MARCELLUS
SHALE COALITION®

January 31, 2022

U.S. Environmental Protection Agency
EPA Docket Center
Docket ID No. EPA–HQ–OAR–2021–0317
Mail Code 28221T, 1200
Pennsylvania Avenue NW
Washington, DC 20460

Re: **Docket ID No. EPA–HQ–OAR–2021–0317** Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review. *Via Email (a-and-r-docket@epa.gov) and www.regulations.gov*

The Marcellus Shale Coalition (MSC), a regional trade association with a national membership, appreciates the opportunity to submit comments regarding the above-referenced proposed rulemaking. The MSC was formed in 2008 and is currently comprised of approximately 110 producing, midstream, transmission and supply chain members who are fully committed to working with local, county, state and federal government officials and regulators to facilitate the development of the natural gas resources in the Marcellus, Utica and related geological formations. Our members represent many of the largest and most active companies in natural gas production, gathering, processing and transmission, in the country, as well as the suppliers, contractors and professional service firms who work with the industry.

The MSC appreciates the opportunity to offer the following comments on the above-captioned proposed rule relating to Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review (proposed rule, which includes 40 CFR 60 Subparts OOOOb and OOOOc). The member companies of the MSC are proud of their cumulative efforts to date to strengthen domestic energy production, to do so in a manner that protects and enhances our shared environment, and which has led to a precipitous drop in criteria pollutant emissions that has significantly enhanced air quality in Pennsylvania.

Introduction

The MSC offers its support for the public comments submitted by the American Petroleum Institute, the Interstate Natural Gas Association of America, the GPA Midstream Association and the American Exploration and Production Council.

Before providing specific comments to the proposed rule, the MSC offers the following information for consideration to both better illustrate the current regulatory climate here in Pennsylvania as well as the environmental progress already achieved to date.

The Final Rule Should Recognize the Critical Role of Oil & Gas in Meeting the Nation's Energy & Environmental Needs

Any final rules must have a reasonable and cost-effective pathway to compliance. We note for the record that several representatives and nominees of the federal Administration have expressed a public desire to eliminate the use of fossil fuels, including by bankrupting American companies that invest in and produce these energy resources. Such punitive goals and motivations are contrary not only to sound public policy, but also the authority various governing statutes vest within the U.S. Environmental Protection Agency (U.S. EPA or Agency) and other executive agencies. Any motivation for a federal rulemaking that is driven by anything other than protecting the environment through reasonable, affordable and cost-effective measures is cause for concern, and we urge the Agency to resist such efforts.

Pennsylvania's shale operators are focused on producing natural gas and natural gas liquids. The importance of these critical resources could not be more apparent right now – both domestically and abroad, as countries seek adequate and affordable energy resources to meet the winter needs of their citizens while more broadly seeking to emerge from the grasp of a global pandemic. American natural gas and liquids are critical to both missions: providing affordable, clean energy to heat and power American homes, schools, businesses, and other facilities while fueling American manufacturers, including pharmaceuticals, as evidenced by the role natural gas liquids are playing in the health care arena, from PPE to medical equipment to vaccine development and deployment.

U.S. EPA ought to recognize this critical national interest. It is frankly troubling and disconcerting to hear high ranking Administration officials accuse American oil and gas companies of collusion and price gouging, without any evidence, while simultaneously pleading with OPEC[1] – a cartel designed to prohibit market competition and comprised of several terror sponsor states – to increase production and exports to meet the energy needs of our own citizens. This is particularly troubling given that these countries do not subscribe to virtually any environmental standards or commitment to competitive markets. These ill-informed and misguided comments understandably give serious pause to the intended end-goals of federal rules targeted at domestic oil and natural gas production.

Recognize and Account for States with Existing Regulatory Requirements

Since 2005, Pennsylvania has risen to the second largest natural gas producer in the nation, accounting for 20% of our country's natural gas production[2]. Yet since this time, increased use of natural gas for power generation has provided significant environmental benefits for the citizens of Pennsylvania and throughout the region. These benefits[3] of enhanced air quality include:

- A decline in volatile organic compound emissions (VOC) of 40%;

[1] The Organization of the Petroleum Exporting Countries

[2] In 2021, Pennsylvania produced approximately 7.6 trillion cubic feet of natural gas

[3] PA Department of Environmental Protection – Air Emission Report (Power BI)

- A decline in SO2 and NOx emissions of 93% and 81%, respectively;

- A decline of carbon dioxide of 41%, far surpassing the goals laid out in the Paris Climate Agreement.

Comprehensive and robust regulatory programs and new requirements have been adopted since the onset of significant unconventional natural gas development in Pennsylvania. New and existing sources are covered by performance measures to identify and limit leaks, with well pads and midstream infrastructure operating under new and revised air quality general permits. Pennsylvania has compiled an inventory of emissions since 2012 and expanded the scope of participating facilities over the years.

It is also important for the U.S. EPA to recognize that natural gas development in the United States, and particularly in the Appalachian Basin, has some of the lowest methane intensity rates in the world. For example, the International Energy Agency recognizes that the U.S. methane intensity of 8 tons (per thousand tons of oil equivalent) is one of the lowest of major oil and natural gas producing countries in the world, lower than China (9), Russia (13), Venezuela (48) and Libya (103). Here in the United States, the Appalachian Basin's methane intensity is the lowest of the nine major hydrocarbon producing basins in the entire country.[4]

Natural gas operators are rightfully proud of their contribution to reducing climate change inducing emissions. Operators have demonstrated this commitment through their voluntary participation in meaningful initiatives such as One Future, API's The Environmental Partnership, the U.S. EPA's Methane Challenge and the Global Methane Initiative, to name a few. Over 85% of MSC Board members participate in one or more of these initiatives.

Conclusion

The MSC and its member companies take great pride in their efforts to conduct operations safely, efficiently, and in a manner that protects our shared environment and local communities, while at the same time meeting the critical energy needs of our citizens. We welcome the opportunity to discuss in greater detail any questions or need for clarification that you may have regarding our comments.

Sincerely,

David E. Callahan
President

[4] Clean Air Task Force & Ceres: Benchmarking Methane & Other GHG Emissions (June 2021)

SPECIFIC COMMENTS

The MSC offers the following specific comments for consideration:

Effective Date of Subparts OOOOb and OOOOc Proposed Rulemaking

1. The MSC requests that the effective date for the proposed regulation should not be established until the actual draft regulatory text is proposed and published for public review. The proposed rule provides varying degrees of detail describing what U.S. EPA plans to propose in a supplemental regulatory action. Not only does this make commenting on the regulation extremely difficult, but it also places an effective date on new construction and modifications which are in various stages of implementation, such as having a completed design or being ready to commence construction imminently. Many of these projects will have to wait for this supplemental proposal to determine if they include an affected source and subsequent applicable NSPS requirements. Regulatory language for these determinations will not be available for at least several months, possibly after implementation.
2. U.S. EPA should also confirm they will allow comment on the supplemental regulation, which will include regulatory language and that the supplemental regulatory action meets the requirements of the Administrative Procedures Act.
3. In addition, the MSC encourages U.S. EPA to give serious review and consideration of the comments submitted by the West Virginia Department of Environmental Protection as they raise legitimate concerns and questions regarding the role of state environmental agencies and associated burden in implementing the proposed rule.

ABANDONED WELLS

1. The MSC does not view abandoned wells as meeting the definition of an affected source for a new source performance standard. In addition, existing wells will vary in construction and methods for appropriate mitigation and MSC believes this is an issue best addressed at a state level.

PIGGING OPERATIONS AND RELATED BLOWDOWN ACTIVITIES

1. The GPA Midstream Association has developed comprehensive comments for consideration under this section. The MSC offers its support and endorsement of these specific comments.

TANK TRUCK LOADING

1. If truck loading is required to be controlled under Subpart OOOOb, the MSC recommends a threshold requirement for control such as 200 tons per year (tpy) methane,

as currently incorporated in Pennsylvania's General Air Quality Permits for Oil and Gas. These general permits also recognized safety concerns with controlling truck loading with vapor balancing and allow a general control option of 95%.

2. The ability to control existing truck loading under Subpart OOOOc increases the difficulty of collecting and controlling emissions safely. Therefore, the MSC recommends no control requirements under Subpart OOOOc.

3. The GPA Midstream Association has developed additional comprehensive comments for consideration under this section. The MSC offers its support and endorsement of these specific comments.

CONTROL DEVICES

1. The MSC supports retaining the 95% control level for Subpart OOOOb.

2. Verification of control efficiency should include the option to demonstrate efficiency through utilization of manufacturers' guarantees in conjunction with process parameters and engineering calculations and modeling. Many states, including Pennsylvania, require the preparation, submittal and approval of testing protocols, and approval of testing results by the regulating agency. This has resulted in significant burden to these agencies. Additional testing requirements will only exacerbate this situation.

FUGITIVE EMISSIONS

General Overview

The proposed Appendix K requirements for (optical gas imaging (OGI) surveys are overly onerous and would drastically increase the time and cost of conducting required surveys without a significant reduction in fugitive emissions. Additionally, the training and quality assurance requirements in the proposed appendix would result in an immediate shortage of qualified camera operators being available to conduct the required surveys. We have successfully implemented OGI monitoring programs in the Marcellus region that efficiently identify and repair leaks without adding unnecessary burdens that will increase effort and cost.

The majority of affected compressor stations in our region currently observe leaking components in the low single digits per survey while monitoring thousands of components present at each facility. According to the CSU OGI Efficacy Study, there is a 60% increase in detection of leaks with more experienced operators and that higher rate leaks are more likely to be detected by operators with any level of experience. Given the typical number of leaking components detected during a survey as noted above, increased surveys would result in very few additional leaks being detected despite the onerous additional requirements detailed in the proposed Appendix K. The study also notes a 90% probability of detection as a threshold as opposed to 100% detection.

Please see Attachment 2 for detailed comments on Appendix K by section.

1. MSC members have significant experience with OGI monitoring of fugitive emissions at both wellpads and facilities. OGI has been found to be an effective tool for the oil and gas industry utilizing current manufacturers' training and guidance. The proposed changes on the use of OGI cameras for monitoring will reduce the effectiveness of this tool. MSC has provided detailed comments regarding these changes in response to the proposed Appendix K.

2. Control devices and malfunctioning controllers with potential excess emissions should not be classified as leaking components, requiring a root cause analysis and repair "as soon as practicable." Determining if a control device or controller is operating properly requires knowledge of the emissions source and the operation of the control device. Most OGI camera operators would not be acquainted with this information. Furthermore, the permitting of point sources and control devices include means or metrics to determine compliance and proper operation.

<u>STORAGE VESSELS</u>

1. The current Subpart OOOOa regulations require potential VOC emissions to be calculated using a generally accepted model or calculation methodology. MSC requests that U.S. EPA confirm that potential methane emissions shall also be calculated using a generally accepted model or calculation methodology.

2. The proposed revision addresses modifications for changes; however, there is no corresponding provision for an uncontrolled methane emission to the 4 tpy VOC emission rate without control for affected facilities. MSC recommends including an actual methane emission rate below which control may be removed similar to 40 CFR 60.5395a(a)(3).

3. Legally and Practically Enforceable Limits
   - The terms "legally and practically enforceable" are currently defined and codified by U.S. EPA. They are used in synthetic minor determinations under the Title V Operating Permit Program and in the Prevention of Significant Deterioration and Nonattainment New Source Review Programs. These definitions should remain consistent with existing regulations. The additional prescriptive requirements in the proposed definition would require permitting authorities to re-write existing permit conditions to exactly match the language in the proposed rule.

   - The proposed definition states only those <u>limits</u> that include the elements described above will be considered "legally and practicably enforceable" for purposes of determining the potential for VOC emissions from a single storage vessel or tank battery, and thus applicability (or non-applicability) of each single storage vessel or tank battery as an affected facility under the rule. Further clarification is needed to distinguish that other factors, including the maximum capacity under the physical and operational design, need to be considered for determining potential emissions. State regulations that include rolling 12-month emission limits (without a specific throughput limitation) should be considered legally and practically enforceable.

PNEUMATIC CONTROLLERS

1. MSC requests that U.S. EPA retain an exemption for functional and safety needs. This is key for some safety-related systems, especially in the transmission and storage segment, where high pressure gas available within the natural gas pipeline provides the motive source to operate valves that are used to isolate portions of system in response to operational needs, including safety related issues for events such as emergency shutdown. This important category includes intermittent devices, which are primarily used as failsafe system.

2. For new sources regulated under Subpart OOOOb, locations not at well pads or compressor stations (such as interconnections), access to grid power (and zero bleed devices) should be limited to commercially available onsite connections with sufficient and reliable power, which is a subset of sources. These locations in general have a limited number of pneumatics (less than the number in the small model plants). A cost analysis has not been performed for these sites. If such an analysis is not included in an updated proposal, these locations should be exempt from the design requirements.

3. The cost analysis in the proposal is based on the replacement of all pneumatic controllers with zero-emitting devices at model plants. However, the affected facility is defined as each natural gas driven controller. This definition is inconsistent with the cost analysis. MSC recommends either a revised cost analysis (for a single controller) or revised definition of the affected facility (including a threshold above which the standards would be applicable). Related comments include:
   - The MSC requests clarification on modifications regarding pneumatics under Subpart OOOOb. If an operator installs or replaces an existing pneumatic controller, will this trigger applicable requirements to other older, existing pneumatics that remain at the facility?
   - The MSC encourages U.S. EPA to establish a threshold (e.g., count of components) under which OOOOc does not apply, where the emission reductions would be minimal but expensive to achieve.

4. For existing sources under Subpart OOOOc, requiring zero bleeds without any other options at existing facilities is currently not practical. Technical feasibility has not been demonstrated. Solar power and associated battery storage is not feasible to power an air compressor, and may even be insufficient to power electric-driven controllers at some facilities due to significant electrical demand. While there may be some pilot projects

within industry, it has not been demonstrated that reliable turnkey packages are available en masse. Any implementation should have a phased timeline to allow for adequate availability.

5. The MSC requests that the Agency include the option to send to a control device or route to a process. Similar to Subpart OOOOa, this will be primarily those with existing control devices or processes. Adding a control device specifically for pneumatics would be hindered by cost (older, low-producing pads and smaller facilities), availability, and other constraints such as spacing of a combustion device (setbacks, safety, and smaller locations that may lack the room).

6. If a combustion device is used for control, the MSC recommends that operators should be able to utilize a manufacturer-tested device (i.e., "U.S. EPA certified" for storage tanks) or if electing to use one not on that list, or engineer one themselves, operators should be able to do a performance test or engineering demonstration themselves.

7. The MSC encourages the Agency to provide an exemption from non-emitting requirements for temporary sources.

8. The MSC requests that U.S. EPA confirm emergency shutdown valves or devices are not pneumatic devices (e.g., most compressor skids have pneumatic controllers which use natural gas system pressure as a fail-safe open or close when electric power is interrupted. These controllers will normally not operate or have emissions unless the operational upset requires a safe shutdown).

9. If the non-emitted system (i.e., instrument air) goes down, there is no provision within the proposed rulemaking to allow for the temporary use of natural gas. If the instrument air system fails, many valves used within industry are fail-close, which will create significant challenges for an interconnected industry. The MSC urges U.S. EPA to evaluate the reliability and availability of such systems that would be deployed at such breadth.

WELL LIQUID UNLOADING

1. The MSC requests that U.S. EPA focus requirements on liquid unloading events resulting in venting and not the "design" of the liquid unloading method. The "design" of the methods, venting or non-venting, is not relevant. The current GHG reporting rule (i.e., 40 CFR 98 Subpart W) reporting elements, (i.e., gas wells that vent) should be maintained as the basis for a liquid unloading affected facility.

2. For reporting of liquid unloading events that result in vented emissions, U.S. EPA currently requires reporting of liquid unloading vented emissions under GHGRP 40 CFR Part 98 Subpart W using Equations W-7, W-8, or W-9 of §98.233(f). MSC urges U.S.

EPA to consider existing data reported under this Subpart and not impart additional unnecessary reporting requirements.

3. Almost all wells experience liquid unloading during the natural production of the well, many without any equipment modification and as a stage of "primary" production. Even gas wells that do not contain any movable liquids in the formation will generate liquids due to condensation of the liquid vapor in the gas as the gas cools during production from the downhole formation to the surface wellhead. With time this liquid can accumulate in the wellbore and can temporarily load the well until the well pressure increases naturally under this fluid column until there is sufficient pressure/ energy to unload the liquid column. Unloading is not necessarily a physical or operational change and does not result in the potential for increased emissions when wells do not vent as previously mentioned. Therefore, the unloading activities should not be considered a modification.

4. With respect to the affected facility definition options, MSC offers the following comments:

- Option One would apply to almost all wells, and therefore should be eliminated, since almost all wells experience liquid unloading. The application of Option One would therefore apply to almost all wells, even wells that are still producing naturally without any added artificial lift technology. This would be an unreasonable record keeping request and therefore Option One should be eliminated from the proposed rule.

- MSC supports Option Two solely for gas wells that actually vent. Reporting for wells that do not vent is burdensome, with no emission benefit, and too broad in scope. Affected facility would be defined as every well that undergoes liquids unloading using a method that vents. Wells that utilize non venting methods would not be affected facilities that are subject to the NSPS OOOOb. Therefore, they would not have requirements.

5. MSC supports the use of BMPs when venting is required for liquid unloading. As proposed "for unloading technologies or techniques that result in venting to the atmosphere, implement BMPs to ensure that venting is minimized. Maintain BMPs as records, and record instances when they were not followed." MSC supports liquid unloading BMPs that empower production engineers to direct unloading activities without technical justification and that are aimed at daily operational venting minimization.

6. MSC supports BMPs that:
   - Require the reporting of vented emissions as per "Gas Well Venting for Liquids Unloading according to Petroleum and Natural Gas Systems source category of the GHGRP 40 CFR Part 98 Subpart W using Equations W-7, W-8, or W-9 of §98.233(f)".

- That require an operator at the wellsite or in close proximity unless the use of automation equipment, remote sensors, and other surveillance technologies are used.
- That require the operator to report when the BMPs have not been followed.
- Allow for the use of flaring as a control option.
- Allow for routing emission to a sales line or back to a process.
- For states where a BMP governing liquid unloading event is required under the states' regulations (e.g., permit requirements), such BMPs should be deemed sufficient and satisfy the requirements of NSPS.

7. MSC objects to BMPs with any of the following requirements as they would be a record keeping and reporting burden with no direct emission reduction benefit:
   - Technical justification for the unloading methodologies employed.
   - Process flow explanation and or diagrams of unloading activities.
   - Historical account of all activities associated with attempts to unload wells.

   MSC agrees per page 63211 that "Selecting a particular method to meet a particular well's unloading needs must be based on a production engineering decision that is designed to remove the barriers to production."

   Describing clearly where a well stream is directed via a process flow diagram and explanation is not in most cases a trivial explanation. Many well sites, especially sites with multiple wells, have a complex surface piping system for equipping the site with the various liquid unloading activities that could result, (e.g., gas injection, recirculation of produced gas in wellsite compression, VRU control options, combustors, oxidizers, multiple use of separators and tanks often manifolded together, soap and chemical delivery systems). The current reporting methodology options in calculating annual natural gas emissions from Gas Well Venting for Liquids Unloading according to Petroleum and Natural Gas Systems source category of the GHGRP 40 CFR Part 98 Subpart W using Equations W-7, W-8, or W-9 of §98.233(f) are adequate.

8. MSC objects to BMPs with any of the following as they would be a safety concern:
   - Requirement for the direct measurement of vented emissions.
   - Requirement for an operator to be in close proximity to the unloading activities when the use of automation equipment, remote sensors, and other surveillance technologies are used.

   An emission quantification hierarchy of direct measurement, engineering equations, and emission factors will for almost all sources result in the most accurate emission values. However, engineering challenges, economic criteria, and safety considerations will result in the optimal selection on a case-by-case basis.

There are safety concerns regarding direct measurement of venting emissions. NIOSH-OSHA have issued a Hazard Alert[5] associated with working around open top tanks. This Hazard Alert describes the safety and health hazards when workers manually gauge or sample fluids from production, flowback, or other tanks. It recommends ways to protect workers by eliminating or reducing exposures to hazardous atmospheres, and actions employers should take to ensure that workers are properly aware of the hazards and protected from exposure to hydrocarbon gases and vapors. This alert is a supplement to the OSHA Alliance Tank Hazard Alert released in 2015 [National STEPS Network 2015]. Although there are many cases of direct measurement being performed on methane emissions many of them are done in a controlled experimental environment. In reality, workers should use extreme caution whenever working around hydrocarbon emissions and many of the direct measurement techniques used and suggested (see [3]CCAC Appendix A: Conducting Emission Surveys, Including Emission Detection, and quantification equipment, which include turbine meters, vane anemometers, hotwire anemometers) actually expose workers to these emissions and therefore should be avoided.

9. MSC object to BMPs with prescriptive requirements for using any specific unloading technology, such as the requirement to try a plunger lift, or attempt the use of an artificial lift engine, both of which can be found in the New Mexico draft language. Requirements that are too prescriptive in nature and would potentially impact the Production Engineer's best design decisions should be avoided.

10. MSC offers the following examples that would not allow liquids unloading to be performed without venting:
    - Production Engineers should be empowered to make the best production decision, and when they decide venting is required, it should be considered technically necessary.
    - Many wells need to unload to an atmospheric tank for unloading to be successful.
    - Sporadic unloading is difficult to model and the selection of surface equipment that does not vent creates safety concerns.
    - Separation equipment requires threshold operating pressures and perform poorly under sporadic flow.
    - The use of compressed nitrogen to unload wells often requires some venting.
    - High surface producing pressures can result from gathering and compressor system maintenance or unplanned upsets. Wells often cannot unload against these higher surface pressures.
    - Locations are often too small to accommodate the significant amount of equipment which would be necessary for non-venting liquids unloading.

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[5] Health and Safety Risks for Workers Involved in Manual. Tank Gauging and Sampling at Oil and Gas Extraction Sites. https://www.osha.gov/sites/default/files/publications/OSHA3843.pdf

11. The routing of emissions back to a sales line is possible but not always practical and creates secondary emissions. One operator uses mobile gas lift compressors (MGLC) to unload wells to minimize venting emissions. Estimated cost for routing unloading emissions to the sales line using mobile gas lift wellsite compressors for one operator cost $280K/year. The equipment size, layout, spacing requirements (Fire Class/Divisions), and cost would make it difficult to justify for use on marginal or remote wells. The secondary emissions from the model 3406 gas powered compressor are approximately 4 tons/event CO_2e.

12. The BSER analysis for velocity strings was incomplete and generally not applicable to a wide variety of unloading challenges. MSC offers the following comments:

    - The BSER analysis for use of velocity strings is not applicable to fields where the potential for frac hits exists during normal prudent field development. In these cases, a significant amount of water will result in legacy offset wells and velocity strings will make the recovery and deliquification of these wells extremely difficult or impossible as the tubing conduit, with reduced diameter, would create significant friction and back pressure.
    - Velocity strings also are very difficult to unload and swabbing and plunger options are either reduced or eliminated due to the small diameter.
    - Velocity string sizing requirements change with time requiring replacement. They are therefore not considered permanent solutions for liquid unloading. The increased emissions and cost was not considered in the BSER analysis.

13. The CAA section 111(a) requires that U.S. EPA promulgate a standard that "has been adequately demonstrated" based on technical feasibility and cost effectiveness. MSC questions U.S. EPA on the methodology that was employed to establish cost reasonableness:
    - U.S. EPA is to establish $/tons of emission reduction in establishing reasonableness, yet there is no data on emission reductions in the analysis. U.S. EPA acknowledged that establishing an emission reduction that would be achievable by event is difficult as baseline level of management practices and emissions varies significantly. Therefore, U.S. EPA calculated the $/ton reduction from the baseline level based on hypothetical values of 10%, 25%, and 50%. As stated, these are hypothetical values and therefore, questionable as representing reduction per event. Additionally, the baseline emission is a crucial factor in calculating the tonnage of reduction; yet, U.S. EPA lacks transparency in providing justification for the baseline emissions applied in the calculation of cost effectiveness. As such, MSC questions U.S. EPA on the cost effectiveness of the "Non-Emitting Evaluation" option.
    - To establish the cost effectiveness for existing sources (i.e., wells already equipped with "non-venting" technology such as plunger lift), the U.S. EPA's analysis is based on 2015 – 2019 liquid unloading data from Subpart W. The data shows 98% of "with plunger" wells are those equipped with automated plunger for which U.S. EPA cannot establish an emission reduction baseline. Hence, the analysis is based on the

remaining 2% of the well population representing manual liquid unloading operation. MSC questions the representation of this analysis since 98% of actual wells are equipped with automated plunger system from which U.S. EPA cannot establish actual reduction.

14. The American Exploration and Production Council has developed comprehensive comments related to well liquid unloading. The MSC offers its support and endorsement of these comments.

RECIPROCATING COMPRESSORS

1. U.S. EPA should adopt both a fixed schedule option and a condition-based option as alternative standards for the replacement of rod packing at reciprocating compressors. In the Subpart OOOOa rulemaking, U.S. EPA adopted a fixed-schedule rod packing replacement standard. U.S. EPA determined that a standard requiring the replacement of rod packing for reciprocating compressors on a fixed schedule, every 3 years or 26,000 hours of operation, was BSER. In the Proposed Rules, U.S. EPA notes that a condition-based standard—requiring annual monitoring and replacing of the rod packing if the measured flow rate for an individual cylinder exceeds 2 scfm—is also BSER for reciprocating compressors. MSC recommends that U.S. EPA provide operators the option of utilizing a fixed schedule or condition-based option for the replacement of rod packing. Similar emission reductions are anticipated under either option. Allowing a fixed schedule option allows companies consistency with OOOOa and voluntary programs, would maintain consistency with state permit conditions or requirements, and allow flexibility for existing compressors under Subpart OOOOc. The condition-based option can also be beneficial as an approach to extend the operational life of the rod packing and avoid unnecessary maintenance.

2. Clarification regarding the timing for required rod packing replacement under a condition-based standard is needed. Rod packing replacement is a major maintenance activity that must be done during an equipment shutdown. This maintenance must be allowed to be properly scheduled and in order to minimize unnecessary interruptions to operations. MSC recommends that replacement be required at the next planned shutdown for maintenance.

3. MSC requests clarification regarding testing if a conditioned-based standard is adopted. It is common practice to manifold the rod packing vents together. Operators should be allowed to measure flow rate from the manifold and average based upon the number of throws collected.

CENTRIFUGAL COMPRESSORS

1. U.S. EPA should not require controls on low-emitting wet seal compressor under Subparts OOOOb or OOOOc. Some existing centrifugal compressors use wet seals that produce very low emissions and should not require controls. Emissions from wet seals are generated when hydrocarbons are removed from the seal's oil. This is also known as being de-gassed. Some manufacturers collect these hydrocarbons and route them back into the process. Solar Turbines utilizes one such system. Solar's testing and modeling shows the residual natural gas volume vented is less than 1% of the total degassed natural gas volume. California's Greenhouse Gas Emissions Regulation (17 CCR § 95668(d)(6)) requires wet seal compressors to install controls similar to Subpart OOOOa, such as routing to a process, or perform annual monitoring based on a leak rate of 3 standard cubic feet per minute.

ATTACHMENT 1

Liquid Unloading Supporting Information

Supporting Information – Comment 1

U.S. EPA co-proposed options to use "the wells' designed unloading methods and whether the methods are designed to vent or not as the determination basis for an affected facility" would create significant ambiguity. The design of a well's liquid unloading strategy often has multiple possible outcomes depending on various factors that can change daily (e.g., operating temperatures and pressures, reservoir behavior, gathering and compression systems, offset well affects, availability of equipment and personnel, and the actual daily history of unloading attempts). Any attempts to define affected facilities based on whether a well is designed to vent during unloading or not would be problematic as both design possibilities may exist concurrently.

All wells will eventually require liquid unloading and the methods to unload liquids throughout the life of the well will change depending on the condition of the well. As the well matures, a method that is successful in routing the well stream to a separator with no venting, may eventually cease to unload liquids due to changes in well conditions. For example, a well is equipped with a plunger system to route the well stream to a separator and subsequently, sending gas to the sales line with no venting. Changes in well conditions leading to insufficient pressure differential to unload liquid would require unloading to an atmospheric storage tank with minimal venting. In this scenario, U.S. EPA should only require reporting of the events that result in venting and omit any references to the non-venting "design" of the liquid unloading method as it is not relevant in terms of the intent of the rule (i.e., minimizing vented emissions and the inherent ever-changing conditions of the wells).

In terms of recordkeeping, U.S. EPA must consider existing data as reported under Subpart W to account for liquid unloading events resulting in vented emissions. It is not warranted to maintain records for non-venting events. Additionally, the lack of a framework for what constitutes a non-venting event renders it impractical or not possible to qualify or quantify a non-venting event. For example, the time period when a well equipped with a plunger system which sends the well stream directly to a separator with no vented emissions would qualify as a non-venting period. It is unclear how liquid unloading events during this period would be quantified (e.g., a count of plunger cycles that successfully lift liquids and unload). From this perspective, U.S. EPA should omit any considerations in regard to record keeping and reporting requirements for non-venting liquid unloading events.

Supporting Information – Comment 5

Almost all non-venting liquid unloading events are done against a surface back pressure that is greater than atmospheric pressure. Even small amounts of back pressure (single digit psi increases) could make the difference on whether an unloading attempt is successful or not. Many wells will not unload against surface back pressure and therefore require venting to the atmosphere.

MSC agrees with the following:

- Pg. 63180: "However, U.S. EPA recognizes that there may be reasons that a non-venting method is infeasible for a particular well, and the proposed rule would allow for the use of BMPs to reduce the emissions to the maximum extent possible for such cases (discussed in section XII.D of this preamble)."

- Pg. 63213 "The EPA recognizes that there may be safety and technical reasons why venting to the atmosphere is necessary to unload liquids. In addition, it is possible that a well production engineer has already explored non-venting options and determined that there was no feasible option due to its specific characteristics and conditions."

- Pg. 63211 "Selecting a particular method to meet a particular well's unloading needs must be based on a production engineering decision that is designed to remove the barriers to production."

Based on the previous three statements, it should be evident that if there was a solution that did not require venting it would have been selected by the Production Engineer.

<u>Supporting Information – Comment 6</u>

Automation:
Although many member companies employ the Best Practice Implementation Principle as outlined in the API's The Environmental Partnership Program for Manual Liquids Unloading (operators commit to monitoring the manual unloading process and close all wellhead vents to atmosphere) it is important to point out that the following definitions apply:

- Manual Liquids Unloading: an operation undertaken by an operator to temporarily divert the flow from the well to an atmospheric vent without assistance of automated equipment.
- Monitored: operator on-site or in close proximity and able to close atmospheric vent as soon as practicable to minimize the gas vented to atmosphere.

The use of automation is a very important point in this BMP formulation. The use of remote sensors, mechanically activated devices, positive closure and seal indicators, camera technology, and associated surveillance and alarming can greatly enhance the effectiveness of optimal liquid unloading and in many cases is more effective than relying on personnel to be on site. Therefore, any BMP should not require having a person onsite during the liquids unloading event to expeditiously end the venting when the liquids have been removed as suggested on page 63179. Rather, BMPs should encourage the continued use and expansion of use of automation technologies that are very scalable and economic.

Automation also reduces the safety risk of exposing personnel to hazardous atmospheres.

U.S. EPA states that based on the report (*U.S. Environmental Protection Agency. Oil and Natural Gas Sector Liquids Unloading Processes. Report for Crude Oil and Natural Gas Sector Liquids Unloading Processes Review Panel. April 2014*) and peer reviews on the technical and cost feasibility of using a flare to control vented emissions from liquids unloading events indicating that a flare cannot be used in all situations, we did not consider this option any further in this proposal. One cited peer review (Jim Bolander, P.E., Senior Vice President, Southwestern Energy (SWN). Review Submitted: April 2014. Pg. 8) stated "The flowing characteristics during venting operations inhibit the design of flare equipment. During the unloading operation, initial gas flow rate and pressure are high and decline rapidly over a short time period. Flare design (tip diameter) is based on flow rate and design criteria can be found in public documents (Chapter 7 FLARES: Diana K. Stone, Susan K. Lynch, Richard F. Pandullo, Radian Corporation Research Triangle Park, NC 27709, Office of Air Quality Planning and Standards U.S. Environmental Protection Agency, Research Triangle Park, NC 27711, December 1995). In addition, the sporadic nature of liquid unloading venting operations would require either a continuous pilot or electronic igniter. The design cost associated with the requirements needed for this type of flow would be cost prohibitive." Additional information for flare applicability in this context is available in U.S. EPA Gas Star PRO Fact Sheets No. 904 "Install Flares" and No. 903 "Install Electronic Flare Ignition Devices".

While the conclusion to not consider a flare as a control option for liquids unloading venting could be supported in some cases, there are opportunities to use flares in many cases, and these cases are likely the ones that have the biggest opportunity for methane emission reductions. As an example, consider the methods of liquid unloading that use an artificial lift engine (i.e., gas lifting the fluids with compressed gas). In this example, the well still may require a very low surface pressure to effectively remove the liquids, and the quantity of produced gas could be significant before it can be directed to sales or recirculated into a gas compressor intake. Certainly, a flare as a control device in this situation would be technically feasible and likely result in a safer operation. Therefore, flares (and enclosed combustion devices and thermal oxidizers) should be considered as a control option in this proposal.

Production Engineers will always attempt to capture methane emissions and put them into the sales line when practical. During plunger lift, gas lift assist, soap assist, venturi system lift, swabbing, and many other forms of liquid unloading, gas is often captured and routed to sales or to a control device (e.g., flare, compression input, heaters, generators). As noted in the preamble, "selecting a particular method to meet a particular well's unloading needs must be based on a production engineering decision that is designed to remove the barriers to production." In many cases there are ways to achieve this with going to sales or a control device, but when they no longer can do so, they still require the ability to vent. There are many Gas Star PROs that address the cost side of these solutions that are highly variable.

In various state approved BMPs (New Mexico, Pennsylvania, and Colorado), there are common elements which are non-prescriptive and allows for operators' expertise in the selection of appropriate liquid unloading practices. The commonality or consistencies of these elements reflects recognized and common practices that are proven. MSC recommends that U.S. EPA consider the application of these common elements in determining the minimum elements requirements. One such common practice is to require monitoring during a liquid unloading event via the presence of an operator on-site or in close proximity. The application of remote monitoring via sensor technology may also be employed as a feasible option.

Supporting Information – Comment 10

Almost all non-venting liquid unloading events are done against a surface back pressure that is greater than atmospheric pressure. Even small amounts of back pressure (single digit psi increases) could make the difference on whether an unloading attempt is successful or not. Many wells will not unload against surface back pressure and therefore require venting to the atmosphere.

Due to the very sporadic nature of liquid unloading operations, attempts to contain the surging fluids and gases becomes a very difficult design problem. Engineering equations are not available to accurately estimate the pressure effects as the fluid stream reaches the surface equipment. Therefore, having a totally closed system without the ability to vent to the atmosphere in many cases creates a safety concern (e.g., potential bursting of tanks). To completely prevent any issues like the bursting of separators or tanks, while keeping the surface pressures low, the surface equipment would need to be designed with safety factors that would result in significantly overrated and oversized equipment along with the associated excessive cost. This is not a practical solution, especially for low producing wells.

Much of the surface equipment needed for the separation of gas from liquids requires a threshold operating pressure and a flow regime that is not significantly sporadic. To be able to measure and control unloading emissions, this separation would need to be completed. This is often not practical unless tanks that can vent to accumulate the sporadic flow stream are used, which allow for liquid/gas gravity separation over time.

The use of compressed nitrogen to unload wells is common practice, especially when a well does not have the ability to use produced gas (e.g., a single well on a location, an exploration type well without any gathering infrastructure). Since the unloading gas stream will be a mixture of the injected nitrogen and formation gas, the gas will have too high a nitrogen content to put in a sales line or to burn efficiently via a flare. Until the mixture can go to beneficial use, some venting may be necessary. These operations make all attempts to minimize this venting typically with a recirculation system.

In certain basins / formations, a temporary shut-in to build pressure does not build enough delta between bottomhole pressure and surface pressure to overcome the production impediment caused by liquid holdup. Therefore, unloading to a low-pressure system is required. For some low-pressure wells on compression, it may be problematic for them to build up enough line pressure to exceed line pressure to effectively unload water. There are pressures and/or gas rates where liquid unloading to the atmosphere should be permissible to account for this scenario.

A non-venting solution may be possible in almost all cases but the amount of equipment, additional artificial lift engines and associated secondary emissions often makes this an obvious poor choice (without consideration of economic realities). Location and size can also prevent the installation of any such equipment, particularly when adequate and prudent spacing between wellheads and other potential ignition sources and fired equipment such as compressor exhaust and flares. Production Engineers are professional problem solvers, and they should be empowered to come up with the best solutions as alluded to in the preceding comments.

ATTACHMENT 2

Appendix K Comments

General Comment
It is not clear what it takes to become a "certified" Senior OGI Camera Surveyor initially. Do they train and audit themselves? Clarification on what U.S. EPA envisions as the requirements to receive initial certification would be helpful.

Section 3.0 Definitions
Senior OGI camera operator – the definition states a minimum of 500 sites. It appears that the intent is for 500 different surveys as stated at U.S. EPA's Optical Gas Imaging Stakeholder Workshop, November 9-10, 2020. Suggest rewording to agree with findings of the presentation.

- Additionally, the threshold for obtaining senior operator status is difficult to achieve and will result in fewer surveyors being immediately available to complete the surveys required under the rule due to excessive training requirements. Number of sites or surveys on its own is a poor indicator of experience and qualification of the camera operator. We suggest that the threshold for senior operator status be lowered or that an intermediate status with a lower survey threshold be established to have more camera operators immediately qualified to complete surveys.

Dwell Time – holding the camera "steady" is often a poor practice for finding leaks with an OGI camera, particularly in HSM mode. It is often much better to "pan," or slowly move the camera across a scene, to avoid screen flickering and aid in seeing plume movement.
General Comments on Definitions

- Suggest that the term "survey" be defined and references to "sites" throughout the Appendix be changed to "survey."

Section 4.0 Interferences – although interferences from atmospheric conditions such as fog, mist, rain, and solar glint may have an impact an OGI operator's ability to detect leaks, they do not fully eliminate the OGI operator's ability to determine the presence and location of emission points. Consequently, OGI surveys should not be prohibited during such periods of non-ideal atmospheric conditions.

Sections 6.0 Equipment and supplies – The specifications need to be placed on the OGI camera manufacturer so that the operator can rely on manufacturer specifications. For example, under NSPS OOOOa, the major camera manufacturers have published documents indicating compliance with the "initial verification" requirements of the rule following third-party testing.

6.1.2 – Why did U.S. EPA select butane instead of propane for evaluation of performance? Propane will, overall, be the predominant constituent in natural gas compared to butane.

Section 8.0 Initial Performance - control devices of 40 CFR, 60.5413a(d), provisions should be developed to allow operating envelopes to be developed by the OGI manufacturer and methods of continuous compliance for operators using manufacturer's demonstrated techniques.

8.5.3 – a panel of observers where only 3 of the 4 need to observe the emissions to be considered valid contradicts the requirement in Section 10 that a trainee must be 100% accurate to be able to conduct surveys independently.

Section 9.0 Conducting the Monitoring Survey –
9.2.1 – Delta T is highly variable even at a single facility. It is not possible to have a single "expected delta T".

9.2.2 – There is only one way to "monitor Delta T", and one camera which can do it (FLIR GF series). To fulfill this proposed requirement, i.e. "monitor delta T", an operator must continuously concentrate on viewing a calculated number on the screen (the difference between the air temperature and the averaged "scene temperature" the camera is reading", instead of focusing on visually interpreting the screen images to find potential leaks. Extensive field testing utilizing a method which obsessively focuses on extreme delta T limitations has led to finding less leaks, which negates its perceived advantages. Additionally, when surveying in HSM mode (the primary mode of many camera operators), plume movement is much more important than large delta Ts – and plume movement is always present in a gas leak scenario due to the high-pressure gas escaping to atmosphere. Proper training, experience and general operating principles (ex. ensuring the camera is set to the appropriate general temperature range to image the equipment in the scene) is much more important and aids in effectively finding leaks.

9.3 – The use of a component database for an OGI-based LDAR program is inappropriate, in fact it negates one of the major advantages of OGI (basically relegates it to Method 21 with different detection equipment).

9.4 – Dwell times of at least 5 seconds from at least 2 different angles per component is excessive and provides no added efficiency in detecting leaking components. This requirement will result in vastly increased survey times requiring additional staff and equipment resources without a significant environmental benefit. We recommend that this requirement be removed.

- As an example, an average Pennsylvania well pad may include 2,500 fugitive components and can be effectively imaged using NSPS OOOOa procedures in approximately 1.5 hours. To do the same facility using the proposed requirements in Appendix K would take seven hours to complete, not counting any additional time for initial procedures or leak repair efforts. U.S. EPA has shown no justification for these arbitrary and capricious requirements and is attempting to limit all advantages that OGI has over traditional techniques such as Method 21.

9.5 – Operator fatigue is unique to each camera operator and survey situation. Generally, the camera operator is not continuously surveying from a fixed location for an extended period of time and thus has frequent small survey breaks moving from location to location. We recommend that this requirement be removed.

9.6.2 – "Major process area" is not defined, nor should it be defined or included in this procedure. Also, recording conditions at the end of the survey only serves to collect data which

would be used to scrutinize or invalidate collected survey data (though so long as the camera operator utilized proper technique would not be the case).
9.7.1 – A 10-second video clip for detected leaks is excessive. To have a more proficient LDAR program, surveys are conducted with appropriate staff so that detected leaks are repaired simultaneously when possible. A color still image serves the same purpose and provides a clearer and more detailed image while enabling more efficient use of survey time.

9.7.3 – Five minutes for the daily QA verification video is excessive. Additionally, the required quarterly audits, annual training and daily equipment startup checks make this requirement redundant and already adequately ensure survey quality.

Section 10.0 Camera Operator Training
10.2.2 – Training requirement will be difficult and costly for smaller companies that don't have multiple cameras/camera operators to comply. The number of site surveys conducted in tandem with a senior operator seem arbitrary and overly onerous. To mitigate this we suggest that number of surveys criterion be replaced with a time requirement with a set number of survey hours for each training phase because a survey may vary greatly in duration depending on the type of facility being surveyed.

10.2.2.4 - The requirement of achieving zero missed persistent leaks is higher than the amount achieved by all levels of experience in the Camera-Focused Studies, as presented at U.S. EPA Optical Gas Imaging Stakeholder Workshop, November 9-10, 2020. Please note that 100% detection for flow rates was never achieved for the camera focused studies. We suggest that the threshold be revised to an allowable percentage of missed persistent leaks rather than an arbitrary number because it will be scalable regardless of the number of components being monitored in the survey.

10.3 – While generally supportive of refresher training, we suggest that camera operators should be exempted from the annual refresher training requirement if the operator is conducting frequent surveys throughout the year and passes all performance audits since their last completed training.

10.4 – Quarterly audits are excessive and will result in more obligations for the limited number of qualified camera operators. Annual audits would be a more reasonable frequency.

10.4.1.1 – The requirement for a 4-hour survey by the senior operator is arbitrary and may not be applicable if the site being audited is a small compressor station or a well pad where the original survey would not meet that time requirement. Additionally, we believe there will be a shortage of qualified senior operators and that any qualified camera operator should be able to conduct an audit on another camera operator.

10.4.1.2 – As stated above the requirement of achieving zero missed persistent leaks is unrealistic and should be revised to an allowable percentage of missed leaks before retraining is required.

10.4.2 – This protocol shows a lack of understanding for how OGI camera programs and surveys work in real life, because reviewing video footage collected by another surveyor is useless from an auditing standpoint. Video review forces the auditor to only utilize data collected via the methods and procedures of the surveyor – not utilizing their own skills to compare results. Additionally, the video clips captured via OGI cameras are generally poor when compared to the way that the live screen image appears through the viewfinder or LCD screen during the survey.

12.2.3 – Why are records retention requirement being applied here for the lifetime of equipment, when the survey records themselves might only be required to be kept for 5 years (or other regulatory requirement)?

14 – MSC recommends that this section be removed. This is wholly inconsistent with what experienced camera operators would do – i.e. those most skilled in finding leaks. This is also not technically feasible due to the requirement to continuously measure distance and count components to determine the applicability of the table. The burdensome nature of all proposed requirements related to "dwell time" cannot be overstated. Furthermore, a common practice is to find a single leaking component within a cluster of components (quite efficient) and then locate the actual egress point (i.e. individual leaker) by simply moving closer at various points within the area until the leak it identified.