIREMENTS

API appreciates that EPA has made efforts to propose changes to the pneumatic pump closed vent system requirements versus requiring annual Method 21 inspections of the pump closed vent system. EPA has proposed to align pneumatic pump CVS inspections with the requirements for storage vessel CVS inspection. API has discussed different approaches to the pump CVS requirements with EPA and would like to clarify our position.

- API request EPA further increase flexibility pertaining to the closed vent system requirements for pneumatic pumps by allowing the option to perform monthly AVO inspections or allow annual OGI or Method 21 inspections.
- API requests simplification of the recordkeeping and reporting requirements for the CVS inspections. Consistent with our position on other recordkeeping and reporting, EPA should focus on the most important elements and not require data that does not provide direct value.

10.1 EPA SHOULD INCREASE FLEXIBILITY IN PNEUMATIC PUMP CLOSED VENT SYSTEM INSPECTIONS

Unlike closed vent systems that are used to route storage vessels to a control device, a closed vent system with respect to control of pneumatic pump emissions is simply a hard piece of pipe with connectors or flanges. While the technical feasibility of routing pneumatic pump emissions to a control device presents many technical challenges, as described in previous comments, once the pump is routed to a control device through a closed vent system, the closed vent system itself is fairly simple in design. Given the simplicity and low potential for leaks or defects along the piping, EPA could and should allow increased flexibility in implementation of the no-detectable emission limit along this piece of pipe by allowing multiple options to perform inspections including monthly AVO, annual OGI, or annual Method 21. EPA has considered OGI an equivalent method under the leak detection and repair requirements and the hard piping of the closed vent system for the pump for defects can be performed the same as looking at fugitive components.

Practically speaking, for sites where monthly AVO is being performed on an affected storage vessel, many companies would prefer to do monthly AVO. For sites subject to Subpart OOOOa leak requirements and no Subpart OOOOa storage vessels, companies are more likely to prefer to conduct annual OGI inspection.

Recommendation:

EPA should further increase flexibility pertaining to the closed vent system requirements for pneumatic pumps by allowing the option to perform monthly AVO inspections or allow annual OGI or Method 21 inspections.

10.2 Simplify Recordkeeping and Reporting from Monthly AVO

EPA is requiring that operators collect and report a great amount of information for closed vent system AVO inspections. This data collection increases the time that it takes to do these inspections and increases burden of such inspections without providing a clear environmental benefit. API requests that the reporting requirements for both storage vessels (in § .605420a(b)(6)(ix)) and pumps (in § 60.5420a(b)(8)(iv)) be eliminated and not finalized as proposed.

API requests that the recordkeeping requirements be further simplified, consistent with previous comments, and limited to the following:

- Site ID
- Date of the inspection;
- Number and type of defects identified;
- Number and type of defects that were not repaired as required; and
- Number and type of defects placed on delay of repair and explanation for each delay of repair.

API also requests that EPA remove the requirements for recordkeeping under § 60.5420a(c)(6), (7) & (8) and reporting under § 60.5420a(b)(8)(iv) for pumps for covers because pneumatic pumps do not have covers and are not subject to § 60.5411a(b). We believe this is likely a typographical error in the proposed rule.

11.0 WELL COMPLETIONS OPERATIONS

11.1 API SUPPORTS CLARIFICATIONS REGARDING SEPARATOR LOCATION AND DEFINITION OF FLOWBACK; SEEKING ADDITIONAL CLARITY IN PROPOSED DEFINITIONS

We support EPA's proposed clarifications regarding well completion operations in § 60.5375a(a)(1)(iii) that explicitly allow use of nearby separators during flowback and provide the distinction that certain activities that occur prior to flowback including screenouts, plug drill outs and coil tubing cleanouts are not intended to be part of flowback as defined. There are additional minor clarifications required with respect to the newly proposed definitions for these activities as follows:

- *Coil Tubing Cleanouts* include mechanical methods to remove solids and/or debris from a wellbore. The process where an operator runs a string of coil tubing to the packed proppant within a well and jets the well to dislodge the proppant and provide sufficient lift energy to flow it to the surface.
- *Plug Drill-outs are* the removal of a plug (or plugs) that were used to isolate different sections of the well.
- *Screenout*s are attempts to clear proppant from the wellbore in order to carry the proppant out of the well.

11.2 PROPOSED DEFINITION OF PERMANENT SEPARATOR

In § 60.5420(b)(2) and (c)(1), EPA introduces the term "*permanent separator.*" The definition EPA provides in § 60.5430a for *"permanent separator"* describes temporary actions, which is contrary to the inherent meaning of the word permanent. Specifically, EPA defines the usage of the permanent separator as handling flowback between the initial flowback period and the startup of production, which is temporary in nature.

Recommendation:

To mitigate confusion on the flowback requirements, API suggests not finalizing the proposed definition of permanent separator and removing reference of the term for purposes of recordkeeping and reporting § 60.5420(b)(2) and (c)(1). The completion log requirements would not require a separate category since the daily log includes the time period described in this definition.

11.3 RECORDKEEPING AND REPORTING FOR COMPLETION OPERATIONS THAT IMMEDIATELY START PRODUCTION SHOULD BE SIMPLIFIED

In some locations, operators are able to start production immediately following well cleanup activities. In these cases, the flowback period, including both the initial flowback stage and separation flowback stages as defined in § 60.5430a, is bypassed and the well immediately starts production following well cleanup activities. For wells where it is possible to immediately start up production, we request simplification of the recordkeeping and reporting burden associated with maintaining the daily completion log. The simplification of these records is requested to reduce administrative burden since the daily completion log information is not relevant after startup of production.

Recommendation:

For well completions operations that immediately start production, API recommends that EPA only require the following for recordkeeping and reporting: 1) the United States Well Number, 2) the Well Completion ID, 3) Identification that the well immediately starts production (i.e. there is no initial flowback stage or separation flowback stage), 4) the date of startup of production (in lieu of Date of Onset of Flowback Following Hydraulic Fracturing or Refracturing).

12.0 OTHER TOPICS

12.1 THE EQUATION DEFINED FOR CAPITAL EXPENSE REMAINS UNREPRESENTATIVE OF CURRENT ECONOMIC CONDITIONS.

API believes that the definition of Capital Expenditure (and the equation listed in Subpart 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. As we stated in our December 4, 2015 comments, the equation proposed by the EPA unrepresentatively overstates the effect of inflation in terms of discounting the value of B. We maintain that a Consumer Price Index (CPI) based equation is more appropriate for use in discounting inflation in current economic conditions.[34] API proposes that EPA use a CPI based equation to discount B (valued at 4.5% for our industry) as shown: Y = (CPI of date of construction or reconstruction/CPI of date of component price data).

An example of the effect of the improper use of inflation is that gas plants that are built after 1982 trigger "modification" with as little as a single valve added to the process unit. Many times these process units may require large replacements of "equipment" (as defined in the regulation) to comply with this change and permanent plant shutdowns may occur as a result because these replacements are uneconomic.

We incorporate by reference the following docket previously submitted to EPA by GPA on this issue. https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-7237 (page 42).

[34] Refer to Comment 16 in API's December 4, 2015 Comment letter at EPA-HQ-OAR-2010-0505-6884

Attachment A
API's Response to EPA's Analysis of Well Site Fugitive Emissions Monitoring Data

API's Response to EPA's Analysis of Well Site Fugitive Emissions Monitoring Data

Memo dated April 17, 2018
EPA-HQ-OAR-2017-0483-0036

EPA released a memo summarizing the Agency's review and analysis of the leak detection and repair (LDAR) data submitted by API in early 2018 (see Docket: EPA-HQ-OAR-2017-0483). EPA's memo discusses their view of data uncertainty associated with the data provided and presents EPA's rationale for why these uncertainties contribute to the inability of EPA to rely on the data directly with respect to the current proposed amendments. API members collected leak detection data from over 4,000 well sites across the country and submitted these data to help the Agency better understand trends with actual leak incidence occurring at well sites. API believes EPA's analysis and conclusion that the data cannot be relied upon is flawed for several reasons as detailed below by topic.

Additionally, the tone and content of EPA's memo suggest inherent bias by the agency. That is, the Agency's analysis implies that there must be flaws in the dataset as the results represented lower leak rates than EPA appears to have expected. This inference is particularly concerning as no data or explanation for EPA's expectations are provided. The data relied upon by EPA in developing its estimates for leaks from well sites comes from the 1995 EPA Leak Protocol document were values based on a small sample size of oil and gas operations. The 1995 Protocol was also derived from oil and gas facilities whose designs are expected to be significantly different than modern sites subject to Subpart OOOOa.

A. EPA Concern with Uncertainty of Well Site Age

Summary of Issue: EPA's stated concern is that the dataset did not provide the age of the wells. EPA asserts new wells *"could be expected to have a lower-than average incidence of fugitive emissions because components have not yet experienced degradation via wear and tear or lack of maintenance."*

API Response: API does not agree with EPA's assertion, but more importantly, we do not understand how this is a limitation to the data provided. By nature, New Source Performance Standards, like Subpart OOOOa, are directed at new and modified sources. Our dataset was focused on providing the initial leak incidence rates being observed by members at the type of facilities that EPA has regulated under Subpart OOOOa.

If EPA truly believes new well sites are expected to have lower than average leak incidence, this would directly conflict with EPA's reasoning for requiring new sources to perform leak detection within 60 days of startup. We would further question how EPA has estimated the baseline emissions for new well sites within their cost-effectiveness analysis since the model plants do not distinguish between new and modified locations. Furthermore, by EPA's logic, any inclusion of older wells undergoing the first OGI survey in API's dataset would only provide a higher than "average" initial leak incidence than a collection of only new wells. This would infer API's data is conservative with respect to types of well sites subject to the NSPS.

B. EPA Concern with Uncertainty of OGI Procedures and Environmental Conditions During Surveys

Summary of Issue: EPA expresses concern about the specific methods used in conjunction with the OGI surveys that led to the API dataset and concludes: *"Without standardization of monitoring procedures, or knowledge of which programs this initial monitoring was conducted under, it is not possible to determine the quality of the monitoring data and whether the survey operator accounted for environmental conditions and interferences during the survey."*

API Response: It seems EPA is expecting wide variability in the environmental conditions when OGI is used and thus, even though this dataset is large, such variability is so great that the average of the data is not useful. API believes this position is unreasonable and overly pessimistic with respect to the ability to use OGI instruments. While API appreciates the potential variability between equipment and the exact methods used in conjunction with the OGI camera, many of the survey data provided were collected under compliance obligations, either under Subpart OOOOa directly and/or another state program. API also believes that the dataset is quite large and covers many geographies and operators and is superior to the small dataset behind the 1995 EPA leak protocol document. Furthermore, it is difficult to understand how EPA can make these statements with respect to the OGI data provided by API and, in the same proposed rulemaking, rely upon OGI data collected through a helicopter survey in order to make assumptions specific to thief hatches and pressure relief valves.

With respect to environmental conditions and interferences, EPA states that lack of knowledge on wind speed and weather conditions effectively limits the use of the data provided. First, not all state programs have required capturing this type of information and therefore, it does not exist for some of the survey data. Perhaps more importantly, while API understands that Subpart OOOOa requires capturing this information, the fact is that EPA does not have any quantifiable method to include or exclude data based on it. Therefore, the assertion that the data cannot be used because the wind speed and weather condition information is missing is unreasonable.

While certain conditions, such as high wind speed, can make it more difficult to identify small leaks, operators are unlikely to perform surveys during high winds (and other limiting conditions). API believes it is also important to acknowledge that study after study shows that the majority of emissions come from the largest leaks. Even if one were to accept EPA's inference that some small leaks were missed during surveys, the mass of such leaks would have little impact on the overall expected emissions.

Lastly, industry has invested extensive resources in the use of OGI cameras. The cost to implement a leak detection and repair program is not insignificant. It is impractical to assume that companies are not properly using the technology after making such high investments in equipment and manpower.

C. EPA Concern with Uncertainty of Universe of Components Monitored

Summary of Issue: EPA expressed concern about whether or not all the components covered by Subpart OOOOa were surveyed since not all surveys were performed under the NSPS.

API Response: API member companies indicate that their staff and contractors generally make a record of all leaks identified during OGI surveys. Reasons for this include:

- A desire to not confuse staff completing the surveys with regard to what components are to be surveyed under different regulatory programs, and operators want to get the maximum benefit of mobilization for a given survey.
- Companies want to know that identified leaks are repaired to capture the natural gas for sales.

API believes that the universe of components in our dataset is, on average, more exhaustive than the components covered by Subpart OOOOa. Additionally, EPA's concern about the universe of components that are monitored may be coming from a different industry context. For example, a refinery or chemical plant will have components and entire sections of facilities that are not subject to LDAR under federal regulations. This is because certain streams may be low in VOC content and, therefore, are not subject to monitoring. For oil and gas well sites and compressor stations, there is no such applicability criteria. This means all the components at a well site or compressor station are subject to the leak survey. While closed vent systems under Subpart OOOOa undergo separate compliance measures through implementation of separate inspections, operators do not typically distinguish these components separately when using the OGI for reasons stated above, i.e. operators seek maximum benefit for conducting leak surveys.

D. EPA Concern with Uncertainty of Production Rates of Well Sites

Summary of Issue: There is no information provided on the production rates of the well sites included in the dataset and EPA did not want to misapply the data.

API Response: Production data are not easily associated with leak data based on the recordkeeping associated with leak detection surveys. In the absence of information on wells that are low production, we assumed all well sites in our dataset produce more than 15 barrels of oil equivalent per day.

E. EPA Concern with Uncertainty of Equipment Counts

Summary of Issue 1: EPA expressed concern about the accuracy of API's data, stating: *"Of the 4,117 well sites included in the dataset, only 95 of these well sites had known equipment counts. Equipment counts for the remaining 4,022 well sites were estimated using the default average component counts for onshore natural gas and crude oil production equipment listed in 40 CFR part 98, subpart W, Tables W-1B and W-1C."*

EPA goes on to state: *"Additionally, the counts in subpart W do not accurately reflect the entire universe of components that could be present at a well site. For example, for natural gas production equipment, Table W1B only lists estimated counts for valves, connectors, open-ended lines, and pressure relief devices on wellheads, separators, piping, compressors, heaters, and dehydrators. It does not include sources like storage vessels, where thief hatches would be a potential source of fugitive emissions."*

API Response to Issue 1: API is concerned by EPA's logic on the use of estimating components in the above statements for several reasons:

1) EPA has mis-categorized the data. There were 95 well sites that had a known level of actual components stated. We believe this was a typo in the memo. As EPA states, the additional 4,022 sites used known equipment counts to estimate the number of components using a

generally accepted approach that EPA has established under the Greenhouse Gas Reporting Program at 40 C.F.R. part 98, Subpart W.

2) The component count methodology under Subpart W have been the basis for the GHG reporting rule for several years, so it seems inappropriate for EPA to assert that the methodology is inadequate in estimating number of fugitive components.

3) While EPA infers it was inappropriate for API to use these Subpart W component factors in our analysis, these are the same component factors EPA uses in the development of the model plant. We fail to understand how our application of these factors in estimating components based on known equipment at our well sites is different than EPA's methodology of establishing the number of components at the model plants using the same factors.

4) By EPA's stated example, the component counts provided in our dataset are estimated lower than what EPA feels might be representative, indicating our data were conservative. In other words, the leak incidence values in the dataset would be even lower when these additional components are added to each well site; in addition to the Subpart W factors already estimated.

5) We reviewed the average components based on the actual equipment listed in our data compared to the average number of components EPA had used during the final rulemaking in Subpart OOOOa (which were available during the time the API data was compiled). While our data show slightly higher components for Oil Wells Associated with Gas, our gas well sites contain, on average, about 100 less components than EPA's gas well site model plant for the final rulemaking.

   We also note that EPA has reduced the number of estimated component counts in their newly released model plant for both gas well and oil well sites. This directly conflicts with EPA's stated concerns that our dataset had underestimated the total number of components with respect to estimating the leak incidence.

EPA Model Plant Categories in Final Rule	**EPA Model Plant Components in Final Rule**	**Average Components from API Data**	**Model Plant Counts in Proposed Rulemaking**
Gas Well Sites	671	580	610
Oil Well Sites (GOR < 300)	127	Not applicable, data only include light crude oil wells with associated gas.	127
Oil Well w/ Associated Gas (GOR > 300)	314	347	257

Summary of Issue 2: *"An estimated component count will likely bias the leak rate, as the leak rate is directly correlated to the number of components present and monitored. Whether the leak rate is biased high or low would depend on whether the fugitive components are over or under estimated."*

API Response to Issue 2: We agree the total number of components at the site is an important factor when considering the overall leak incidence rate. In this context, a site with only 40 total estimated components should not be equally compared to a location with 1,000 estimated total components. To account for this variation, we applied a weighted average to specifically account for the number of total components estimated at the site. We continue to maintain that this was a correct approach and one that directly addresses the variation and uncertainty in using estimated component factors. We discuss this more in our response to EPA's concerns with the calculated leak rates.

Summary of Issue 3: EPA states, "*Furthermore, because the equipment counts do not include components like thief hatches, it calls into question whether these types of components were monitored during the surveys. As previously discussed, the presented information is limited as to whether the universe of fugitive emissions components required under the 2016 NSPS OOOOa were monitored during the surveys, potentially biasing the leak rates; the equipment counts further reinforce this concern."*

API Response to Issue 3: As discussed in API's response to Section C above, the assertion that API members are not surveying all potential fugitive components is unfounded and is simply inaccurate. Further, the methodology used to determine an estimate of total components at a well site does not influence or impact the number or type of leaking components identified within the leak records. For EPA to make any linkage or assumption between the approach to estimate the number of components and the count of leaks identified is unfounded. Our analysis included review of records maintained when conducting initial leak surveys at 4,117 well sites. We then paired this information with separate records that describe the number and type of equipment located at these well sites. Information regarding equipment to estimate the number of components of these sites based on an approach developed by EPA to estimate fugitive components. This was a large undertaking by member companies to collect and organize data in order to present information in, what was believed to be, a useful format for the Agency.

F. EPA's Concern with the Uncertainty of Zero-leak Rates

Summary of Issue: EPA claims the dataset contained an unusual number of well sites reporting no fugitive emissions during the monitoring surveys. "*Of the 4,117 well sites, 44% reported no fugitive emissions. This extremely high percentage of well sites with a zero-leak rate reinforces concerns related to the proper use of OGI and the need for standardization in the way that OGI is performed in monitoring surveys, as previously discussed."*

API Response: EPA asserts the zero-leak findings in our data are unusually high but does not present any basis for this claim. Our data is based on real world results of implementing leak detection and repair program at well sites which are indicative of the locations subject to the NSPS. We have submitted multiple rounds of data in various formats that continue to show this similar trend. These statements are troublesome as they express a level of bias by the Agency with respect to our operations and have no supporting merit for comparison. We also disagree that more stringent standardization of OGI procedures would show different results. Each monitoring survey is conducted to ensure all components are surveyed EPA continues to erroneously equate the sources at well sites and compressor stations covered under

Subpart OOOOa with sources covered by traditional LDAR programs such as chemical plants and refineries, which are large, complex facilities containing tens of thousands or more components. These facilities require a team of full-time dedicated staff on-site to manage the significant demands associated with running a “traditional LDAR” program. This is very different from managing surveys containing a relatively small number of total components at hundreds (and eventually thousands) of un-manned, remote production facilities.

G. EPA’s Concern with Leak Rates

Summary of Issue 1: EPA believes a weighted average does not address the average leak rate at individual well sites.

API Response: By definition, a weighted average is similar to a straight average except that instead of each of the data points contributing equally to the final average some data points contribute more than others. As we discuss above, we believe variation in the total number of components at the well site is an important factor to be considered when reviewing the leak incidence in appropriate context. In fact, we have previously submitted comments asking that sites with less components than what EPA estimates in the model plant be exempt from leak detection programs because of this issue.

Some specific points about our data based on statements by EPA:

- There was one state, Ohio, where out of 37 locations surveyed, no leaks were identified. First, we point out that the Pennsylvanian Basin (Eastern Overthrust Area) includes portions of Ohio. EPA should consider that some Pennsylvania Basin wells may be located in Ohio and review the data in its entirety. Second, all of these locations were identified as single gas well sites containing separators, heaters and some piping. These locations each have an estimated total components count less than 200. Based on the equipment located at these sites, we do not find it unreasonable to assume no leaks were found based on the equipment identified. Lastly, we continue to point out that operations at well sites are vastly different than what EPA might expect at larger, more complex facilities.
- Well sites in Alaska average around 30 wells per well site compared to EPA’s model plant of only two wells. The total component counts we estimated at these well sites are, therefore, likely underestimated for these assets. This means the leak incidence calculated for these locations is overly conservative in its estimation.

Summary of Issue 2: EPA states a 1.18% leak incidence was assumed at well sites.

API Response: EPA assumed that 1.18% percent of components, or four components, were leaking in order to estimate the count of components that would require repair. With respect to quantification of baseline emissions, EPA applied emission factors to the population of components within the model plant, i.e. the emission factor was multiplied against all components at the well site. That is, EPA did not estimate baseline emissions assuming only four components leak at the site. It is misleading for EPA to continue to make erroneous statements with respect to the number of leaks assumed in their analysis and their associated emissions.

Figures 5-16 through 5-34 of the EPA Leak Protocol clearly demonstrate that the emission factors within Table 2-4 correspond to a specific fraction (or number) of components that are assumed to be leaking. To make this point clear, Figure 5-25 from EPA Leak Protocol is provided below for reference and depicts this correlation between emission rates and leak incidence rates.

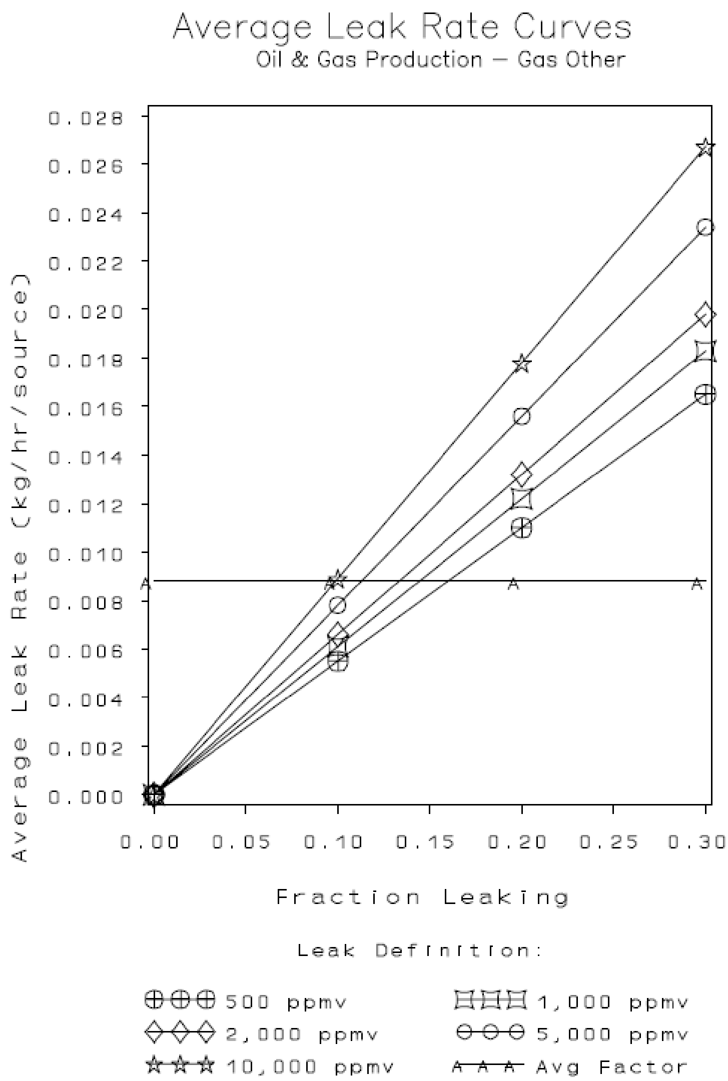


Figure 5-25. Oil and Gas Production Gas Other Average Leak Rate Versus Fraction Leaking at Several Leak Definitions

As Figure 5-25 clearly depicts, the average leak factor from Table 2-4 for "other" equipment at gas production sites is 8.83 E-03 kg/hr/source, as demarcated by the horizontal line. This emission rate directly corresponds to a fraction of leaking components that ranges from nearly 0.1 to 0.16 (or 10 to 16%) of "other" components, depending on the leak definition applied. Similarly, one can look at the Figures in Chapter 5 of the EPA Leak Protocol and determine the fraction of all component types that are assumed to be leaking when one uses the Table 2-4 factors to represent a population of components. Each component type (connectors, flanges, open-ended lines, etc.) has a different assumed leak fraction embedded within the average emission factor rate.

The following table summarizes the fraction of leaking components assumed within the Table 2-4 Emission Factors based on a leak definition of 500 ppm and 10,000 ppm.

Type of Component	***Original EPA Basis for Emissions from Leaks (Table 2-4):*** **(kg/hr/comp)**[1]	**Percent of Components Leaking @500 ppm using Table 5-7 correlations**	**Fraction of Components Leaking @10,000 ppm using Table 5-7 correlations**
Valves	0.0045	6.42%	4.57%
Flanges	0.00039	0.90%	0.47%
Connectors	0.0002	1.20%	0.73%
OEL	0.002	5.39%	3.61%
PRV	0.0088	15.97%	9.75%

Using the figures and correlation equations within the EPA leak protocol, one can calculate that, for the EPA model facility assumed in the 2016 Subpart OOOOa rulemaking, EPA actually assumed between 1.6% and 2.5% of components at a model well site were leaking, depending on the leak threshold used to define the leak. The lower value represents an assumed 10,000 ppm Method 21 leak definition and the higher value assumes a 500 ppm leak definition, which is the leak definition finalized within Subpart OOOOa.

We also note that the analysis EPA developed in support of the 2018 Subpart OOOOa proposal for thief hatches follows a similar process to arrive at a new emission factor. The new emission factor for thief hatches is based on newly available data, and similar to the Table 2-4 factors, the newly proposed emission factor represents yet another assumed leak fraction for that particular component type.

H. Response to Emission Rates

Summary of Issue: EPA does not agree with the approach within the analysis to apply correlation factors from the EPA protocol document because the data is based on Method 21 data and not on OGI. EPA makes the following statements about the correlations in the EPA Leak Protocol: "*The equations in Table 5-7 are based on specific leak definitions when using Method 21. These equations do not apply to monitoring using OGI… Even using the most conservative of the equations in Table 5-7 does not provide reasonable accuracy because OGI data is not expected to correlate point-by-point to Method 21 data. If it were possible to develop equations for OGI, they are unlikely to resemble the equations in Table 5-7. Additionally, as previously noted in Section 4.0 of this memorandum, we did not use these equations to determine the leak rate for OGI. Since we didn't determine the leak fractions from the equations in Table 5-7, we do not believe it is appropriate to scale the emissions factors that we used with the leak fraction back calculated from the equations in Table 5-7.*"

API Response: EPA does not oppose the approach in our analysis, but rather, only opposes its application to OGI data. EPA's rationale for dismissing our analysis on the basis that data within the EPA Leak Protocol are based on Method 21 data contradicts EPA's own approach within the model plant analysis that applies emission factors based on the same data. Specifically, EPA relied upon the general oil and gas leak emission factors from the 1995 Protocol for Equipment Leak Emission Estimates that are summarized in Table 2-4. As discussed above, these emission factors were developed from Method 21 data and applied to all components within the model plant as a representation of average leaks across all components within a population with an unknown initial leak incidence. The same application of the emission estimating methodology was applied for the model plant cost-benefit analysis for both Method 21 and OGI as EPA did not use separate emission factors to quantity baseline emissions based on leak detection techniques.

Further, it is noted that both the emission factors in Table 2-4 and the correlation equations from Chapter 5 of the EPA Leak Protocol are derived from Method 21 data – in fact, both the factors and collection of equations come from the very same Method 21 data. EPA did not rely upon the correlation equations in Chapter 5 directly. However, EPA did, in fact, rely upon Method 21 based emission factors to estimate the emissions from well sites that would be subject to OGI by relying on Table 2-4.

API did not object to the use of Table 2-4 in the original rulemaking as it was the best available data at the time. However, now that large amounts of data are available and are indicating that, for the average site, EPA has over-estimated the fraction of components leaking, It is both appropriate and necessary to reflect that in determining what frequency of leak survey is cost-effective and the net benefits that will actually be realized through implementation of Subpart OOOOa.

Recognizing that there are no correlation equations yet developed for OGI similar to what exists for Method 21, API reminds EPA of its determinations made during the Subpart OOOOa rulemaking when establishing Method 21 as an alternative to OGI, which was determined to be BSER:

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

In other words, there is a high confidence that OGI will identify leaks over 10,000 and, in many cases, will also identify leaks at lower concentration levels. API therefore believes that applying EPA's Method 21 correlation equations, based on a 10,000 ppm Method 21 leak threshold and a known leak incidence, is justified. In fact, it is a conservative approach since, in most conditions, OGI will identify leaks that are less than 10,000 ppm, thereby increasing the incidence rate for identification of leaks.

Further, we believe that, in absence of emission factor correlation data specific to OGI, the approach we used to derive more representative emission factors based on the known incidence rate is appropriate given EPA's usage of similar Method 21 based data within the protocol and further detailed in the above comment on leak incidence rate.

API appreciates the opportunity to discuss approaches for updating EPA's analysis in light of the data we have provided and additional data we expect to provide from Subpart OOOOa surveys.

Attachment B

API Analysis of Subpart OOOOa Semi-Annual Leak Survey Data

API Initial Analysis of Subpart OOOOa Fugitive Emissions Monitoring Data

December 17, 2018

As a follow-up to our review of the data API provided to EPA in early 2018, API undertook a recent effort to collect Subpart OOOOa data from member companies to understand how data collected under the rule might differ from the broader dataset previously provided to EPA. The reported Subpart OOOOa data include data from both the initial and second reporting period and show trends that are entirely consistent with API's earlier dataset and analysis. Specifically, the Subpart OOOOa data show:

- There are large number of sites that have no leaks (58% of initial well site surveys).
- The average number of leaking components per site is less than 2 components found leaking during the initial Subpart OOOOa survey and falls quickly to less than 1 leaking component found on average in subsequent surveys. Both values being well below the 4 fugitive components that EPA assumed would require repair in each survey and even further below the number of leaks assumed in the EPA Leak Protocol Table 2-4 emission factors that were used to estimate emissions.

These data confirm that EPA's initial assumption regarding the number of components leaking at well sites (and the corresponding mass of emissions) was significantly overestimated. API further believes that an evaluation of this data and any larger datasets from Subpart OOOOa data will confirm that a semi-annual survey frequency is not necessary or cost-effective for well sites.

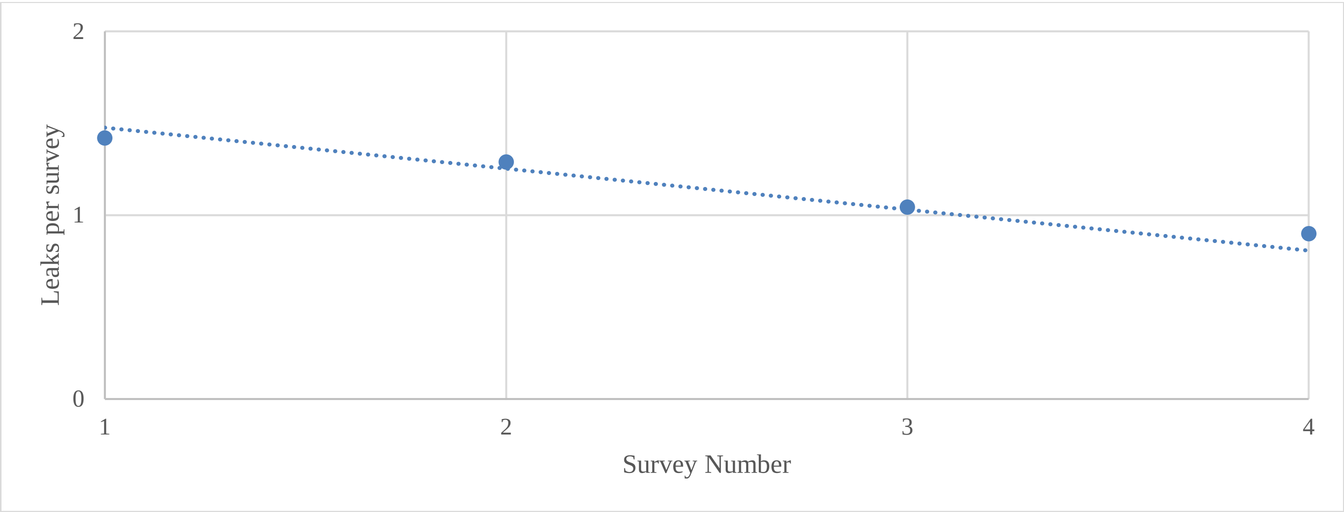
The remainder of this document provides an initial summary of the Subpart OOOOa dataset evaluated by API. API is continuing to analyze the data and welcomes the opportunity to discuss the data with EPA.

Summary of Leak Survey Dataset

- Two years of Subpart OOOOa Leak Survey Data for Sites Monitored at a Semi-Annual Frequency
- Over 6,000 total surveys across 3,482 sites
- Represents data from 13 different operators
- Surveys performed at sites located in: Kansas, Louisiana, North Dakota, New Mexico, Ohio, Oklahoma, Pennsylvania, Texas, and Wyoming
- For Initial Surveys at Sites Monitored at Semi-Annual Frequency – 58% of initial surveys found no (0) leaks
- Average number of leaks found per site = 1.42 for first survey and declines for subsequent surveys.

The following graphic illustrates the average count of leaks found per leak survey. As can be seen, the count of components found leaking averages around 1.4 components and steadily declines with each subsequent survey. While there is a decline over time as one would expect, the key observation from the data is that there are very few leaks being detected, on average, even during the initial leak survey.

Figure 1. Average Count of Leaks Found per Leak Survey Monitored per § 60.5397a



The table below summarizes the number of semi-annual survey data by company.

Company ID	Number of Leak Surveys
AA	904
BB	79
CC	156
DD	63
EE	1070
FF	497
GG	552
HH	39
II	730
JJ	121
KK	317
LL	727
MM	765

The table below summarizes the number of sites and leaks available from semi-annual survey data by survey number.

Survey Number	Total Number of Leak Surveys	Total Number of Leaks	Leaks per Survey
1	3,367	4,779	1.42
2	1,776	2,290	1.29
3	721	752	1.04
4	119	107	0.90

Summary of Findings

Figure 2 below illustrates the distribution of the number of leaks found during initial and subsequent semi-annual leak surveys. Observations from these data:

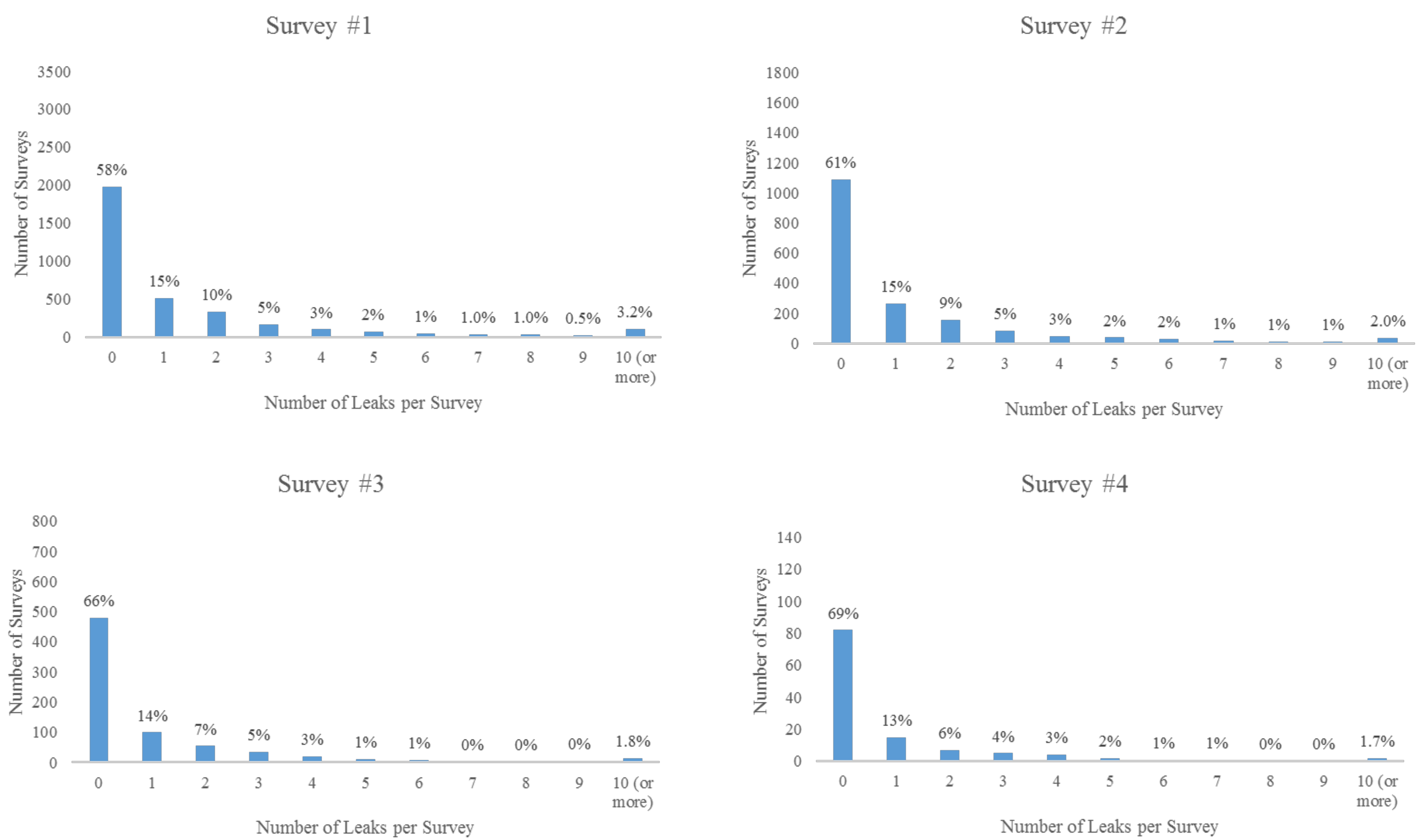
- A large percentage sites have no or very few leaks.
- With subsequent surveys, the percentages of sites with 0 or 1 leaks increases and the percentage of sites with 2 or more leaks decreases.
- Notably, while 3.2% of sites found 10 or more leaks in the initial survey, the percentage of sites with 10 or more leaks in subsequent surveys declines, going from 3.2% to 2.2% by the second survey and to 1.8% of sites by the third survey.

Conclusion

The Subpart OOOOa data described above confirm that the vast majority of well sites have very few leaking components – 92% of surveys identified 4 or less leaking components – with over half the surveys identifying no leaking components at all. In fact, approximately 60% of all surveys did not find any leaks. These data also are consistent with API's previously submitted data and confirm that EPA overestimated the number of leaking components at the average well site used within the model plant.

While EPA previously expressed prior concern about certain aspects of the previous API survey data, API expects that providing these data developed from Subpart OOOOa surveys should adequately address any EPA concerns. The Subpart OOOOa data confirm that semi-annual leak monitoring provide limited incremental environmental benefit and support EPA's proposed annual survey frequency. While the dataset were not produced from a controlled experiment with a collection of well sites undergoing semi-annual monitoring and another set undergoing annual monitoring, the data clearly indicate that moving to an annual frequency will not result in an appreciable increase in emissions. API welcomes the opportunity to discuss these data further with EPA.

Figure 2. Semi-Annual Leak Survey Data Monitored per § 60.5397a Comparing Number of Leaks Found per Survey over Two Years



Attachment C

Production Flows and Operating Pressure

Discussion on Production Flows and Operating Pressures

EPA's discussions in the preamble regarding increased production from refracturing a well (83 Fed Reg. at 52073), leads to the statement that "[T]he increase in production rate requires an increase to either the operating pressure and/or the duration of or frequency of flow events" is incorrect. The cited theory that to increase flow across a given cross-sectional area requires an increase in pressure is certainly true for a static system where the cross-sectional area is fixed. However, production flow through wellheads, process lines, separators and other equipment at a well site is a dynamic system in which pressure control valves adjust the cross-sectional area of their valve ports to moderate flow in order to maintain desired operating pressures. This allows a production unit to operate at the same approximate operating pressure over a wide range of flow rates.

Typically, the operating pressure of the first and/or second separator at a well site, or at a central tank battery with process equipment, is kept at a set pressure with a pressure control valve that allows more or less gas flow to the sales line. However, for production sites only, the most important control valves are "choke valves" on the wellhead.

The following is from EnggCyclopedia[35]:

> *"Choke valve is a type of control valves, mostly used in oil and gas production wells to control the flow of well fluids being produced. Another purpose that the choke valves serve is to kill the pressure from reservoir and to regulate the downstream pressure in the flowlines. Choke valves allow fluid flow through a very small opening, designed to kill the reservoir pressure while regulating the well production. The reservoir fluids can contain sand particles. Hence the choke valves are usually designed to handle an erosive service.*
>
> *Typically oil and gas producing wells have two choke valves in series, one non-regulating choke valve and one regulating choke valve downstream to the non-regulating choke valve.*

Non-regulating choke valves
Function of the non-regulating choke valve is to act as an on-off valve and kill the reservoir pressure to a desired operating value in the flowline. The opening in the choke valve is sized to kill the pressure when valve is fully open. The non-regulating choke valve is not used for flow regulation and hence is not sized for controlling the flow. Over the life of an oil production well, the reservoir pressure drop as fluids are depleted from the reservoirs. Hence with dropping reservoir pressure, the non-regulating valves may have to be changed to maintain the same well production levels. Hence over the life of an oil production well, the non-regulating choke valves can be replaced with valves having increasingly larger openings for flow.

Regulating choke valves
The regulating choke valve is a flow control valve that is designed to maintain a steady production level in the flowlines and production header. Regulating choke valve is an automatic valve and valve opening can be controlled via electric or pneumatic signal from the control panel to regulate the flow in downstream flowlines."

[35] https://www.enggcyclopedia.com/2012/03/choke-valves/

Therefore, in the case of a successful refracturing of a well which restores much of the well's reservoir pressure and results in an increased production rate, a regulating choke valve would adjust to maintain the desired operating pressure and, if needed, a non-regulating choke valve could manually be replaced with a valve having a smaller opening for flow."

Thus, the fugitive components downstream of wellhead valve would not necessarily experience an increase in pressure even though flow increased.

Attachment D

Sample Observation Narrative

The following is one example of a sample narrative to describe a general process a company could use to describe an observation path as discussed in detail in Comment 3.0.

Observation Path at Well Site: The path shall start at the wellhead or inlet header and move along any lines attached containing the possibility of leaking fugitive emissions. This path should encompass any storage and process vessels on the site. The physical path followed by the inspector will differ from site to site due to the construction layout of each well site. The inspector will need to adjust distance from components based on camera lens, wind speed, and any adverse monitoring conditions to identify any fugitive emissions from all applicable components.

Observation Path at Compressor Station: The path shall start at the inlet header and move along any piping containing the possibility of leaking fugitive emissions. This path should encompass any storage and process vessels on the site. The physical path followed by the inspector will differ from site to site due to the construction layout of each compressor station. The inspector will need to adjust distance from components based on camera lens, wind speed, and any adverse monitoring conditions to identify any fugitive emissions from all applicable components.

Deviation from Observation Path: Any deviations from this monitoring path will need to be recorded on the survey sheet. In the event that no deviations from the monitoring path occur, inspector will note there were no deviations from the monitoring path.