Final Report

of the

Small Business Advocacy Review Panel on

EPA's Planned Proposed Rule

Emission Standards for New, Reconstructed, and Modified Sources in the Oil and Natural Gas Sector

September 2021

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1 INTRODUCTION

This report document is the findings of the Small Business Advocacy Review Panel (SBAR Panel or Panel) convened to review the planned proposed rulemaking on the Emission Standards for New, Reconstructed, and Modified Sources in the Oil and Natural Gas Sector. Under section 609(b) of the Regulatory Flexibility Act (RFA) as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), a Panel is required to be convened prior to publication of the initial regulatory flexibility analysis (IRFA) that an agency may be required to prepare under the RFA. In addition to EPA's Small Business Advocacy Chairperson, the Panel members are the Director of the Sector Policies & Programs Division within the EPA's Office of Air and Radiation, the Acting Administrator of the Office of Information and Regulatory Affairs within the Office of Management and Budget, and the Acting Chief Counsel for Advocacy of the Small Business Administration.

Section 609(b) of the RFA directs the Panel to consult with and report on the comments of small entity representatives (SERs) and make findings on issues related to elements of an IRFA under section 603 of the RFA. Those elements of an IRFA are:

- A description of, and where feasible, an estimate of the number of small entities to which the proposed rule will apply;
- A description of projected reporting, record keeping, and other compliance requirements of the proposed rule, including an estimate of the classes of small entities which will be subject to the requirement and the type of professional skills necessary for preparation of the report or record;
- An identification, to the extent practicable, of all relevant Federal rules which may duplicate, overlap, or conflict with the proposed rule; a description of any significant alternatives to the proposed rule which accomplish the stated objectives of applicable statutes and which minimize any significant economic impact of the proposed rule on small entities. This analysis shall discuss any significant alternatives such as:
    - the establishment of differing compliance or reporting requirements or timetables that take into account the resources available to small entities;
    - the clarification, consolidation, or simplification of compliance and reporting requirements under the rule for such small entities;
    - the use of performance rather than design standards; and
    - an exemption from coverage of the rule, or any part thereof, for such small entities.

In addition to the elements above, this report includes the following:

- Background information on the proposed rule being developed;

- Information on the types of small entities that may be subject to the proposed rule;
- A description of efforts made to obtain the advice and recommendations of representatives of those small entities; and
- A summary of the comments that have been received to date from those representatives.

Once completed, the Panel Report is provided to the agency issuing the proposed rule and is included in the rulemaking record. The agency is to consider the Panel's findings when completing the draft of the proposed rule. In light of the Panel Report, and where appropriate, the agency is also to consider whether changes are needed to the IRFA for the proposed rule or the decision on whether an IRFA is required.

The Panel's findings and discussion will be based on the information available at the time the final Panel Report is drafted. EPA will continue to conduct analyses relevant to the proposed rule, and additional information may be developed or obtained during the remainder of the rule development process.

Any options identified by the Panel for reducing the rule's regulatory impact on small entities may require further analysis and/or data collection to ensure that the options are practicable, enforceable, environmentally sound, and consistent with the Clean Air Act and its amendments.

2 BACKGROUND AND DESCRIPTION OF RULEMAKING

2.1 Regulatory History

In 2012, the EPA published the final rule, "Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution," 77 FR 49490 (40 CFR part 60, subpart OOOO) ("2012 NSPS OOOO"). This rule established VOC standards for several oil and natural gas-related operations emission sources, including natural gas well completions, centrifugal and reciprocating compressors, natural gas operated pneumatic controllers, and storage vessels. EPA amended 2012 NSPS OOOO in 2013, 2014, and 2015.

In 2016, the EPA published a final rule, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Final Rule," 81 FR 35824 (40 CFR part 60, subpart OOOOa) ("2016 NSPS OOOOa"). The 2016 NSPS OOOOa rule established NSPS for sources of GHG (in the form of limitations on methane emissions) and VOC emissions for certain equipment, processes, and operations across the oil and natural gas industry. The 2016 NSPS OOOOa addresses the following emission sources:

- Sources that were unregulated under the 2012 NSPS OOOO (hydraulically fractured oil well completions, pneumatic pumps, and fugitive emissions from well sites and compressor stations);
- Sources that were regulated under the 2012 NSPS OOOO for VOC emissions, but not for GHG emissions (hydraulically fractured gas well completions and equipment leaks at natural gas processing plants); and
- Certain equipment that is used across the source category, for which the 2012 NSPS OOOO regulates emissions of VOC from only a subset of the equipment (pneumatic controllers, centrifugal compressors, and reciprocating compressors, with the exception of compressors located at well sites).

In 2018, the EPA finalized amendments of certain aspects of the 2016 NSPS OOOOa requirements for the collection of fugitive emission components at well sites and compressor stations, specifically (1) the requirement that components on a delay of repair must conduct repairs during unscheduled or emergency vent blowdowns, and (2) the monitoring survey requirements for well sites located on the Alaska North Slope.

In 2020, the EPA published two final rules to amend the New Source Performance Standards. Published on September 14, 2020, the first of the two rules is titled, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review." Commonly referred to as the 2020 Policy Rule or Methane Recission Rule, it removed the transmission and storage segment from regulation on the basis that this segment is not "sufficiently related" to production and processing, and therefore cannot be part of the same source category. The 2020 Policy Rule also rescinded methane requirements for the industry's production and processing segment on the basis that such standards are redundant to VOC standards for this segment. Lastly, the rule interpreted CAA 111(b) to require, or at least authorize the Administrator to require, a pollutant-specific "significant contribution finding" as a prerequisite to regulating a new pollutant, that is supported by criteria or a threshold for determining "significance;" rescinded methane requirements for the industry's production and processing segment on the separate basis that EPA had failed to make that finding.

Published on September 15, 2020, the second of the two rules is titled, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration." Commonly referred to as the 2020 Technical Rule and finalized exempting low-production well sites from fugitives monitoring (previously required semiannually), required semiannual monitoring at gathering and boosting compressor stations (previously quarterly), streamlined recordkeeping and reporting requirements, allowed compliance with equivalent state requirements as an alternative to NSPS fugitive requirements, streamlined application to use new technologies to monitor for fugitive emissions, addressed storage tank batteries for applicability determination purposes and finalized several technical corrections. The 2020 Policy Rule amended 40 CFR part 60, subparts OOOO and OOOOa, as finalized in 2016. The Technical Rule amended the 40 CFR part 60, subpart OOOOa, as amended by the Policy Rule.

On June 30, 2021, President Biden signed into law a joint resolution of Congress, adopted under the Congressional Review Act (CRA), disapproving the 2020 Policy Rule. The CRA resolution has the effect of reinstating the VOC and methane standards for the transmission and storage segment, as well as the methane standards for the production and processing segments. The CRA resolution did not address the 2020 Technical Rule; therefore, those amendments remain in effect.

2.2 Description of Rulemaking and its Scope

On January 20, 2021, President Biden issued Executive Order (EO) 13990, "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis." EO 13990 describes the Administration's policy "to improve public health and protect our environment; to ensure access to clean air and water; to limit exposure to dangerous chemicals and pesticides; to hold polluters accountable, including those who disproportionately harm communities of color and low-income communities; to reduce greenhouse gas emissions; to bolster resilience to the impacts of climate change; to restore and expand our national treasures and monuments; and to prioritize both environmental justice and the creation of the well-paying union jobs necessary to deliver on these goals."

EO 13990 directs the EPA to consider proposing a rulemaking to reduce methane emissions in the Oil and Natural Gas source category by suspending, revising, or rescinding previously issued new source performance standards. It also instructs the EPA to consider proposing new regulations to establish comprehensive standards of performance and emission guidelines for methane and VOC emissions from existing operations in the oil and natural gas sector, including the exploration and production, processing, transmission, and storage segments.

In response to EO 13990, the EPA is proposing an NSPS to include new or amended standards for GHG and VOC emissions for certain new, modified, and reconstructed equipment, processes, and activities across the oil and natural gas source category. The proposed NSPS OOOOb would apply to sources which are new, reconstructed, and modified following the date of publication of the proposed rule.

As part of this rulemaking, EPA will also discuss the impact of the CRA resolution of disapproval of the 2020 Policy Rule, as well as identify and propose appropriate changes to NSPS OOOOa to resolve any discrepancies in the regulatory text between the 2016 NSPS and 2020 Technical Rule. These revisions are specific to the discrepancies in NSPS OOOOa created by the CRA resolution

2.3 Overview of Revisions under Consideration

Through Agency review and stakeholder input, a broad range of program improvements have been suggested. From these EPA identified those which could only be addressed through regulation change, and further limited to those which would provide the most protective impact. The following is a listing of regulatory revisions for NSPS OOOOb currently being considered and evaluated by EPA and is not final at this time.

- Work practice standards for monitoring and repair of fugitive emissions from well sites, compressor stations, and natural gas processing plants;
- Emission standards for centrifugal compressors;
- Work practices for reciprocating compressors;
- Emission standards for pneumatic controllers;
- Emission standards for pneumatic pumps;
- Emission standards for storage vessels;
- Work practices for completions of hydraulically fractured oil and gas wells; and
- Work practices for liquids unloading operations.

2.4 Related Federal Rules

There are two National Emission Standards for Hazardous Air Pollutants (NESHAP) rules that apply to certain equipment and processes in the oil and natural gas sector. These rules, listed below, address air toxics, primarily benzene, toluene, ethylbenzene, and xylenes (collectively referred to as BTEX) and n-hexane. These two rules were promulgated under section 112 of the Clean Air Act and are codified in 40 CFR Part 63 Subpart HH and Subpart HHH.

Aside from the EPA, several other Federal agencies have jurisdiction over the oil and natural gas sector.

- The Bureau of Land Management (BLM) within the Department of the Interior regulates the extraction of oil and gas from federal lands. BLM manages the Federal government's onshore subsurface mineral estate, about 700 million acres. BLM also oversees oil and gas operations on many Tribal leases and maintains an oil and gas leasing program. BLM does not directly regulate emissions for the purposes of air quality, but does regulate venting and flaring of natural gas for the purposes of preventing waste. An operator may also be required to control/mitigate emissions as a condition of approval on a drilling permit.
- The Bureau of Ocean Energy Management (BOEM) within the Department of the Interior manages the development of America's offshore energy and mineral resources. BOEM has air quality jurisdiction in the Gulf of Mexico and the North Slope Borough of Alaska and in federal waters on the Outer Continental Shelf 3-9 miles offshore.

- The Pipeline and Hazardous Materials Safety Administration (PHMSA) within the Department of Transportation ensures safety in the design, construction, operation, maintenance, and spill response planning of America's 2.8 million miles of natural gas and hazardous liquid transportation pipelines. This includes data and risk analysis, outreach, research and development, regulations and standards, training, inspections and enforcement and accident investigations. Section 113 of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (PIPES Act of 2020) mandates that PHMSA promulgate a final rule concerning gas pipeline leak detection and repair programs no later than one year after the enactment of the law.
- The Federal Energy Regulatory Commission (FERC) within the Department of Energy regulates natural gas pipeline, storage, and liquefied natural gas facility construction. FERC also issues environmental assessments or draft and final environmental impact statement for comment on most projects.
- The Internal Revenue Service (IRS), in the Internal Revenue Code (IRC), defines a stripper well property as "a property where the average daily production of domestic crude oil and gas produced from the wells on the property during a calendar year divided by the number of such wells is 15 barrel equivalents or less". See IRC 613A(c)(6)(E).

3 APPLICABLE SMALL ENTITY DEFINITIONS

The Regulatory Flexibility Act (RFA) defines small entities as including "small businesses," "small governments," and "small organizations" (5 USC 601). The regulatory revisions being considered by EPA for this rulemaking are expected to affect a variety of small businesses, but would not affect any small governments or small organizations. The RFA references the definition of "small business" found in the Small Business Act, which authorizes the Small Business Administration to further define "small business" by regulation. The SBA definitions of small business by size standards using the North American Industry Classification System (NAICS) can be found at 13 CFR 121.201.

The detailed listing of SBA definitions of small business for affected industries or sectors, by NAICS code, is included in Table 1, below. To estimate the number of small entities potentially impacted by the rule, EPA developed a list of operators of oil and natural gas wells and natural gas processing plants based on data from Enverus (wells) and the U.S. Energy Information Administration (processing plants); data on operators of compressor stations was not available at the time of the analysis. The list of well operators consists of all operators of wells completed in 2019, which serves as an approximation of the universe of operators that might be affected in future years by updates to the NSPS. The list of processing plant operators consists of all operators of natural gas processing plants in the EIA dataset for 2017 (the most recent year available). [1] The dataset does not have information on construction dates of plants, so a representative subset of operators of recently constructed plants could not be created as it was for wells. In total, the operator dataset consists of 1,947 unique operator names.[2]

Using an approximate string matching algorithm, EPA merged the list of operators with business information from D&B Hoovers to obtain information on NAICS codes (both own and ultimate parent), number of employees, and annual revenues. The algorithm matched 1,267 (65%) of the operators to NAICS codes with a valid SBA size classification threshold. Each matched operator was coded as small business (1,096 operators), not small business (162), or unknown (9) by comparing the estimated employee counts and annual revenues from Hoovers with the SBA size classification thresholds; unknown entities were missing the applicable employee count or annual revenue estimates. The results of the small business coding exercise are displayed by NAICS code in Table 1.

[1] https://www.eia.gov/naturalgas/ngqs/#?report=RP9&year1=2017&year2=2017&company=Name

[2] This does not necessarily mean that it represents 1,947 unique operators, however, as duplicates were only removed for exact string matches. For example, Oil and Gas LLC and Oil & Gas LLC would be represented as two unique entities.

Table 1: Industry Sectors, Definitions & Estimated Percentage of Small Entities Potentially Affected by EPA's Planned Action

Name of Industry/Sector	2017 NAICS Code	SBA Size Standard for Small Business	Number of Firms Identified	Estimated Number of Small Entities	Estimated Percentage of Small Entities for Identified Firms
Crude Petroleum	211120	1,250 employees	346	322	93%
Natural Gas Extraction	211130	1,250 employees	5	5	100%
Drilling Oil and Gas Wells	213111	1,000 employees	60	58	97%
Support Activities for Oil and Gas Operations	213112	$41.5 million in receipts	373	326	87%
Pipeline Transportation of Natural Gas	486210	$30.0 million in receipts	33	11	33%
Other	Many	Varies	431	373	87%

4 LIST OF SMALL ENTITY REPRESENTATIVES

EPA consulted with Advocacy to develop the list of small entity representatives (SERs) in Table 2. EPA issued a press release inviting self-nominations by affected small entities to serve as potential SERs. The press release directed interested small entities to a web page where they could indicate their interest in serving as a SER. EPA launched the website May 25, 2021 and accepted self-nominations until June 4, 2021. In addition, EPA supplemented the self-nominations by contacting the full list of SERs that participated in the 2015 SBAR Panel for this sector and inviting them to participate in this Panel. We also reached out to small business stakeholders during a training webinar on May 25, 2021 and invited them to participate in the Panel. EPA sent Advocacy a Formal Notification with the suggested list of potential SERs on July 2, 2021 and Advocacy responded on July 15, 2021. After the conclusion of EPA's Pre-Panel Outreach meeting with potential SERs, and after clarification of the likely scope of EPA's proposal, the Panel agreed that several small entities were not likely to be regulated and so were not invited to consult with the Panel as SERs.

Table 2: List of Potential Small Entity Representatives

Name	Affiliation(s)
Arthur Stewart	Cameron Energy Company (PA) Pennsylvania Grade Crude Oil Coalition (PGCC)
Douglas Jones	Catalyst Energy, Inc. (PA)
Charles E. Venditti	CountryMark Cooperative Holding Corp Indiana Oil & Gas Association (IOGA) Kentucky Oil & Gas Association (KOGA)
Rudy Vogt	Cumberland Valley Resources, LLC
J. Scott Huber	Fore Energy Partners, Inc (FEPI) Michigan Oil & Gas Association (MOGA)
James D. Elliott	Gas and Oil Association of West Virginia (GO-WV)
Lee Fuller	Independent Petroleum Association of America (IPAA)
Howard R. Dieter and Chuck Cornell	Jonah Energy, LLC
Edward Cross	Kansas Independent Oil & Gas Association (KIOGA)
Eric Johnson	Michigan Oil & Gas Association (MOGA)
Luke Miller	Miller Energy Company, LLC Summit Petroleum Company, LLC

Doug Mehan and Domenic Tedesco	PennEnergy Resources, LLC
Angie Burckhalter	Petroleum Alliance of Oklahoma (PAO)
Jason Modglin	Texas Alliance of Energy Producers
Ed Longanecker	Texas Independent Producers and Royalty Owners Association (TIPRO)
Dave Weinert	Wesco Operating, Inc
Tripp Parks	Western Energy Alliance (WEA)

5 SUMMARY OF SMALL ENTITY OUTREACH

EPA Office of Air Quality Planning and Standards (OAQPS) staff participates in monthly calls with Small Business Environmental Assistance Program (SBEAP) representatives. In April 2021, OAQPS provided an update to SBEAP representatives on EO 13990 and its direction to EPA to consider proposing a revised NSPS and standards for existing sources in the oil and natural gas sector by September 2021. In May 2021, EPA provided three days of training webinars for the public, with one of those days targeting small business stakeholders, to provide an overview of the industry and share information to help stakeholders effectively engage in the regulatory process. In June 2021, EPA held three days of public listening sessions where the public had an opportunity to provide their views on the oil and natural gas industry and EPA's upcoming proposed rule.

5.1 Pre-panel outreach meeting

EPA conducted a meeting/teleconference with potential SERs on June 29, 2021. To help SERs prepare for the meeting/teleconference, on June 22, 2021, EPA sent materials to each of the potential SERs via email. A list of the materials shared with the potential SERs during the pre-Panel outreach meeting is contained in Appendix A. For the June 29, 2021 pre-Panel outreach meeting with the potential SERs, EPA also invited representatives from the Office of Advocacy of the Small Business Administration and the Office of Information and Regulatory Affairs within the Office of Management and Budget. A total of 22 potential SERs participated in the meeting. EPA presented an overview of the SBAR Panel process, an explanation of the planned rulemaking, and technical background.

This outreach meeting was held to solicit feedback from the potential SERs on their suggestions for the upcoming rulemaking. EPA asked the potential SERs to provide written comments by

July 13, 2021. Comments raised during the June 29, 2021 outreach meeting and written comments submitted by the potential SERS are summarized in section 6 of this document.

5.2 Panel outreach meetings

The Panel conducted an outreach meeting/teleconference with the SERs on July 29, 2021, with a follow up on August 3, 2021. To help SERs prepare for these meetings, EPA sent materials to each of the SERs via email. A list of the materials shared with the SERs during the Panel outreach meeting is contained in Appendix A. A total of 14 SERs participated in the meeting.

These outreach meetings were held to solicit feedback from the SERs on their suggestions for the upcoming rulemaking. EPA asked the SERs to provide written comments by August 12, 2021. Comments raised during the July 29, 2021 and August 3, 2021 outreach meetings and written comments submitted by the SERS are summarized in section 7 of this document.

6 SUMMARY OF PRE-PANEL COMMENTS FROM POTENTIAL SMALL ENTITY REPRESENTATIVES

At the conclusion of the Pre-Panel Outreach Meeting, potential SERs were asked to submit written questions and comments to EPA. Nine entities submitted written materials to EPA. The following subsections summarize these submissions.

6.1 Number and Types of Entities Affected

CountryMark, INOGA, and KOGA stated that the majority of wells in Indiana, Illinois, and Kentucky are produced by small businesses. There are more than 58 small business oil and gas operators represented by INOGA in Indiana and more than 98 small business oil and gas operators represented by KOGA in Kentucky.

CountryMark, INOGA, and KOGA stated that CountryMark operates 363 tank facilities, with less than 5 requiring combustion units. 24 are affected facilities under OOOOa.

Cumberland Valley Resources stated that from 2005 to 2010, they drilled approximately eight new oil or gas wells per year. From 2011 to 2015, they drilled two or three oil wells per year. They have not drilled a new oil well since 2015 and haven’t drilled a new gas well since 2010. In 2018, they divested their oil producing properties, but continue to operate approximately 60 gas wells.

Cumberland Valley Resources estimated there are many thousands of small operators in the Appalachian and Illinois Basins, over 1,000 in Kentucky.

KIOGA stated small businesses produce 92% of oil wells and 63% of gas wells in Kansas.

KIOGA stated that there are 750,000 low production wells in the United States, typically operated by small businesses.

KIOGA estimates that 90 wells are drilled or modified each year by some operators.

PGCC and Cameron Energy Company stated that there are over 100,000 conventional oil and gas wells in operation in Pennsylvania, almost all of which are low production wells. Most of these wells were drilled over 15 years ago.

6.2 Potential Reporting, Recordkeeping, and Compliance Requirements

6.2.1 Requirements

CountryMark, INOGA, and KOGA encouraged EPA to implement additional reductions to recordkeeping and reporting requirements where data collected does not further support the reduction in emissions.

KIOGA listed a number of existing reporting and recordkeeping requirements which they felt were burdensome and added no value. These requirements included notification of hydraulic fracturing, FLIR operator training, starting and ending time of monitoring surveys, maximum wind speed, and survey deviations.

PAO stated EPA should maintain the recordkeeping and reporting provided in the 2020 Technical Rule. Where compliance with state programs is deemed equivalent, no further recordkeeping or reporting should be required.

CountryMark, INOGA, and KOGA recommended one year compliance timeline for small businesses.

6.2.2 Costs

Cumberland Valley Resources stated operators of low production wells cannot afford to hire staff to fill out and keep the updated records that OOOOa requires.

KIOGA stated the OOOOa documentation burden grows as new wells and tank facilities are added to the program each year. KIOGA questioned the need for some of the data that OOOOa requires.

KIOGA estimated the cost to develop a management and reporting system is $40,000 - $50,000, with an ongoing annual cost of compliance of $20,000 - $100,000. KIOGA believes that one or more full time positions may be required to meet all the annual reporting and data management requirements, with annual salary and benefits of $50,000 - $60,000.

KIOGA estimated the burden of developing and maintaining a corporate-wide site specific monitoring plan is 500 hours to solicit input, develop the written program, review with the management team, and implement the program, with an associated cost of $30,000 - $50,000.

KIOGA estimates that storing digital photos and reports for 5 years will require the development of a data management system, purchasing of additional data storage systems, and training of 600 – 800 hours, with an associated cost of $40,000 - $50,000.

6.2.3 Electronic Reporting

Cumberland Valley Resources stated the electronic reporting template is daunting to small operators and very little of it is applicable to their operations.

PAO stated EPA should ensure the electronic reporting template does not call for additional information that is not otherwise required, and that assistance with electronic reporting would be beneficial to small businesses.

PAO stated EPA should consider the development of a fugitive emissions tracking software program to aid small businesses with compliance. Currently available software is an additional cost to small businesses.

6.3 Fugitive Emissions Requirements

6.3.1 Low production well sites

6.3.1.1 Applicability

Cumberland Valley Resources, CountryMark, INOGA, KOGA, PGCC and Cameron Energy Company stated low production wells should continue to be exempt from OOOOa's fugitive emissions requirements.

Cumberland Valley Resources stated low production wells should at least be considered a separate subcategory to allow operators to use simple, common sense solutions to periodically check for fugitive emissions in a manner that doesn't require additional personnel or equipment.

CountryMark, INOGA, and KOGA stated low production wells should be their own subcategory in any future regulation because of their de-minimis emissions profile. Most low production wells are operated by small businesses.

PAO stated EPA should consider an offramp to reduce costs on small businesses. For example, after two OGI surveys with no leaks, monitoring could decrease to annually or every 2 years. EPA should also allow for exemptions or reduced inspections based on the API gravity of the crude oil.

CountryMark, INOGA, and KOGA recommended retaining the low production well exemption, updated to 12 month rolling average of production, rather than initial production.

6.3.1.2 Emissions Profile

KIOGA, Cumberland Valley Resources, CountryMark, INOGA, KOGA, PAO, and the Texas Alliance of Energy Producers recommended a DOE study of emissions from low production wells that should be completed in 2021. Preliminary results from the DOE third-party methane emission study indicate no quantifiable or measurable emissions from wells or tank facilities. EPA should use the emissions profile information developed in this study to design a low production well program, and focus its program to address key sources.

PAO stated EPA must understand the emissions profile of low production wells to determine if regulations are needed and to develop an appropriate regulatory program.

KIOGA stated that EPA does not have enough data to appropriately regulate low production wells. KIOGA stated that EPA has relied on specious studies by environmentalists, outdated studies that were never designed for regulation, and studies that assessed very few wells. KIOGA stated that the studies EPA has relied upon were based on emissions data collected without an understanding of the activities on the site. For example, without knowledge of whether the emissions were fugitive emissions or rather a permitted release when a tank was being filled. Sampling was generally ten minutes to an hour, but the studies extrapolated these values to daily and annual rates. KIOGA further stated that these studies imply that most emissions from low production well sites are from storage vessels, and managing storage vessel emissions does not require a complex LDAR program.

Cumberland Valley Resources stated that gas gathering systems in Kentucky are constructed using plastic pipeline less than 25 psi. Low production well wellheads include small numbers of brass and steel fittings and valves threaded together (dozens of 2" components compared to hundreds of larger components like used on high volume/high pressure wells). Threaded connections in the low pressure piping, when doped and tightened properly, very seldom leak. Any leaks at these connections can be detected using soap bubbles.

6.3.1.3 Requirements

Cumberland Valley Resources, CountryMark, INOGA, and KOGA stated requirements for low production wells are not warranted or justified. Operators of these wells cannot bear the additional cost of fugitive emissions monitoring, even at the annual frequency.

Cumberland Valley Resources stated that once a well becomes a low production well, a less expensive fugitive emissions program may extend the economic lifetime of a well.

KIOGA stated that the regulatory structure applied to low production wells is significant because their viability depends on their cost of operation.

KIOGA and Cumberland Valley Resources stated the 2016 NSPS fugitive emissions program was designed for large, high-production facilities and should not be applied to low production well sites.

CountryMark, INOGA, and KOGA recommended annual OVA and soap bubble tests for leaks at low production wells and associated tank facilities.

PAO stated EPA should allow alternative monitoring, for example functional testing of onsite equipment or AVO.

KIOGA, CountryMark, INOGA, and KOGA asked EPA to change the requirements for all facilities owned by small businesses to use OVA inspections or soap bubble tests to detect leaks. Implementing this change will significantly reduce costs of compliance as well as documentation and reporting costs for small business entities. They estimated that the inspection cost may be reduced by as much as 50% by permitting OVA and soap bubble testing at tank facilities associated with low production well sites. The cost savings will come through our trained employees performing the inspections during already scheduled daily or weekly inspections of the facilities. Independent contractors with expensive OGI equipment and certifications will not need to be scheduled, paid for their travel time and time on location, managed as they are on our work sites, and develop reports for our staff to review and address deficiencies. This compromise in inspection technique will not result in a measurable increase in emissions because tank emissions are already less than 6 tpy, indicating that the potential to emit is already low enough to not be able to reliably support a combustion system.

6.3.2 Tank batteries

Cumberland Valley Resources, CountryMark, INOGA, and KOGA stated that tank batteries under the 6 tpy threshold may fall into the fugitive emissions program. These tank batteries are uncontrolled and a fugitive emissions program would be burdensome and have no environmental benefit.

6.3.3 Leak Rate

CountryMark, INOGA, and KOGA stated that during CountryMark's 4 years of compliance with OOOOa, they had the following leak rates:

Year	# of Leaks	Components Inspected	Failure Rate
2020	6	4,815	0.1%
2019	14	3,700	0.4%
2018	9	2,925	0.3%
2017	9	1,195	0.8%

CountryMark, INOGA, and KOGA stated that leaks are generally challenging to detect with OGI because of low production rates, low wellhead pressure, and low Gas to Oil ratio in the Illinois Basin.

KIOGA stated that leak rates are between 1.1 – 1.65%, far lower than the EDF study's 2.3-60%. KIOGA stated that the EDF had questionable methodology and poor data quality. The EDF study relied on remote sensing of emissions and not the bottom-up onsite measurements recommended by the National Academy of Sciences, meaning the study could not differentiate between fugitive losses and permitted emissions.

6.3.4 Costs

CountryMark, INOGA, and KOGA estimated the annual cost to complete OGI monitoring of well sites and tank batteries is $75,000. This cost includes amortizing an OGI camera, training an employee and vehicle cost, insurance cost, and documentation and reporting costs.

MOGA stated the first year cost estimates would likely range from $4,000 - $10,000 for initial implementation. Many small businesses in Michigan would likely need to hire a third-party consultant to oversee implementation of these regulations. This cost estimate is based on the need to gather, transfer, and educate personnel to facilitate the necessary in-depth understanding of each of the 22 well sites in EPA's model plant. The variability of these costs can be allocated to specific training, equipment and software purchases and functional knowledge and ability to correctly implement proposed regulation requirements.

MOGA estimates the annual cost per well site to be between $3,000 and $6,000 because of the need to hire third-party consultants, rather than in-house staff. In addition, the EPA did not consider initial surveys for a single well that was new, modified, or reconstructed outside of normally scheduled monitoring efforts. Single well monitoring using LDAR can range from $2,500 to $3,500. The EPA further assumed fixed production and a constant number of wells, when in reality, the number of producing wells can vary due to seasonal restrictions, formation dynamics, operational agenda, oil and gas prices, and contracts.

MOGA estimates the annual repair cost for a single repair, including parts, for a small leak of less than 1 scf/day would be between $500 - $1,500. In many cases, the repairs are conducted by third party contractors.

MOGA recommends that EPA provide cost considerations for both in-house and third-party contractors.

6.3.5 Emerging Technology

PAO stated that the EPA should ensure that there is an avenue to allow for new and emerging control and monitoring technologies. For example, multiple well inspections could be done each day using drone / fixed wing technologies versus traditional OGI. These technologies must be cost effective, reliable, easy to install and maintain.

6.4 Well Completion Requirements

6.4.1 Costs

KIOGA stated that certified combustion devices that will meet gas flow rate requirements and gas quality will cost $12,000 - $22,000 to purchase and another $8,000 to install. A conventional oil well may cost $300,000 - $600,000 to drill and complete. Installation of a combustion system could be 5-10% to the total cost of the project. This does not include the cost to purchase and install a separator, install piping, complete the required surveys, and recordkeeping and reporting costs. These additional costs of compliance will eliminate projects from being implemented.

6.4.2 Definitions

KIOGA, CountryMark, INOGA, and KOGA recommended amending the definition of hydraulic fracturing to explicitly exclude conventional wells. KIOGA believes that many wells in Kansas don't meet this definition because their processes don't penetrate tight formations or require high rate, extended flowback.

6.5 Storage Vessel Requirements

6.5.1 Requirements

MOGA provided an example of a small business in Michigan who had to purchase and install a propane tank to keep the pilot light burning on its control device for storage vessel emissions due to significant production decline from the well. This and other OOOOa compliance costs led the producer to plug the well even though the well would likely produce at a marginal status for many more years.

PAO stated many sites may not have electricity needed to power compressors for tank vapor recovery, and low production wells may not produce enough gas to power the unit.

PAO stated OOOOa control requirements for all tanks may result in higher emissions because of the combustion processes as compared to allowing uncontrolled tank emissions.

6.5.2 Maximum Daily Throughput

PAO stated the method for calculating maximum daily throughput is unnecessarily burdensome, especially for low production wells and facilities connected to pipelines with a mix of trucked and pipeline shipped liquids. Compliance requires tank-specific metering or intensive daily operating recordkeeping since tank gauging alone does not account for liquids sent through a lease automatic custody transfer unit.

6.6 Costs and Impacts Analysis

KIOGA stated that EPA often underestimates the cost of compliance and overestimates the benefits provided by regulations.

KIOGA stated that small oil and gas compliances in Kansas have experienced the following costs of compliance with OOOOa:

Activity	Cost	Frequency
VOC inspection of tank facility	\$500 - \$2,000	2x per year per facility/well
Documentation and record keeping	\$20,000 - \$100,000	Annually
Green Completion (only for non-delineation wells)	\$10,000 - \$15,000	Every new exploration well
Install sample fittings (parts and labor) for gas samples	\$500 - \$1,000	Every new facility
Laboratory analysis	\$500 - \$1,000	Every new facility
Engineering evaluation of lab data analysis	\$250 - \$500	Every new facility
PE Certification of combustion system	\$2,500 - \$3,000	Every new facility
Installation of combustion system	\$20,000 - \$40,000	Every new facility
Monthly inspection of combustion system	\$250 - \$500	Monthly
Monthly inspection after removal of combustion system	\$2,500 - 4,000	Monthly
Design of combustion system	\$10,000 - \$15,000	One time cost
Develop record keeping system	\$40,000 - \$50,000	One time cost
Develop site specific monitoring plans	\$30,000 - \$50,000	One time cost
Purchase FLIR camera	\$95,000 - \$100,000	One time cost
FLIR camera training	\$3,000 - \$5,000	One time cost
Purchase sample collection equipment	\$2,000 - \$5,000	One time cost

Table 2. Compliance Activities and Costs Required by NSPS OOOOa

Texas Alliance of Energy Producers stated that their actual costs may be higher than EPA's estimates because the internal operations to adapt and conduct new regulatory requirements has been limited due to the contraction of the industry in 2020.

MOGA and FEPI stated the overall cost of regulation may cause producers to plug and abandon marginal wells in Michigan before the end of their lifetime because they are no longer economically productive. PGCC and Cameron Energy Company stated drilling conventional wells in Pennsylvania is no longer economical.

The Petroleum Alliance of Oklahoma stated EPA should provide details on how the social cost of greenhouse gas analysis will impact small businesses.

6.7 Need for Regulation

6.7.1 Scope of methane emissions

KIOGA stated that Oil and Natural Gas systems account for about 1.2% of the US Green House Gases Inventory (GHGI). Low production wells account for about 10-11% of U.S. production. Their emissions would be in the 0.10-0.20% range of the GHGI.

6.7.2 Voluntary programs

KIOGA stated that a number of natural gas producers have voluntarily replaced, fixed, or removed 31,000 high-bleed pneumatic controllers on their equipment.

6.8 Other Comments

CountryMark, INOGA, and KOGA stated that OOOOa requires propane to maintain a pilot light for combustion systems, and for low production well sites, more propane is consumed than gas is burned at the flare. They recommended that for low production wells, the operator should determine if propane is required to support flare systems based on safety requirements, rather than one size fits all regulations. CountryMark, INOGA, and KOGA also stated that this requirement has contributed to propane shortages through the United States.

PAO encouraged EPA to allow in-house engineers certify closed vent system design. These calculations may be completed in-house with the same simulation software that a consulting firm with a Professional Engineer would use.

The American Public Gas Association, City Of Las Cruces Utilities/Gas, Middle Tennessee Natural Gas Utility District, Pensacola Energy, and Unitil Corporation stated that if EPA is not considering any changes to the 2016 final rule exemption of natural gas utility intra-state distribution, transmission pipeline, storage or LNG peak shaving operations inside and including the local distribution utility custody transfer station, then our gas utility operations would not be affected. If EPA is not considering changing the 2016 final rule's requirements for interstate natural gas transmission pipelines, then Unitil's interstate natural gas transmission pipeline operations would not be affected. However, if EPA does plan to consider any such changes, then we will need an opportunity to provide information about how those proposals could impact our small entity operations.

7 SUMMARY OF PANEL COMMENTS FROM SMALL ENTITY REPRESENTATIVES

At the conclusion of the Panel Outreach Meeting, SERs were asked to submit written questions and comments to EPA. Nine entities submitted written materials to EPA. The following subsections summarize these submissions.

7.1 Rulemaking Scope

Many SERs stated that conventional vertical wells should be exempt from NSPS OOOOa, even if they have been hydraulically fractured.

Catalyst Energy stated that conventional wells in Pennsylvania and much of the Appalachian Basin have largely been hydraulically fractured since the 1960s. A conventional oil well will have a small footprint during drilling and hydraulically fracturing operations – typically 5,000 square feet, while an unconventional horizontal well will have a footprint over 20,000 square feet. An unconventional well undergoing hydraulic fracturing will pump millions of gallons of water and chemicals, while a conventional hydraulic fracturing operation will use 100,000 to 200,000 gallons of water with little to no chemicals, with much of the water being recycled. Hydraulic fracturing at conventional wells has little flowback with nearly no natural gas released.

TIPRO, IPAA, and GO-WV stated that EPA's definition is not appropriate because both conventional and unconventional wells engage in hydraulic fracturing. Conventional wells do not penetrate and produce from tight formations, such as shale or coal formations, and do not require high rate, extended flowback. Most conventional wells, being shorter, and having a shorter profile in producing strata, produce methane at lower rates than horizontal, nonconventional wells.

TIPRO, IPAA, and GO-WV stated that hydraulic fracturing of conventional wells involves thousands of gallons of water, compared to millions of gallons used for unconventional wells, and flowback is in hours, versus weeks or months. The permeability of the rock formations where conventional wells are drilled is statistically different compared to unconventional wells.

PAO stated that conventional wells are typically vertical, and the completion of a vertical well is much less involved than a horizontal well. Completion lasts less than a day, compared to many days or weeks for a horizontal well. The clean-up and drill out is also much less involved, both for completions and recompletions. Completing a vertical well generates less emissions compared to horizontal wells.

PGCC and Cameron Energy stated that a conventional wells should be treated differently than unconventional wells. A conventional well has a 35 times smaller footprint than an unconventional well. Wellhead pressures of conventional wells are only several hundred pounds versus thousands of pounds. The substantially greater pressures and items of infrastructure associated with unconventional wells means they have a greater potential for fugitive emissions. Conventional wells also have a much lower equipment and fugitive component count than unconventional wells. The typical conventional oil well site would not normally include glycol dehydrators, amine gas sweetening units, line heater, heater treaters, reboilers, gas compressors, pneumatic controllers, pneumatic pumps, or pipeline blowdowns.

PGCC and Cameron Energy stated that EPA could distinguish between large and small hydrofractures based on fluid volume, pumping pressures, shut-in pressures, permeability of fractured formations, and flowback rates and times.

Cumberland Valley Resources, LLC stated that they operate conventional, low volume, low pressure wells, that have a different profile than unconventional wells based on scale, water usage, and pressure, regardless of fracking status. No separator is needed during flowback for these wells. Only after the majority of the frack fluid is removed will any significant amount of gas or oil be present.

7.2 Potential Reporting, Recordkeeping, and Compliance Requirements

WEA, TIPRO, IPAA, and GO-WV stated the streamlining of recordkeeping and reporting requirements in the 2020 Technical Rule was successful and EPA should not abandon these changes in a new rule.

TIPRO, IPAA, and GO-WV stated that if EPA deems a state program equivalent to OOOOa, no additional recordkeeping or reporting beyond the state's requirements should be required.

MOGA and FEPI stated EPA should remove annual reporting requirements, and require small businesses to retain records for 5 years, removing the exorbitant cost of annual reporting that may never be reviewed.

CountryMark, INOGA, and KOGA requested that small entities have longer than 60 days to comply with the regulation.

CountryMark, INOGA, and KOGA recommended removing well completion reporting requirements. They recommend EPA only collect data to inform decision making, rather than compliance assurance.

Cumberland Valley Resources, LLC stated EPA needs to identify and adopt simplified and cheaper methods of emissions reductions. Current compliance costs impact the economic viability of legacy wells.

WEA stated that the CEDRI template was a success and the benefits of electronic reporting should be brought forward into the 2021 proposal.

CountryMark, INOGA, and KOGA stated that EPA amend its electronic reporting template to report for existing and new sources on separate sheets. Only the necessary information from annual monitoring should be entered for wells that are newly affected facilities, reducing the volume of data for operators to input each year.

7.3 Fugitive Emissions Requirements

7.3.1 Requirements

WEA supported the use of aerial, satellite, and other forms of monitoring for fugitive emissions requirements beyond traditional LDAR, but only as an alternative and not as an additional requirement. This technology can be quite costly depending on the range of operations, pipeline right-of-way mileage, mobilization f71s for aircraft, and even terrain impacts. In addition, fixed-wing flyovers often require follow up with a ground-based infrared camera in order to ground truth any identified leaks or abnormal emissions to verify if the source is a persistent or a transitory, short-lived event.

WEA stated that EPA should provide relief from monitoring requirements in exchange for demonstrations that site-wide emissions are lower than a certain threshold. First, this would encourage the adoption of new technology. Second, it could lower emissions associated with traveling to facilities on increased monitoring frequencies, especially for those facilities that could otherwise be demonstrated to be low emitting.

The Texas Alliance of Energy Producers stated that there was not sufficient workforce available to complete fugitive surveys.

MOGA and FEPI stated that initial monitoring should be allowed within the first 60 days or during the next applicable monitoring period. This allowance would reduce monitoring costs while efficiently distributing monitoring costs across multiple well sites.

CountryMark, INOGA, and KOGA stated that identifying all fugitive emissions components and developing a site map with an observation path is expensive and time consuming.

CountryMark, INOGA, and KOGA supported allowing the use of AVO and soap bubbles as a leak detection method.

CountryMark, INOGA, and KOGA stated EPA should allow emerging technologies such as infrared cameras that attach to smart phones.

7.3.2 Low production well sites

MOGA, FEPI, and Cumberland Valley Resources, LLC stated that AVO surveys should be allowed instead of traditional LDAR for low production well sites.

Catalyst Energy stated that new oil wells are often stripper wells from the onset. Most legacy wells produce only a few gallons per day, and well head pressures are kept as low as possible to maintain flow of oil. These wells have very little leakage of methane and VOC emissions.

CountryMark, INOGA, KOGA, TIPRO, IPAA, GO-WV, and Cumberland Valley Resources, LLC stated that low production wells should be exempt from the NSPS. CountryMark, INOGA, and KOGA stated that this should be based on a 12 month average production rate.

TIPRO, IPAA, and GO-WV stated that EPA has no data, or incorrect data on emissions from low production wells. They stated that the studies from environmental non-governmental organizations are flawed and should not be relied upon for regulatory purposes.

The Texas Alliance of Energy Producers, TIPRO, IPAA, GO-WV, MOGA, FEPI, CountryMark, INOGA, KOGA, PAO, and PGCC and Cameron Energy stated that the Department of Energy has initiated a study to quantify emissions from low production and marginal wells, and results are due in 2021. They stated that the EPA should wait for the completion of this study before issuing a proposal.

TIPRO, IPAA, and GO-WV stated that EPA should focus on super emitters / fat-tail emissions. The DOE study indicates that the majority of emissions from low production wells is from relatively few sources, for example, the top 10% of emission sources in the Appalachian Basin contributed 72% of total measured emissions, and the top two emissions sources accounted for 40%. These sources harm the environment and threaten the economic viability of many small businesses.

TIPRO, IPAA, and GO-WV stated that low production wells should be subcategorized because they have a much lower potential to emit than other wells. They stated that emissions at low production wells are dependent on volumetric flow, pressure, and component count.

MOGA and FEPI stated that low production wells should be subcategorized, and EPA should update its definition to align with the IRS Tax Code.

MOGA, FEPI and PAO stated that EPA should create an offramp for low production and marginal wells. These wells cannot adsorb the costs of maintaining an LDAR program, including the costs of surveys, data capture and collection, reporting and repair.

PGCC and Cameron Energy stated that EPA should use a threshold of 10 barrels per day for low production wells.

7.3.3 Leak Rate

PGCC and Cameron Energy stated that a random study of wells in New York was conducted in 2021, and they found out of 150 conventional gas well sites, 22 leaking components were found, or 0.11% of all components monitored using OGI.

7.3.4 Costs and Impacts

WEA stated that some aerial survey vendors charge on a per facility basis while others have a fee based on the size of the actual basin. Companies have seen costs ranging from $50,000 to $240,000 to complete a single fixed-wing methane survey of a primary asset area (typically including all facilities in a given basin). Other cost estimates to cover an entire field are $125,00 for 1,000 square miles. On a per-facility basis, these costs would range from $110 and $176 for an individual facility based on the frequency of aerial surveys.

WEA stated that multi-client campaigns where companies would share in mobilization costs would be more efficient in fields where multiple operators are in the same basin. This would be critical for smaller operators as funding an individual-operator aerial survey would be quite costly and inefficient.

The Texas Alliance of Energy Producers stated that EPA' estimated cost of OGI monitoring is low. They stated that they lacked the adequate staff and resources to meet this new requirements, and could make some of their leases uneconomical. They stated that this would be cost prohibitive for low volume wells.

MOGA and FEPI stated that a single day of OGI monitoring costs $2,500 to $3,500, with a significant portion of the cost due to mobilization.

MOGA and FEPI stated that EPA's model plant over-estimates the average number of wells that can share implementation and ongoing annual regulation costs.

MOGA and FEPI stated that the first year costs of the NSPS would likely range from $4,000 to $10,000. This includes that cost of a third party consultant, and could vary based on specific training, equipment, software purchases, and functional knowledge to implement the regulation.

MOGA and FEPI estimated that the ongoing annual cost per well site ranges from $3,000 to $6,000. EPA did not consider initial surveys for stand alone well sites outside the normal schedule, and LDAR monitoring can range from $2,500 to $3,500 per site. EPA also assumes fixed production and a constant number of wells; MOGA and FEPI suggested EPPA base its assumptions on actual production and operational dynamics, which vary based on season, formation dynamics, operational agendas, oil and gas prices, and landowner contracts. MOGA and FEPI stated that a single repair would likely cost between $500 and $1,500.

MOGA and FEPI stated that EPA should provide cost estimates for both in-house and third party contractors.

CountryMark, INOGA, and KOGA stated that developing a written compliance program is a one time cost of $5,000 to $10,000. Creating site plans takes an estimated 4 hours per well site at $125 per hour.

7.3.5 Exemptions

TIPRO, IPAA, and GO-WV stated that EPA should reevaluate the wellhead only exemption to allow a drop-tank or separator at the well site. This is often necessary for safety and operational considerations, and has minimal emissions.

PGCC and Cameron Energy stated that EPA could categorize wells by well bore direction, and exempt vertical wells.

7.4 Storage Vessel Requirements

7.4.1 Emissions

Catalyst Energy, Inc. stated that centralized tank batteries service 20-40 wells, and most have separators to conserve and produce what little gas there is. Little gas is evolved from the oil in those tanks. A pressurize hatch holding pressure on the tank should be sufficient since off gassing is very low on older wells.

PGCC and Cameron Energy stated control of emissions at conventional tank batteries is affected by tank composition, cost of oxygen monitoring, availability of gas sales pipeline, intermittent gas generation, and difficulty of powering the control infrastructure.

7.4.2 Applicability

WEA stated applicability should continue to be based on VOC emissions. VOCs are a close proxy for methane emissions, and changing the applicability would cause operators of facilities dating back to 2011 to develop new applicability determinations, resulting in cost and waste with no environmental benefits. This change may impact operators data management, recordkeeping, and monitoring requirements.

WEA stated applicability should continue to be based on single storage vessels, rather than a tank battery. Since this requirement has been in place since 2011, it would be prudent to keep the current applicability.

PGCC and Cameron Energy stated that operators may not drill new wells or may install a new storage vessel or tank battery in order to stay below the 6 tpy threshold.

CountryMark, INOGA, and KOGA stated that EPA should allow operators to calculate applicability based on volume of produced oil instead of other more rigorous methods.

7.4.3 Requirements

WEA stated that EPA should provide an off ramp or an alternative applicability options for tanks that are part of a larger battery. They recommended a threshold at 24 tpy of VOC (for a typical facility of 4 tanks, each at 6 tpy), and allow those facilities to not be affected facilities or set a lower threshold as an off ramp for low producing facilities. This could avoid needing to calculate or assign emissions to individual tanks without changing the current applicability threshold.

PAO stated that using a methane-based applicability would cause small operators to conduct costly retrofits to install flares or control devices due to methane emissions. In some cases, there may not be sufficient volumes of tank vapors to route to a control device.

CountryMark, INOGA, and KOGA stated that the EPA should provide an offramp to storage vessels that fall below 6 tpy. No compliance activities should be associated with these vessels.

7.5 Compressor Requirements

WEA stated Colorado's definition of a centralized production facility would apply to a site that only had a single wellhead and a compressor. As a result, this definition is essentially meaningless, as it would apply to functionally all production facilities. The 2021 proposal should maintain the same applicability currently delineated by OOOOa.

PAO stated that compressors at well sites are a very small emissions source, and most vendors replace the rod packing every 36 months as part of their maintenance programs, so this would result in minimal emissions reductions.

PAO stated the requirement to track records of replacement or tracking flow measurement may be unnecessarily burdensome and costly. PAO stated basing rod packing changeout using emissions monitoring rather than hours may be beneficial for large operators, but create additional burden for smaller operators. PAO recommended that EPA include this as an option or alternative to tracking hours.

PGCC and Cameron Energy stated that the NSPS incentivizes operators to run old or oversized compressors in order to avoid triggering the NSPS requirements.

Cumberland Valley Resources, LLC stated that removing the wellsite exemption for compressor requirements could prevent a small operator from developing new gas fields.

Cumberland Valley Resources, LLC stated field or small central production facilities using less than 250 horsepower should be exempt, or at least have simplified requirements and rod packing requirements extended to 60 months.

7.6 Pneumatic Controller Requirements

PAO stated that zero emissions controllers would not be feasible at sites where electricity is unavailable or insufficient. The installation of gas fired compressors at those sites to supply air for instrument air systems may defeat the purpose by ultimately increasing emissions, and the installation of electric service would be extremely expensive.

PAO provided a 2014 survey of emissions from pneumatic controllers from production sites in Oklahoma, conducted by the Oklahoma Independent Petroleum Association. Existing emission factors overestimate pneumatic controller emissions, and intermittent bleed pneumatics generate minimal emissions. EPA should consider if expanding pneumatic controller requirements is needed.

7.7 Liquids Unloading Requirements

Catalyst Energy, Inc. stated that liquids unloading takes many forms, from simply blowing a gas well down to a tank bailing an open hole to swabbing a cased hole to various types of artificial lift. These techniques depend on velocity up the casing or tubing to lift liquids effectively. Any techniques that impede velocity to recover gas would reduce the effectiveness of the operation and increase frequency of liquids unloading operations.

WEA stated that the EPA should employ a series of best management practices that align with those used by members of the Environmental Partnership[3], according to their protocol. The methodology has minimized emissions from 44,000 liquids unloading events, and is achievable, effective, and relatively inexpensive compared with other emission reduction techniques. Liquids unloading can be performed similarly to reduced emissions completions when there is not sufficient gas to operator a separator. The Environmental Partnership's protocol monitors the manual unloading process on-site and closes all wellhead vents to the atmosphere as soon as practicable. This minimizes emissions from the event without requiring the installation of use of specialized equipment.

TIPRO, IPAA, and GO-WV stated that liquid unloading practices are site-specific, and a one size fits all regulation is inappropriate. Releasing a certain amount of gas is inherent in the process, and capturing this gas has a considerable cost, and may be technically infeasible in

[3] https://theenvironmentalpartnership.org/

certain cases. TIPRO, IPAA, and GO-WV stated that nothing has changed since 2016 when EPA determined it did not have enough information to regulate this source.

PGCC and Cameron Energy stated that there is no technology currently in use in New York or Pennsylvania which would capture emissions during liquids unloading. Emissions from these events are low and might not warrant recovery or a flare. A vapor recovery system could work, but would require more energy and generate more emission than it captures.

Cumberland Valley Resources, LLC stated that swabbing is done using a small truck mounted rig that is moved over the wells when needed. Well construction often includes a string of tubing run to the bottom of the well in order to remove fluid build up over time by pumping or swabbing. Some wells have never been swabbed, and some need to be swabbed every couple of years. This is done in a matter of hours and the fluid removed is trucked off location. It would be almost impossible to flare and gas during this process due to the size and proximity to forested lands. Plunger systems don't work because they don't have enough volume or pressure.

7.8 Costs and Impacts Analysis

CountryMark, INOGA, KOGA, MOGA, FEPI, and Cumberland Valley Resources, Inc. stated that the additional cost of the NSPS may accelerate the plugging of wells. This will exacerbate the need to drill additional wells to meet consumer demand.

7.9 Other Comments

7.9.1 Professional Engineering Certification

MOGA and FEPI stated that the requirements for PE certification is insulting and can cost up to $10,000 per facility. They stated that this certification can be done by anyone with a mathematical, geological, or other related education combined with a fixed amount of experience in the design, operation, construction and maintenance of oil and natural gas facilities.

8 PANEL FINDINGS AND DISCUSSIONS

8.1 Number and Types of Entities Affected

EPA is currently working to determine small business concentrations for affected facilities in the proposed rule. Table 3 illustrates small business concentrations in a recent year based on operators of well sites and natural gas processing plants.

Table 3. Small Business Concentrations at Well Sites and Natural Gas Processing Plants

Category	Total firms	Small	Not small	Unknown	Small business percentage (of identified firms)
Well Sites	1,753	1,010	107	636	90%
Natural Gas Processing Plants	205	93	58	54	62%

8.2 Potential Reporting, Recordkeeping, and Compliance Requirements

The potential reporting, recordkeeping, and compliance requirements are still under development. SERs identified challenges small operators have had with the electronic reporting template and suggested additional efforts to ease compliance, particularly for small businesses. The Panel recommends that EPA assess ways to simplify the electronic reporting template for small businesses and offer small business consultation during the next update of the template.

The SERs also specifically wrote in favor of the recordkeeping and reporting streamlining in the 2020 Technical Rule. The Panel recommends the proposed rule not eliminate the streamlining provisions of the 2020 Technical Rule and propose to continue these provisions in the new NSPS OOOOb where appropriate.

SERs also recommended reviewing reporting requirements to ensure that the information provided to regulatory authorities is being used to target enforcement resources and ensure environmental benefits. SERs do not believe it necessary for regulatory authorities to gather detailed operational information to ensure compliance. SERs also want to ensure that where state compliance programs are considered equivalent to the NSPS, reporting and recordkeeping requirements are limited to what is required by the state program. The Panel recommends that reporting and recordkeeping requirements should be aligned to existing business practices to the extent possible.

Advocacy recommends that EPA reduce reporting requirements to only information necessary to target enforcement with the NSPS. EPA believes that reporting should include information to assure compliance as well as target enforcement.

Advocacy recommends that EPA adopt the state equivalency provisions of the 2020 Technical Rule for methane to the extent that existing state programs have the practical effect of regulating methane emissions as part of VOC emission controls. EPA recommends that the proposed revisions to NSPS OOOOa include state equivalency provisions for those states determined to be equivalent in the 2020 Technical Rule that regulate both VOC and methane. EPA recommends extending this equivalency determination to NSPS OOOOb for states that regulate both VOC and methane at a level equivalent to the new proposed NSPS.

8.3 Related Federal Rules

SERs expressed concerns about potentially overlapping federal regulations that could apply to this sector, particularly PHMSA's leak detection and repair rule, discussed in section 2.4. EPA acknowledges the SERs' concerns and notes that EPA and PHMSA staff meet regularly to discuss scope and boundaries of their respective rules. EPA understands that PHMSA regulations cover the distribution segment, as well as natural gas transmission pipelines, both of which are unregulated by the NSPS.

The Panel recommends that EPA continue consulting PHMSA to ensure that there are no overlapping or contradictory requirements on these sources.

8.4 Regulatory Flexibility Alternatives

The Panel has reviewed the information provided by EPA to the SERs and the SERs' oral and written comments from the pre-panel outreach and panel outreach. In response to this consultation, the Panel identifies the following significant alternatives for consideration by the Administrator of EPA which accomplish the stated objectives of the Clean Air Act and which minimize any significant economic impact of the proposed rule on small entities.

8.4.1 Rule Scope

SERs stated that NSPS OOOOa has unintentionally been applied to conventional and vertical wells that engage in hydraulic fracturing. SERs contend that these wells have a very different profile from unconventional and horizontal wells in terms of footprint, water usage, chemical usage, equipment used, and flowback period. SERs recommend that EPA explicitly exempt conventional and vertical wells from the proposal. EPA maintains that the original intend of the NSPS was to regulate hydraulicly fractured wells, in both conventional and unconventional reservoirs[4], and both vertical and horizontal wells.[5]

NSPS OOOOa defines hydraulic fracturing as "the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions." The NSPS does not offer numeric thresholds that define "pressurized fluids", "tight formations" or "high rate, extended flowback". When developing the original NSPS OOOO, EPA's analysis assumed hydraulic

[4] EPA-HQ-OAR-2010-0505-0445, p.4-2 and EPA-HQ-OAR-2010-0505-4546, p. 30.
[5] EPA-HQ-OAR-2010-0505-4546, p. 61.

fracturing is performed in tight sand, shale, and coalbed methane formations to have an in situ permeability (flow rate capability) to gas of less than 0.1 millidarcy.[6] EPA also assumed the flowback lasted between 3 and 10 days for the average gas well[7], and 3 days for the average oil well.[8] However, in response to a public comment on the 2015 NSPS OOOOa proposal claiming the definition of hydraulic fracturing was too broad, EPA clarified it intended to "include operations that would increase the flow of hydrocarbons to the wellhead".[9] Similarly, in response to a public comment seeking an exemption for wells that have a flowback period of less than 24 hours, EPA acknowledged that there is a range of flowback periods, finding that the requested exemption was not warranted.[10]

The Panel recommends that EPA solicit comment on appropriate definitions for 'tight formation' and 'high rate, extended flowback' to clarify the proposal's applicability.

Advocacy notes that the EPA's intent at the time of NSPS OOOO and NSPS OOOOa is not clearly stated to include conventional and unconventional reservoirs, particularly since the definition of "hydraulic fracturing" explicitly includes reference to the geologic features themselves, i.e. "tight formations," and to the operational activities that are absent in conventional reservoirs, "high rate, extended flowback." This aligns with EPA's decision in the NSPS OOOO RIA to only analyze hydraulic fracturing in such "tight formations." Nor is EPA's response to a comment about "operations that would increase the flow of hydrocarbons to the wellhead" [11] a clearly stated intent to cover geologic features other than those explicitly described in the proposed definition. Advocacy therefore recommends that EPA propose definitions with numerical standards that give meaning to the entire regulatory definition of "hydraulic fracturing," based on the SERs' characterization of the distinction between geological formations and operational characteristics likely to be the source of significant methane emissions.

8.4.2 Fugitive Emissions Requirements

8.4.2.1 Monitoring Frequency

For NSPS OOOOa, EPA is evaluating revisions to resolve discrepancies between the 2020 Technical Rule and the 2016 NSPS OOOOa, unchanged by the 2020 Policy Rule. This includes aligning VOC and methane monitoring frequencies. SERs recommend EPA adopt the VOC monitoring and associated reporting and recordkeeping provisions from the 2020 Technical Rule and apply those to methane. Advocacy recommends that EPA propose aligning the monitoring

[6] EPA-HQ-OAR-2010-0505-0445, p.4-2.
[7] EPA-HQ-OAR-2010-0505-0445, p.4-1.
[8] EPA-HQ-OAR-2010-0505-5021, p.20.
[9] EPA-HQ-OAR-2010-0505-7632, p.3-113.
[10] EPA-HQ-OAR-2010-0505-7632, p.3-64.
[11] EPA-HQ-OAR-2010-0505-7632, p.3-113.

frequency in NSPS OOOOa with the revised provisions for VOCs in the 2020 Technical Rule. EPA recommends that it reanalyze the best system of emission reduction for both pollutants, acknowledging that what was found to not be cost-effective for VOC in the 2020 Technical Rule may change when accounting for emission reductions of both VOC and methane.

8.4.2.2 Low Production Well Sites

SERs provided a number of recommendations for low production well sites, ranging from completely exempting these well sites, requiring a maximum of annual monitoring, or providing an offramp as wells reach low production status. SERs contended that low production well sites have little to no emissions, and EPA should delay proposing requirements until results of a DOE study on emissions from these sites is available. SERs recommended that EPA focus its proposed requirements on 'super emitters' or 'fat-tail' emissions. SERs also recommended that EPA revise its definition of low production well sites to align with the IRS definition of a stripper well property.

The Panel recommends EPA propose fugitive emission requirements that target sources with large emissions or super emitters. EPA and Advocacy recommend that such a proposal impose fewer requirements on sources that are less likely to emit methane and/or have demonstrated a history of insignificant emissions. Advocacy and EPA recommend that, if EPA proposes annual screening requirements, these requirements contain clear thresholds for follow-up monitoring, including a de minimis level that warrants no further action. Advocacy further recommends that EPA solicit comment on regulatory alternatives to minimize the number of well sites subject to monitoring, particularly at well sites that emit insignificant amounts of methane. EPA recommends that it solicit comment on regulatory alternatives that prioritize monitoring on well sites that emit significant amounts of methane.

The Panel further recommends that EPA solicit comment on regulatory alternatives for low production well sites. EPA and Advocacy note that such a solicitation should include a range of options, including exempting these sites and providing an offramp for well sites that later become low production well sites, such as EPA has proposed in the past. The Panel recommends that EPA solicit comment on the factors that could make certain well sites less likely to emit methane, including geologic features, equipment onsite, production levels, and any other factors that could establish the basis for an exemption or off-ramp. The Panel further recommends that EPA solicit comment for additional data, such as the DOE study, that assess the emissions from low production well sites and subsequently use this data to evaluate how monitoring requirements can be tailored to address sources mostly likely to be the sources of largest emissions and, if warranted, subcategorize sources unlikely to emit significant amounts of methane.

Regarding the definition of low production well site, the EPA contends that aligning its NSPS definition with the IRS definition is inappropriate. The IRS averages production over a calendar year of production, while the EPA averages production over the first 30 days of production after drilling or hydraulic fracturing. In the case where low production well sites have different requirements from other well sites, the affected facility would need to determine which set of requirements to follow, and waiting for a full year of production data would be infeasible. Advocacy recommends that the EPA solicit comment on the use of the IRS definition of low production well sites following the initial production period.

8.4.2.3 Exemptions

In addition, SERs supported maintaining the NSPS OOOOa wellhead only exemption from fugitive emissions requirement, and include this same exemption in the NSPS OOOOb proposal. This provision in NSPS OOOOa excludes from fugitive emissions monitoring a well site that is or later becomes a wellhead only well site, which the 2020 Technical Rule defines as "a well site that contains one or more wellheads and no major production and processing equipment." EPA and Advocacy agree that EPA should maintain the wellhead only exemption from fugitive emissions requirements in NSPS OOOOa and propose a similar provision in the proposal for NSPS OOOOb.

8.4.2.4 Monitoring Technology

SERs recommended that EPA allow audio, visual, and olfactory (AVO) and soap bubble tests as an option for finding fugitive emissions, particularly because they are lost cost and easy to implement alternatives for detecting leaks. EPA clarified that soap bubble tests are a permissible option as part of Method 21. The Panel recommends that EPA continue to allow Method 21 as an option for fugitive emissions monitoring. The Panel recommends that EPA engage in additional outreach to small entities to ensure that there is an adequate understanding of the requirements and flexibilities that are already part of Method 21.

NSPS OOOOa allows AVO in limited and appropriate circumstances, including the inspection of cover and closed vent systems, but EPA believes AVO is inappropriate as the primary method for fugitive emissions inspections of well sites and compressor stations. EPA recommends maintaining AVO inspections in these limited circumstances in NSPS OOOOb. Advocacy recommends EPA propose allowing AVO as an alternative in limited circumstances, such as part of an off-ramp for facilities unlikely to emit more than insignificant methane or with a demonstrated history of insignificant emissions.

8.4.2.5 Alternative Technology

SERs supported the use of aerial, satellite, and other forms of monitoring for fugitive emissions requirements beyond traditional LDAR, but only as an alternative and not as an additional requirement. The Panel recommends that EPA consider the cost and scope of alternative technologies and propose alternative screening technology. EPA and Advocacy support proposing alternative screening technology as a compliance option rather than an additional regulatory requirement. The Panel further recommends that EPA try to minimize significant additional reporting and recordkeeping requirements. EPA and Advocacy recommend proposing emissions thresholds for alternative screening technology that would allow small businesses to adopt any alternative compliance options without significant additional reporting or recordkeeping requirements and without needing to seek prior approval or changes to Clean Air Act permits.

8.4.3 Pneumatic Controller Requirements

SERs stated that zero emission controllers are not feasible at wells sites or other locations without reliable electricity, and installing gas-fired compressors to provide sufficient air for instrument air systems may defeat the purpose by ultimately increasing emissions, and the installation of electric service would be extremely expensive.

EPA and Advocacy recommend that the EPA only propose zero emission controllers at sites with reliable and consistent onsite power available and clearly state that the intent is not require the installation of electric services for this purpose.

8.4.4 Liquids Unloading Requirements

Some SERs questioned whether EPA could regulate liquids unloading because best practices are very 'site-specific.' To the extent that EPA includes liquid unloading requirements in the proposed NSPS OOOOb, SERs recommended that the EPA limit the requirements to best management practices. SERs stated that liquids unloading can take many forms, from simply blowing a gas well down to a tank bailing an open hole to swabbing a cased hole to various types of artificial lift. A SER identified a source for an industry best practices to which EPA should align its requirements.

Advocacy recommends that EPA not propose liquids unloading requirements. Advocacy is concerned that a best management practice written into a regulation, particularly one that is very 'site-specific,' will not provide small entities clear instructions and lead to confusion and significant risk of unwarranted enforcement actions. In addition, Advocacy is concerned that EPA did not present the Panel or SERs more specific information about the need to regulate liquids unloading or likely costs. Should EPA propose liquids unloading requirements, Advocacy recommends that EPA only propose best management practices during liquids unloading operations that align with industry best practices and give operators clear discretion to manage on-site operations to minimize venting and ensure operational safety. Further, Advocacy recommends that the proposal explicitly recognize the wide range of legitimate and allowable practices during liquids unloading that may result in some emissions. Advocacy recommends

EPA require only limited recordkeeping associated with any liquids unloading operation and not require any reporting.

EPA recommends that the NSPS OOOOb proposal include a robust set of best management practices during liquids unloading operations to minimize venting. The industry best practices provided by a SER allow exemptions for multiple types of liquids unloading operations, including swabbing and the use of plunger lifts, and suggest only monitoring the manual unloading process and closing wellhead vents to the atmosphere as soon as practicable. EPA believes that the industry best practices are not sufficient to minimize venting from liquids unloading operations, and in particular, the number of exemptions would allow a significant portion of this emissions source to go unregulated.

The Panel recommends that EPA solicit comments on exemptions for operations that may be unlikely to result in emissions, such as wellheads that are not operating under positive pressure.

8.4.5 Storage Vessels

SERs discussed concerns with the current regulatory approach towards storage vessels. First, SERs recommended establishing a regulatory off-ramp based on interconnected tanks that are operated as a single unit but currently regulated as multiple sources. EPA and Advocacy recommend that EPA propose that NSPS OOOOb applies to tank batteries rather than single storage vessels. EPA and Advocacy agree that EPA propose an off-ramp for tank batteries with emissions that later fall below a certain threshold of VOC and methane emissions.

Second, SERs raised concerns that situations exist where propane or other fossil fuel must be used to maintain continuous pilot lights for flares that serve as control devices on storage tanks that do not produce enough emissions. The Panel agrees that this issue deserves greater study, including whether the GHG benefits of these control devices are negated by the need to burn additional fossil fuels and whether additional factors exist that may cause variability in emissions from storage tanks or could be used to more narrowly target these requirements to limit the unnecessary operation of flares. The Panel recommends that EPA request comment on this issue.

One SER identified a conflict with a lease requirement for BLM leases in Michigan require operators to open the tank hatches daily to check oil levels, for the purposes of royalty calculation and loss prevention. This requirement however negates the emissions benefit of any emissions limitation. Advocacy recommends EPA request more information about this situation from BLM, including consultations with BLM. If this requirement exists in Federal, State or tribal leases, then EPA should propose an exemption for affected storage tanks. EPA consulted with BLM on this issue and found that BLM requires tank gauging monthly and this does not require opening the thief hatch. The Panel recommends that EPA continue to consult with BLM on its oil and gas regulations to ensure the regulations are harmonized, good government practice, and that owners and operators have clarity on compliance requirements if they are subject to both BLM and EPA regulations.

8.4.6 Compressors

A SER expressed opposition to changing rod packing requirements from a fixed timeline to a performance standard based on flow measurement. Advocacy notes that this consistent with small business concerns that compliance with performance standards are often more expensive because of the monitoring and recordkeeping. Small businesses frequently prefer design standards that are explicit in their requirements and do not require additional monitoring.

Advocacy recommends that, if EPA proposes a rod packing requirement based on flow measurement or other performance standard, EPA should propose an alternative compliance strategy based on time in service or hours of operation. EPA believes that the flow measurement is a straightforward and low cost compliance strategy. EPA recommends maintaining the alternative compliance strategy of routing reciprocating compressor emissions to a process.

SERs expressed opposition to EPA's suggested definition of a 'centralized production facility' a specific type of well site that operates with a larger number and size of equipment than individual well sites. One SER stated that Colorado's definition of this type of facility was inappropriate because it would inadvertently capture all well sites with a single well head and a compressor.

EPA and Advocacy agree that, if EPA proposes to regulate compressors at centralized production facilities, the definition of these facilities should clearly exclude single well head sites with small compressors.

8.4.7 Requirements for Certification by Professional Engineers

SERs addressed aspects of NSPS OOOOa that require a professional engineer (PE) certification. SERs argued that this requirement did not recognize the significant industry-specific experience available in-house at many firms and thus unnecessarily raised costs for small businesses. They recommended relaxing the requirement for to allow engineering certifications "to include those with a mathematical, geological and other related educational disciplines combined with a fixed amount of experience in the design, operations, construction and maintenance of oil and natural gas facilities." In the 2020 Technical Rule, EPA expands the NSPS OOOOa requirements to allow either a PE or an in-house engineer to complete these certifications. Advocacy and EPA recommend that EPA maintain the flexibility for in-house engineers to complete these certifications in NSPS OOOOa and include this same flexibility in NSPS OOOOb.

APPENDIX A: List of Materials EPA shared with Small Entity Representatives

Appendix A1. Materials EPA shared with potential SERs before the Pre-Panel Outreach Meeting, June 29, 2021

- Agenda for Pre-Panel Outreach Meeting, June 29, 2021
- Power Point Presentation: An Overview of the Small Business Advocacy Review Panel Process
- Power Point Presentation: Oil and Natural Gas Sector New Source Performance Standards - Small Entity Representative Pre-Panel Outreach
- Appendix - Fugitive Cost from 2020 TSD

Appendix A2. Materials EPA shared with SERs before the Panel Meeting July 29, 2021

- Agenda for Panel Outreach Meeting, July 29, 2021
- Power Point Presentation: Oil and Gas SBAR Panel Presentation
- Power Point Presentation: Oil and Gas SBAR Panel Presentation - Supplemental Materials
- Pre-Panel Comments from Potential SERs

APPENDIX B: Written Comments Submitted by Small Entity Representatives

Appendix B1. Written Comments from potential SERs following the June 29, 2021 Pre-Panel Outreach Meeting

Appendix B1 is a compilation of documents containing all written comments received from SERs following the pre-panel meeting.

- American Public Gas Association, City of Las Cruces Utilities/Gas, Middle Tennessee Natural Gas Utility District, Pensacola Energy, and Unitil Corporation
- CountryMark, Indiana Oil and Gas Association (INOGA), and Kentucky Oil and Gas Association (KOGA)
- Cumberland Valley Resources, LLC
- Fore Energy Partners, Inc (FEPI)
- Kansas Independent Oil & Gas Association (KIOGA)
- Michigan Oil and Gas Association (MOGA)
- Pennsylvania Grade Crude Oil Coalition (PGCC) and Cameron Energy Company
- The Petroleum Alliance of Oklahoma (PAO)
- Texas Alliance of Energy Producers

Appendix B2. Written Comments from SERs following the July 29, 2021 Panel Outreach Meeting

Appendix B2 is a compilation of documents containing all written comments received from SERs following the panel meeting.

- Catalyst Energy, Inc
- CountryMark, Indiana Oil and Gas Association (INOGA), and Kentucky Oil and Gas Association (KOGA)
- Cumberland Valley Resources, LLC
- Michigan Oil and Gas Association and Fore Energy Partners, Inc. (MOGA and FEPI)
- Pennsylvania Grade Crude Oil Coalition (PGCC) and Cameron Energy Company
- The Petroleum Alliance of Oklahoma (PAO)
- Texas Alliance of Energy Producers

- Texas Independent Producers and Royalty Owners Association (TIPRO), the Independent Petroleum Association of America (IPAA), and the Gas and Oil Association of WV, Inc (GO-WV)
- Western Energy Alliance (WEA)