Submitted via email.

April 5, 2024

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

Re: Provisions in EPA's Final Rule "New Source Performance Standards and Emission Guidelines for Crude Oil and Natural Gas Facilities: Climate Review" Creating Immediate Compliance and Implementation Issues

Dear Administrator Regan,

The American Petroleum Institute (API) and the American Exploration and Production Council (AXPC) hereby submit this petition for changes to the Final Rule entitled "New Source Performance Standards and Emission Guidelines for Crude Oil and Natural Gas Facilities: Climate Review" (89 FR 16820, March 8, 2024) due to the immediate compliance and implementation issues we describe herein.

API and AXPC jointly submit this petition for convenience and efficiency. API and AXPC each respectively reserves its individual rights in submitting this request.

The American Petroleum Institute (API) is the national trade association representing America's oil and natural gas industry. Our industry supports more than 11 million U.S. jobs and accounts for approximately 8 percent of U.S. Gross Domestic Product (GDP). API's nearly 600 members, from fully integrated oil and natural gas companies to independent companies, comprise all segments of the industry. API's members are producers, refiners, suppliers, retailers, pipeline operators, and marine transporters, as well as service and supply companies, providing much of our nation's energy. API was formed in 1919 as a standards-setting organization and is the global leader in convening subject matter experts across the industry to establish, maintain, and distribute consensus standards for the oil and natural gas industry. API has developed more than 700 standards to enhance operational safety, environmental protection, and sustainability in the industry.

AXPC is a national trade association representing 34 leading independent oil and natural gas exploration and production companies in the United States. AXPC companies are among leaders across the world in the cleanest and safest onshore production of oil and natural gas, while supporting millions of Americans in high-paying jobs and investing a wealth of resources in our communities. Dedicated to safety, science, and technological advancement, our members strive to deliver affordable, reliable energy while positively impacting the economy and the communities in which we live and operate. As part of this mission, AXPC members understand the importance of providing positive environmental and public-welfare outcomes and responsible stewardship of the nation's natural resources. It is important that regulatory policy enables us to support continued progress on both fronts through innovation and collaboration.

This document is organized into three sections. First, we present the issues which entail urgent and insurmountable compliance hurdles due to legal, practical, or technical infeasibility. Immediate changes to those provisions are needed to alleviate the widespread and immediate imposition of impossible compliance obligations. Second, we explain that a targeted stay of those provisions is needed and warranted. Third, we present additional issues which we believe EPA should address in the rulemaking the agency undertakes to accomplish administrative reconsideration and resolution of the issues for which we request a stay.

Thank you for your prompt consideration of this request. We look forward to continuing constructive engagement with EPA to ensure the Final Rule is cost-effective, technically feasible, and accomplishes our shared goal of reducing emissions. Please contact Ryan Steadley (steadleyr@api.org) and Wendy Kirchoff (wendy.kirchoff@axpc.org) if you have any questions.

Sincerely,

Holly Hopkins	Wendy Kirchoff
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Vice President, Upstream Policy	Vice President of Policy and Regulatory Affairs
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CC:
Joe Goffman, EPA
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Provisions Creating Immediate Compliance and Implementation Issues
EPA's Final Rule "Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review"
March 8, 2024
Docket ID: EPA-HQ-OAR-2021-0317

I. PROVISIONS FOR WHICH WE REQUEST A RULE REVISION DUE TO LEGAL, TECHNICAL, OR PRACTICAL INFEASIBILITY.

1. The standards and compliance assurance requirements for flares and enclosed combustion devices are technically infeasible, logistically impossible to meet for the vast number of immediately affected facilities, and unnecessary.

The Final Rule imposes vent gas NHV monitoring and alternate sampling demonstration requirements on flares and enclosed combustion devices. 40 C.F.R. §60.5412b(d) and §60.5417b(d). Those NHV requirements are technically infeasible, logistically impossible to meet industry-wide, and unnecessary for most production sites and compressor stations. These requirements will immediately apply to thousands of affected facilities on the effective date of the rule and, thus, will impose impossible compliance obligations across wide swaths of the industry. Immediate changes to the rule are needed to avoid that outcome.

The NHV monitoring and alternate sampling demonstration requirements are technically infeasible, impracticable, or otherwise impossible to meet for several reasons:

- **Continuous monitoring or one-hour sampling is technically infeasible given the intermittent flow to control devices.** In some cases, flow to the control device may occur for as little as a few minutes making continuous monitoring or collection of a single one-hour sample impossible, let alone 28 one-hour samples as required by the Final Rule. Sampling equipment is also not designed to operate in low temperatures or with all types of gases.

- **Changes in the Final Rule did not alleviate the intractable sampling and monitoring problems.** Among other things, EPA reduced the number of required samples from 240 to 28 but also extended the sampling duration from 10 to 14 days. The reduced number of samples does not make the sampling technically feasible, and the extended sampling duration adds time and costs to an already technically infeasible option.

- **Due to the thousands of control devices immediately subject to NSPS OOOOb NHV requirements[1] and existing supply chain constrains for monitoring equipment or**

[1] The number of control devices subject to NSPS OOOOb requirements during the initial compliance period is higher than EPA's estimate due to a failure to fully consider the consequences of the modification definition. for storage vessel affected facilities. The NHV requirements are still untenable even with just new affected facilities since December 6, 2022.

sampling vendors, compliance is impossible to achieve within the compliance timeline. There are not enough sampling crews to handle the tens of thousands of samples that would have to be taken across the affected industry within just a short period after the effective date of the rule. A single sampling crew can typically visit no more than two or three sites in one day due to the geographically dispersed nature of upstream operations. Moreover, even if the samples could be taken within the prescribed period (which they cannot), there simply is not enough lab capacity to conduct the necessary analyses for each sample.[2] Altogether, full compliance across the industry will be impossible to achieve.

- **Installation of monitoring equipment or sampling ports on existing control devices requires specialized "hot tap" work, which cannot be accomplished across the industry prior to the deadline for compliance demonstrations.** A "hot tap" requires specialized vendors and a site shutdown to perform, which exacerbates the already-impossible compliance timeline given existing supply chain constraints and the large number of needed retrofits.

We note that NHV monitoring is not required in existing state upstream regulations – even for leading states like Colorado and New Mexico. And upstream operators are not currently conducting NHV monitoring for operational or other non-regulatory reasons. Thus, NHV monitoring at upstream flares and combustion emissions control devices has not been demonstrated to be feasible or cost effective and, thus, cannot be considered current BSER.

In addition to being technically infeasible and impracticable, the NHV requirements are unnecessary for virtually all upstream operations as demonstrated by a recent operator survey of NHV data conducted by API and AXPC through a third-party consultant. The data set included over 22,000 data points, 18 operators, and approximately 4,200 sites. The results showed more than 99.5% of the NHV data was at least 800 Btu/scf and more than 99.9% was at least 300 Btu/scf. These results appeared consistent across 5 basins representing 99% of the data. While some sources with multiple data points showed variability, the NHV was still well above 800 Btu/scf for those sources. All NHV data ≤ 900 Btu/scf in the survey were from known scenarios where large amounts of inert gas(es) are expected. Operators know which scenarios or sites have the potential for large amounts of inert gases to reduce the NHV of vent streams below the required minimum; these known scenarios include: (1) sites in fields using water or carbon dioxide (CO_2) flood Enhanced Oil Recovery (EOR); and produced water tanks not collocated with oil tanks in certain dry gas plays.

In sum, NHV monitoring for upstream flares and combustion emissions control devices is technically infeasible, logistically impracticable given the vast number of immediately affected facilities, and unnecessary in all but a handful of upstream operations. As a result, immediate changes to the Final Rule are needed to avoid the imposition of widely applicable and impossible compliance obligations.

[2] See Attachment 1 for the March 19, 2024 letter from SPL, Inc. to EPA documenting the lack of adequate lab capacity.

Along the same lines, we also note that the Final Rule requires that steam- and air-assisted combustion control devices meet a minimum combustion zone net heating value (NHVcz) and a NHV dilution parameter (NHVdil) for devices that use perimeter assist air. 40 C.F.R. §60.5412b(a)(1)(iv)(C) & (D) and §60.5412b(a)(3)(iii) & (iv). The Final Rule also imposes associated continuous monitoring requirements to demonstrate that the control device meets the applicable NHVcz and NHVdil. *Id.* at §60.5417b(d)(8)(vi). These NHVcz and NHVdil requirements mirror those in 40 C.F.R. 63, Subpart CC (Refinery MACT), and the monitoring requirements reference 40 C.F.R. §63.670 of Refinery MACT.

The NHVcz and NHVdil requirements from Refinery MACT are inappropriate and overly burdensome because well sites, central production facilities and compressor stations are fundamentally different than petroleum refineries. Most importantly, the oil and natural gas production sector does not operate at steady state conditions and equipment design must be tailored to the conditions and fluid compositions supplied by the reservoir. Hydrocarbon fluids (including oil, condensate, and produced water) and natural gas are located thousands of feet below the surface and must flow to the surface for separation. Separation occurs in either a two- or three- phase separator with intermittent pulses of produced water sent from the bottom of the separator to its storage vessel, hydrocarbon liquids from the middle to its storage vessel, and natural gas off the top of the separator to the gathering system.

As production declines, management of liquids can mean that flow to the storage vessel can vary from essentially zero to high flow rates and quickly back to zero rapidly and often. The same is true for how vapors from the storage vessel will be expected to flow to a control device since emissions occur from flashing and working losses as liquid periodically flows into the storage vessel from the separator. This highly variable, non-steady state flow mandates equipment to be sized much larger than ideal steady state conditions would dictate and makes flow measurement infeasible in these conditions.

Applying refinery-oriented requirements to upstream flares is not appropriate nor cost effective. Costs for Refinery MACT controls and monitoring equipment at refineries are $1 million or more, with major ongoing costs. These costs will be much greater at upstream facilities without the necessary utilities and instrumentation resources available for a large complex facility such as a refinery. It is also unclear whether instrumentation is available that would work reliably under these varying operating conditions.

While the Final Rule includes provisions for alternate test methods and alternate NHVcz and NHVdil demonstrations in lieu of monitoring, those alternatives may not be feasible for every control device. In any event, alternate test methods are costly to implement and take time for agency approval, so they are not an option for immediate compliance and unlikely to be used by small operators. Moreover, the alternate NHVcz and NHVdil demonstrations are problematic given that production sites do not operate under steady state conditions.

In short, the standards and monitoring requirements for steam- and air-assisted combustion control devices in the Final Rule must be revised to reflect the fundamental differences between refineries and production facilities and compressor stations.

Because the provisions regarding NHVcz and NHVdil for steam- and air-assisted flares were not part of the November 2021 Proposal[3] or December 2022 Supplemental Proposal,[4] we were unable to formulate comments on these important issues during the public comment periods. Had we been provided the opportunity, we would have submitted comments comparable to those outlined above. These issues are of central relevance to the outcome of the rule because the standards and compliance assurance provisions for the NHVcz and NHVdil provisions are a fundamental part of the overall regulatory scheme for flares. Consequently, pursuant to CAA § 307(d)(7)(B), we request administrative reconsideration of the standards and compliance assurance provisions for steam- and air-assisted flares.

2. The "no identifiable emissions" standard applicable to covers and closed vent systems is unfounded and impossible to meet.

The Final Rule requires that covers and closed vent systems must be designed and operated with "no identifiable emissions." 40 C.F.R. § 60.5411b(a)(3). In other words, the rule imposes a zero-emissions standard. The compliance procedures for that requirement specify that fugitive monitoring methods must be used (including OGI, Method 21, and/or AVO) and impose repair requirements that are largely indistinguishable from the similar requirements that apply under the equipment leak standard. *Id*. at § 60.5416b. But as finalized, a violation occurs any time emissions are detected – even if timely and effective corrective action is taken.

In our comments on the proposed rule, we explained that a "no identifiable emissions" standard is not warranted or justified for fugitive leaks from covers and closed vent systems. We explained that, as a legal matter, covers and closed vent systems must be regulated using work practices because leaks from such equipment "cannot be emitted through a conveyance designed and constructed to emit or capture such" leaks. CAA § 111(h)(2). As a practical matter, we explained that fugitive leaks from covers and closed vent systems are no different than the fugitive leaks covered by the equipment leak provisions and that EPA long ago rejected the idea that numeric emissions limitations can or should be applied to fugitive emissions components.

More importantly, we also explained that a "no identifiable emissions" standard would be impossible to meet in practice because leaks inevitably occur due to normal wear and tear of affected equipment (e.g., a rusty bolt causing a flange leak) and often occur through events that are not reasonably within the control of the operator. At the same time, we recognized that certain leaks can appropriately be attributed to the operator (e.g., forgetting to close a thief hatch) and suggested that the rule should clearly differentiate such leaks from leaks that are truly fugitive in nature.

For these reasons, we request that EPA revise the "no identifiable emissions" standard for covers and closed vent systems such that routine fugitive emissions from such systems do not constitute a violation of the rule, provided appropriate corrective action is taken (consistent with the standards for fugitive equipment leaks).

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[3] 86 FR 63110-63263

[4] 87 FR 74702-74847

3. The performance testing provisions for enclosed combustion devices must be clarified as they are currently untenable.

Confusion exists among delegated authorities and source test vendors about allowable methods for enclosed combustion device (ECD) performance testing. EPA should convene or otherwise engage with delegated authorities, source test vendors, and the industry to discuss and provide clarification on allowed ECD test methods. Furthermore, due to the testing duration, allowed test methods, hundreds of ECDs that require testing under NSPS OOOOb, additional time is needed to conduct performance testing for ECDs at affected facilities constructed, modified, or reconstructed since December 6, 2022.

Although EPA has offered that delegated authorities may approve shorter sampling durations or representative conditions for performance testing, the industry's experience has been that delegated authorities have been hesitant to do so. This is particularly true due to the technical infeasibility of the approved methodology necessitating alternate testing conditions be the norm rather than the exception. Further, relying on delegated authorities to address performance testing issues provides no solution on Tribal lands over which EPA will be the sole agency implementing NSPS OOOOb. This approach inherently disadvantages operations located on Tribal lands. While EG OOOOc control devices have years to address these challenges, they present an immediate and untenable scenario for NSPS OOOOb control devices. Recent operator experience in Colorado has demonstrated the challenges in conducting performance tests on ECDs. These challenges include:

- The amount of time required and the need for supplemental gas to conduct 3 one-hour test runs on sources that have intermittent flow (e.g., storage vessels). A testing crew is typically able to conduct up to 2 performance tests per day where vapor flow is sufficient. Where vapor flow is low and/or intermittent, as can be the case for many storage vessels, it may take multiple days of waiting to find a window with sufficient flow to accommodate a one-hour test run, and in many cases, there will never be sufficient vapor flow to accommodate a one-hour test run under normal operating conditions.
- The lack of sample ports on existing ECDs requires either "hot tap" to install the ports or the use of a shepherd's hook or similar device to conduct performance testing.
- The need to conduct outlet-only testing using Other Test Method 52 (OTM-52): Method for Determination of Combustion Efficiency from Enclosed Combustion Devices Located at Oil and Gas Facilities rather than the test methods listed in NSPS OOOOb. 40 C.F.R. §60.5413b.

Specifically, as stated in previous comments on NSPS OOOO and OOOOa, use of EPA Method 2, 2A, 2C, or 2D is not technically feasible as required by the Final Rule. 40 C.F.R. §60.5413b(b)(2). EPA has not adequately shown resolution of the technical challenge of directly measuring the volume of material resulting from the flash of materials in storage vessels that occurs only when the separator dumps condensate to the storage vessel.

The impact to environmental emissions controls is that flow to the control device varies from essentially zero to high flow rates and quickly back to zero rapidly and often. This highly variable, non-steady state flow mandates equipment to be sized larger than ideal steady state conditions would dictate and makes flow measurement infeasible, particularly to meet the requirement to accurately measure such volume within ±2 percent. Industry has found no such flow meter available that can handle the variable flow which occurs with many of our combustion devices.

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

Aside from the technical challenges of obtaining an accurate flow reading for a performance test, there are safety risks for testing personnel due to the need to access the flow line feeding the control device while equipment is operational and flow to device is occurring. To adequately mitigate these risks, a facility shutdown, potentially including the shut-in of numerous wells would need to occur.

While manufacturer-tested ECDs solved some of the technical challenges with performance testing, even these manufacturer-tested devices are now subject to periodic performance testing under NSPS OOOOb. EPA had previously acknowledged the challenges in conducting ECD performance testing in the field and had required continuous control device monitoring rather than periodic performance testing for manufacturer-tested devices. Another complication is that NSPS OOOO/OOOOa certified ECDs may not be able to be certified as NSPS OOOOb control devices based on the previous manufacturer performance tests due to differences in the testing requirements. In this case, the operator would then be required to conduct an initial performance test if the NSPS OOOO or OOOOa affected facility is modified and becomes subject to NSPS OOOOb, which is a likely scenario for storage vessels (see Comment 4 below).

4. The storage vessel modification provision is overbroad, and the applicability determination requirements are ambiguous for pre-effective date storage vessels. As a result, a vast number of storage vessels have been "modified" since the proposal and must comply with the rule upon the effective date, and operators need additional time to evaluate applicability and implement compliance measures.

The Final Rule includes a modification definition that is specific to storage vessels ("tanks"). Section 60.5365b(e)(3)(ii) identifies four events that constitute a modification. The first two – adding a new tank to an existing tank battery and increasing the cumulative storage capacity of an existing tank battery when replacing one or more tanks – are not controversial. The second two, however, encompass a wide range of events and activities that are part of routine operations and, as such, do not constitute "modifications" under CAA § 111 or EPA's Part 60 regulations.

Section 60.5365(e)(3)(ii)(C) provides that a tank or tank battery at a well site or centralized production facility is modified when it "receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput from actions, including but not limited to, the addition of operations or a production well, or changes to operations or a production well (including hydraulic fracturing or refracturing of the well)." Section 60.5365(e)(3)(ii)(D) provides that a tank or tank battery not located at a well site or centralized production facility is modified when it "receives additional fluids which cumulatively exceed the throughput used in the most recent (i.e., prior to an action in paragraphs (e)(3)(ii)(A), (B) or (D) of this section) determination of the potential for VOC or methane emissions."

Both provisions are based on the presumption that each specified event necessarily constitutes a physical change or change in the method of operation of an associated tank or tank battery and necessarily will cause an emissions increase at the tank or tank battery, thus automatically resulting in a "modification" of the tank or tank battery. We explained in our comments on the proposed rule that such a presumption is invalid.

We explained that the specified events clearly do not constitute a physical change to an associated tank or tank battery. Moreover, such events cannot necessarily be seen as a change in the method of operation of an associated tank or tank battery because tanks and tank batteries in this sector typically are designed and operated to accommodate a wide range of conditions to reflect the widely varying and constantly changing operations that they serve. Moreover, changes in throughput do not necessarily cause an emissions increase under EPA's long-established principles for determining emissions increases under CAA § 111. For these reasons, we respectfully request that EPA revise the storage vessel modification provisions to prevent their application to events and activities that are not modifications.

Furthermore, for tanks that commenced construction, modification, or reconstruction prior to the OOOOb effective date ("pre-effective date tanks"), May 7, 2024, the applicability determination language in 40 C.F.R. § 60.5365b(e)(2)(ii) is ambiguous. Specifically, it is unclear what "30-day period of production" operators must use to determine the maximum average daily throughput to calculate the potential for VOC and methane emissions for pre-effective date tanks. Without clarification, operators cannot know with certainty the scope of affected storage vessels that must comply with NSPS OOOOb by the imminent compliance deadline. Accordingly, API and AXPC request that EPA stay the NSPS OOOOb storage vessel compliance deadline for pre-effective date tanks to allow sufficient time for EPA to develop guidance on this issue and for operators to evaluate applicability and begin compliance implementation based on EPA's guidance. This reasonable request would avoid potentially unnecessary and significant compliance costs where compliance is not required in the first instance.

II. AN IMMEDIATE STAY IS NEEDED AND WARRANTED

We understand that it will take time to devise and implement appropriate changes to the final rule for the four provisions discussed above. But starting on the effective date of the rule – about 30 days from the date of this letter on May 7, 2024 – virtually no affected facility will be able to comply with any of those provisions. In particular:

- The NHV standards and monitoring requirements for flares and enclosed combustion devices are not practicable or necessary given the fundamental differences between combustion control devices in the upstream sector and refinery flares (for which the NHV requirements were designed) and, in any event, supply constraints will prevent most affected facilities from obtaining the needed monitoring equipment.
- Affected facilities will not be able to prevent inevitable minor fugitive emissions from covers and closed vent systems.

- The expansive storage vessel modification provisions will immediately and automatically trigger new source requirements for tens of thousands of tanks and tank batteries (far more than EPA predicted when formulating those provisions), which will expose vast swaths of the industry to the problems described above.

We therefore request that EPA defer the effective date of these provisions for the period needed to implement appropriate revisions. Deferral of the effective date is within EPA's authority and would be an expedient way to afford relief until the rule can be appropriately revised.

The Clean Air Act does not specify the date that a rule must be made effective. EPA thus has discretion to reasonably determine an effective date according to the circumstances presented by each rule. Here, given the widespread inability to achieve compliance by May 7, EPA has ample justification to defer the effective date of these five provisions until after appropriate revisions to the rule are accomplished.

We further note that, under these circumstances, EPA should issue an immediately effective change to the effective date of these provisions under Administrative Procedure Act § 553(b), which authorizes EPA to issue a final rule without prior notice and an opportunity for comments when it "for good cause finds (and incorporate the finding and a brief statement of reasons therefore in the rules issued) that notice and public procedure thereon are impracticable, unnecessary, or contrary to the public interest."

Invoking the "good cause" provision is warranted here because providing notice and an opportunity for public comment would be: (1) impracticable given that the rule becomes effective in less than 30 days; (2) unnecessary because public comments would not change the fact that immediate relief is needed from impossible regulatory obligations; and (3) consistent with the overarching public interest in promulgating rules that can reasonably be implemented within the timeframes allowed. Also, a limited and targeted deferral would not significantly diminish the overall emissions reductions accomplished by the rule and the corresponding benefits to health and the environment.

We note that in recent similar situations, EPA has asked for public comments on a "good cause" final rule, which allows the Agency to quickly finalize needed rule changes, while at the same time positioning the Agency to do a mid-course correction if comments reveal facts or consideration that were not available to the Agency at the time the immediately effective final rule was issued.

For example, EPA followed this approach in issuing technical corrections to the recently amended NSPS for electric arc furnaces. 89 Fed. Reg. 11198 (Feb. 14, 2024). EPA invoked the APA "good cause" provision, but characterized that action as an "interim final rule." *Id*. EPA explained that it found "good cause to take this interim final action without prior notice or opportunity for public comment" but also decided to provide "an opportunity for comment on the content of the amendments and, thus, request[ed] comment on the corrections described in this rule. " *Id*. at 11203.

EPA should take a similar approach here.

Alternatively, EPA has authority under APA § 705 to stay the effectiveness of a rule pending resolution of litigation. Challenges to the Final Rule were filed by the State of Texas and others on the date the rule was published. So, APA § 705 is available to EPA. A stay pursuant to APA § 705 is justified because: (1) any judicial challenge to the five key provisions is likely to succeed, for the reasons explained above; (2) the rule will cause irreparable harm by imposing an impossible regulatory obligation; (3) EPA would not be prejudiced by pausing targeted and narrow parts of the rule for the period needed to revise them; and (4) public policy considerations support deferral of unlawful and impossible regulatory obligations.

III. ADDITIONAL ISSUES

5. EPA should extend the temporary flaring provisions for certain situations.

We support EPA's general approach finalized §60.5377b(d) that allows temporary flaring of associated gas for unique situations, including the following:

- During a malfunction or incident that endangers the safety of operator personnel or the public you are allowed to route to a flare or control device for 24 hours or less per incident.
- During repair, maintenance including blow downs, a production test, or commissioning, you are allowed to route to a flare or control device for 24 hours or less per incident.

However, as EPA is aware, there are certain oil and natural gas production operations that are remote and spread out over many miles. Some of these operations are located in areas that are prone to severe winter weather events that could prevent operators from accessing these remote sites for longer than 24 hours. For example, seasonal weather in North Dakota may cause local agencies to close roads due to seasonal weather whereby people and equipment would be prevented from arriving at a location within 24 hours. Therefore, we ask EPA to extend the temporary flaring provisions for malfunction and/or repair or maintenance activity to 72 hours from 24 hours as finalized. We note these specific timing restrictions were not in the proposal and therefore we did not have the opportunity to comment on the timelines finalized. We also note that the final preamble states[5] that EPA intended to allow 72 hours for temporary flaring, "...during repair, maintenance including blowdowns, a packer leakage test, a production test, or commissioning."

6. EPA should clarify that the rule inadvertently failed to provide guidance for temporary equipment.

a. Well Liquids Unloading

Well liquids unloading involves a wide range of activities and we support the work practice procedures generally finalized §60.5376b. However, the requirements finalized in §60.5376b(g) include reference to the covers, closed vent and control device requirements, which include significant compliance assurance requirements. These references were not contemplated or

[5] 89 FR 16820-16949

referenced in either of EPA's previous proposals as it related to well liquids unloading events, so we have not had an opportunity to provide previous comment.

When implementing the work practice procedures to reduce emissions from well liquid unloading activities as specified in §60.5376b(b)-(f), operators will review the characteristics of the well at the time of the event. If certain conditions are present, an operator may need to deviate from a planned option for minimizing emissions and instead route gas to a temporary flare to minimize emissions and further reduce the amount of gas that would be vented by 95%.

Given the short-term nature of liquids unloading events, the ongoing compliance assurance related to both a closed vent system and control device would be inappropriate since many of the activities would be forced to occur when liquids unloading activities are not even occurring. Examples of this include the proposed NHV monitoring or alternate demonstration provisions and/or the periodic CVS inspections. It would also be untenable to schedule and manage these activities during unloading events given their variable and short duration.

We believe the use of a temporary flare or portable control device should be authorized to handle emissions from liquids unloading. Due to the temporary nature of these activities, the control device compliance requirements should mimic the requirements of control devices utilized for well completions affected facilities, i.e., operated with a reliable continuous pilot flame during the liquid unloading activity.

b. Process Controllers (Pneumatics)

In our February 13, 2023 comment letter, API provided explicit examples for why pneumatic controllers associated with temporary equipment should be exempt from the zero-emissions standard, which EPA failed to adequately clarify in the final rule.

These new provisions for zero emitting process controllers completely alter how the oil and natural gas industry powers and controls equipment and extensive capital planning and investment is required to meet the zero-emitting standards. For certain temporary activities, where equipment is owned and leased by a third-party supplier, the third-party equipment would not be able to "plug-in" to the site's permanent design.

Specifically, EPA should exclude any natural gas-driven process controllers on equipment that is skid mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships) and intended to be located at a site for less than 180 consecutive days. This approach is consistent with language describing applicability of temporary storage vessels under NSPS OOOO, NSPS OOOOa, proposed NSPS OOOOb, and proposed EG OOOOc. Two such examples include:

1. Operators may utilize a small injection compressor to assist in ramping up production for new wells that have recently ended flowback. These compressors are typically skid mounted and located on site for as few as 30 days after the startup of production. These compressors contain a handful of pneumatic controllers to assist in proper function on the unit and may sometimes be leased from a third-party service provider.
2. Another example is the use of a temporary compressor at a wellsite that is needed in anticipating gathering system high line pressure during new gathering system infrastructure

build-out, which may occur for a few months. This equipment can also be provided by a third-party service provider and are not owned by the main operator (e.g. capital planning and equipment upgrades are the responsibility of the third-party)

Additionally, it is common for EPA to identify provisions that begin at the startup of production. We ask that EPA clarify their intent for the process controller provisions as well. As EPA is aware, drilling and completion activities require specialized temporary use equipment that is often contracted by third-party suppliers. While not overly common, some of the drilling or flowback equipment brought onsite might contain pneumatic controllers or pumps. Even for new sites planning to comply with the zero emitting provisions using electricity or instrument air, that infrastructure would not be present at the facility for use during construction phase support activities. Any process controllers or pumps associated with drilling and completion equipment should be excluded from the zero-emitting process controller requirements, which can be accomplished by clarifying that the requirements for process controllers are not applicable until after the startup of production like other provisions within the proposed standards.

ATTACHMENT 1

March 19, 2024 Letter from SPL, Inc. to EPA

24 Waterway Ave, Suite 375
The Woodlands, TX 77380
(720)-683-8633

To: Michael S. Regan
EPA Administrator
1200 Pennsylvania Ave, N.W.
Washington, DC 20460

Date: March 19th, 2024

Mr. Regan,

On behalf of SPL, Inc and our many customers in the oil and gas industry, I submit this letter to you regarding the recently published 40 CFR Part 60 "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for existing Sources: Oil and Natural Gas Sector Climate Review". I write to provide specific commentary regarding the 60-day compliance mandate § 60.5370b for control devices § 60.5417b(d).

SPL is the largest laboratory in the United States specializing in the analysis of hydrocarbon products, processing more than 225,000 natural gas samples each year. In recent months, we have received countless inquiries from our customers seeking guidance on how to determine the net heating value of their vent gases. Speaking from our direct experience analyzing 1,000s of vent gas samples from every major oil and gas producing region of the United States annually, it would be exceptionally uncommon for the heating value of vent gas to fall below the threshold the EPA has set. Should the EPA not reconsider this requirement, we at SPL believe compliance with the rule as written is possible, but not within the timeframe required to comply. Below, we submit several concerns that the EPA should consider before enforcing any mandate on the oil and gas companies related to this requirement.

- Vent gases are exceptionally heavy gases (relative to air) that are typically depleted with respect to lighter hydrocarbon molecules such as methane and ethane, and enriched in molecules like propane, butane and pentane. As a result, these heavy gases have a lower vapor pressure (relative to a methane-enriched sales gas for example) and therefore don't "flash" from the liquid hydrocarbon stream until the final stage of separation. Whereas the net heating value of methane is 909.4 Btu/ft^3, the net heating value of propane, n-butane and n-pentane is 2,315 Btu/ft^3, 3,000 Btu/ft^3 and 3,707 Btu/ft^3 respectively (source: GPA 2145). Therefore, unless there is a source of inert gas diluting the vent gas stream (sources of inert gas could be added by design, or, due to leaking equipment), there should be no compositional reason the net heating value of that gas would be under the threshold set by the EPA. Speaking directly to SPL's experience, any vent gas sample falling below the EPA's threshold would have been significantly diluted by an inert gas.

- The amount of additional natural gas samples this requirement will result in is vastly greater than the capacity that laboratories have to collect and process such samples in the 60-day window. For example, a producer with 70 devices subject to net heating value determination would mean that they will produce 1960 samples in a 14-day period (assuming each location has both a high- and low-pressure flare). This testing increase from one customer alone, when considered with the volumes generated in the 60-day period nationally, would far exceed the analytical capacities of US laboratories performing the analysis. For SPL specifically, 1960 samples in 14 days would exceed the monthly throughput of most of our regional laboratories. There are not enough gas chromatographs, sample cylinders, and human resources to make compliance within 60-days a possibility.

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- The EPA is requiring "the minimum time of collection for each individual sample be at least one hour". This requirement goes against the traditional norms for the collection of natural gas samples and therefore will require all sampling entities to deploy alternative strategies that are not widely available at the moment. Proper sample collection techniques are paramount to ensure a representative sample is analyzed by the laboratory. Typical methods for the collection of natural gas samples call for spot sampling techniques that procure gas on very short (seconds to minutes) timescales. The one-hour requirement set forth in the regulation will require the composite sampling techniques typically used in custody-transfer applications (and elsewhere) to be adapted to a more rugged and transportable set up to meet compliance. Again, this requirement can be achieved, but not within the current scope of 60 days. Alternatively, sample collection methods such as those referenced in GPA 2166-22 should be considered permissible by the EPA to eliminate this bottleneck all together.

- The description of the sample canister provided in the regulation suggests the EPA will require Summa Canisters for vent gas collection. Summa canisters present several logistical hurdles that make compliance with § 60.5417b(d) difficult because they are expensive, large, and are not designed for applications such this. Summa cannisters were designed primarily for atmospheric gas sampling. In order to collect 1-hour samples by summa cannister, restrictive flow metering devices will be required. These devices primarily rely on restrictive orifice to meter the gas into the summa cannister. The potentially wet and dirty nature of flare gas will rapidly foul these devices resulting in errors in collection and potential contamination bias. Instead, for operators and laboratories to meet sample demand in a reasonable manner, single cavity stainless steel constant volume cylinders should be allowed for sample collection so long as they are maintained according to the requirements set forth in 43 CFR 3175 (Onshore Oil and Gas Operations; Federal and Indian Oil and Gas Leases; Measurement of Gas).

- The analytical method for the compositional analysis of vent gas samples, ASTM D1945, from which net heating value is then calculated, is not widely available. The industry standard for determination of heating value is GPA 2261, however, we understand that certain components of the natural gas the EPA desires, including helium, oxygen and hydrogen, are not standard components of GPA 2261 analyses. Therefore, laboratories across the US will require additional time for method development of ASTM D1945 to have the capacity readily available to our customers. Part of this method development may require additional equipment and/or modification for existing equipment that cannot be achieved in the 60-day timeframe.

SPL supports the efforts of the administration to curb GHG as it is a common goal shared with the oil and gas industry. However, we urge the EPA to extend the time for compliance past the current 60-day period and to alter the sampling techniques to the more applicable industry standards set forth by GPA Midstream and the American Petroleum Institute.

Sincerely,

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