Appendix B:
Written Comments Submitted by Small Entity Representatives

Small Business Advocacy Review Panel on EPA's Planned Proposed Rule

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

Nicole,

Below are my comments and concerns that I have come up with regarding the latest efforts to control Methane emissions. I appreciate you passing them along to whomever might be willing to read them.

Rudy Vogt
Cumberland Valley Resources, LLC

After the conference call with EPA on the 19th, I have come up with two areas that really concern me. Again, I would guess that the small volumes of gas, be it Methane, VOC's, or all natural gas, that might be vented from a KY oil well being fraced and flowed back, a pumping well (we don't have many plunger lift systems in KY because of reservoir pressures), or leaky gas gathering systems, are not typically the size sources that EPA is looking to reduce or eliminate. But once again, until we get some clarity, the small operator becomes collateral damage.

Most of the oil wells in KY that are stimulated are done so with strait fluid or fluid energized with nitrogen. Even the energized fracs would only flow back to the surface for a short time (a few days or less) before they would be put on pump (rod) and the frac fluid removed. In my mind, the real issue comes when an oil well is being cleaned up, and often for the entire life of production, the produced gas is vented. The typical east KY oil well that I am familiar with, produces less than 500 cubic feet of natural gas per Bbl of oil, and our typical vertical well produces less than 10 BOPD initially and less than 50% of the initial production after a year. Gathering and producing gas from a low pressure oil well is sensitive, because holding too much pressure on the well can be detrimental to oil production. In order to produce gas from a low pressure oil reservoir, the gas gathering system the well is to be connected to has to be at very low pressure, often below 5 psi. This is not insurmountable, and there are many oil wells in east KY that gas is gathered from, but the typical high Btu of the gas makes it un-saleable to local pipelines. Much of the gas produced from oil reservoirs has to be stripped of the majority of the heavier fractions (Propane, Butane, Pentane, & natural gasolines) before it can be sold. When LNG prices were high, this processing was feasible and even desirable, but at today's prices, it is a burden. A significant number of the oil wells that would normally be drilled could not be, if they would not have the ability to vent or flare the small amount of gas produced. In west Kentucky, there are practically no gas gathering systems to move the produced gas to. Similar to east Kentucky, the amount of gas produced per barrel of oil is small, typically less than 1 Mcf/day per Bbl, and decreases quickly with production. But without the ability to vent or flare the gas produced, oil development would come to an end. Flaring gas is another problem. Most oil wells quickly reach a point where they are not continuously pumped. When pumping is stopped, gas production declines and often quits completely. The cost to install and maintain a continuously burning pilot flame for a well that pumps for only a few hours a day would be an expensive burden on the operator.

Fugitive emissions are the other issue I see for the small operator of gas gathering systems. The typical gas gathering system in east KY has less than 50 wells connected and the gas from the wells is comingled and ends up at a compressor where the gas is compressed, dried, and delivered into a "intermediate" pipeline for sale. The whole system might be less than 10 miles, made of plastic, and is regularly patrolled for breaks or leaks, but the manpower needed to look for and fix leaks less than an 1,000 cubic feet per day is significantly higher than the manpower currently needed to look for significant leaks or breaks. Old gas gathering systems, and even some old "midstream" pipelines, may have significant leaks, some with losses of greater than 25%. The cost to the small operator to find and repair very small leaks on an old gathering system could be quite high. EPA might be willing to "grandfather" the old systems, but like with old vessels, would adding a new well to an old system make it an "effected facility" and require bringing it up to new standards? A lot of times that would not be economically feasible and would preclude any further development in the areas the old pipeline would service. This could be keep small operators dependent on the midstream pipeline, from continuing to develop their properties, effectively shutting down new drilling and gas production.

I think the biggest questions that need to be answered for the small operators in Kentucky are; 1) what volume of natural gas being vented from an individual source(well) is acceptable to EPA , 2) what volume of natural gas leaking from plumbing will require attention, and will all the plumbing associated with a well be treated as one source, 3) will a gas gathering pipeline be treated a one "facility" that would have an overall percentage loss limit, or would each leak on the pipeline have to be identified and determined if it is above a threshold and needs repair, 4) are operators looking to eliminate and/or control some volume of natural gas or some defined weight of VOC's, and 5) how can you accurately determine the volume leaking at a particular point, like a pipeline coupling with a thread leak, without having to purchase expensive equipment or hire expensive consultants?

Thanks for your time.

Rudy Vogt
Cumberland Valley Resources, LLC

MIDSTREAM'S GREATEST RESOURCE

May 28, 2015

Nicole Owens
Director, Regulatory Management
Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Re: Comments on Small Business Advocacy Review Panel for the EPA rulemaking "Emissions Standards for New and Modified Sources in the Oil and Natural Gas Sector"

Dear Ms. Owens,

Thank you for the opportunity to provide additional comments on information we would like to see during the Small Business Advocacy Review Panel (SBAR) process that will assist us in providing meaningful comments on the potential impact on gas processors that are small businesses. I have consulted with GPA's small business members, including our two Small Entity Representatives (SERs), and compiled the additional comments below.

During the May panel outreach meting it became clear that EPA had read through and evaluated GPA's previously submitted comments on EPA's White Papers on potential sources of emissions in the oil and gas sector. We appreciate EPA going through and focusing on our previous submitted comments.

As we go through this process we want to reemphasize that it would be helpful to have a greater understanding of EPA's response to GPA's original comments on the EPA's White Papers in order to evaluate this potential rule on methane emissions.

During this process it would be very beneficial if EPA addresses the following issues listed below. Having more information and /or answers to the below issues would provide the foundation to properly evaluate EPA's proposal's impact on small gas processors.

Fugitive Emissions

According to the data in EPA's White Papers, gas processing accounts for less than 10% of the emissions that EPA is trying to control. Since this is such a low percentage how will EPA ensure a cost effective fugitive emissions reduction program for processing plants beyond what they are already doing. If a small business is required to purchase expensive equipment or dedicate a significant portion of time to compliance then we will need more information on how EPA will ensure that the compliance cost will not negatively impact small businesses. More specifically, what steps does EPA plan to take to ensure small businesses are not burdened with excessive compliance costs.

Pneumatic Controllers

It would be beneficial to know if EPA is proposing switching to or requiring an instrument air system to be installed. This is an extremely costly option and would be cost prohibitive for small gas processing operations.

Pneumatic Pumps

Gas processing plants have a very small number of pneumatic pumps. It appears that there is little benefit trying to control pneumatic pump emissions from gas processing plants. It would be beneficial to know if EPA still plans on focusing on pneumatic pumps.

Compressor Seals

Capture options for small facilities include installation of vapor recovery systems. This option can be costly and problematic for small entities. Anytime you have an ultra-low pressure system capable of capturing vapors from packing vents, you also have the problem of pulling air/oxygen into the system. When you mix the two you can easily get explosive mixtures. Factor in that a number of these facilities are in remote locations and are only used if they are absolutely necessary. It would be helpful to know if EPA is still considering vapor recovery systems as an option.

Compliance Issues for Small Businesses

An LDAR program for a small plant can run anywhere from $15,000 to $30,000 per year. This is a significant cost for small businesses. The paperwork involved with monitoring the LDAR can be quite burdensome. It is important that any paperwork requirements required by EPA are minimal and simple. Small companies do not have the extra staff to monitor complicated regulatory systems nor the budget to purchase such systems. Most, if not all, small businesses track all record keeping and compliance documents in excel spreadsheets. It would help our evaluation of the impacts to small businesses to know what steps EPA is considering to lessen the potential burdens (time, labor, costs). Small businesses are very sensitive to overhead costs. Therefore, many times employees are cross trained or perform a variety of tasks. Adding additional compliance requirements would result in either an increase in headcount or an increase in cost to outsource the duty.

EPA should not charge excessive fines and should provide a way to resolve compliance issue for small business in non-punitive/financial way. It would be helpful to know if EPA is considering this.

GPA hopes that EPA will be able to address the above listed issues. If you have questions, please contact me at (918) 493-3872 or by email at mhite@gpaglobal.org.

Sincerely,

Matthew Hite
Vice President Government Affairs
Gas Processors Association

Nicole,

Jonah Energy LLC would like to provide the following general questions and comments for consideration by COB May 28, 2015, to allow us to provide more detailed comments further along in the process.

1. Is EPA's focus in upcoming proposed rulemaking to tighten standards on emission source categories that are already somehow regulated, or is EPA's focus more on rulemaking for emission source categories that aren't currently covered by existing regulation?
2. Are emission source categories that are not covered by the 5 white papers also being considered?
3. Has EPA considered lengthening the current rulemaking schedule? As a small business, we need ample time to budget for potential regulatory impact and the current schedule identifies less than 1 year from a proposed rule to final rule.
4. Would EPA consider off-ramp provisions in proposed rulemaking for various emission source categories, to allow for less regulatory burden as well production declines?

Thank you,

Chuck Cornell
Sr. Regulatory Lead
Jonah Energy LLC

Ms. Owens,

Included here are my questions in preparation for the Panel meeting tentatively scheduled for next month. As discussed, these questions are the information I am requesting in order to understand the impact of the rule to small operators like PDC. I have prepared questions based on an understanding that the sources covered in the five EPA White Papers are the ones being considered for this rule. If you have any questions or would like to discuss any of these further, please do not hesitate to let me know.

General: These questions are geared to help the group tailor comments and review to better assist the goals of the panel.

1. It was mentioned on the May 19 conference call that this panel was not convened prior to the August 23, 2011 proposal of NSPS OOOO but is necessary for this revision. Can you please elaborate on what changed between that version and this one?
2. Can you share a cost impact analysis or regulatory impact analysis that we can comment on from the small business perspective (such as how assumptions might differ for small businesses)?

Compressors:

1. Is the intent of this amendment to bring the compressor requirements discussed in the white papers to small compressors at well sites?
2. If so, are there any differences between current requirements and requirements for these small, remote compressors?

LDAR: There are a lot of different variables that can go into an LDAR program, all of which can impact the cost of the program. Any further understanding of the scope of the LDAR requirements to the upstream oil and gas sector will be essential to providing valuable feedback; specific questions are listed below.

1. What is the scope of facilities these requirements will apply to? Does it include CBM?
2. What are the thresholds for applicability? What will be used to determine the threshold (throughput, equipment, other)?
3. What is the frequency of inspections?
4. What are the monitoring methods?
5. What is the implementation timeline? Will there be a phase in?
6. What is the expectations for repair (first attempt, final repair, etc.)?
7. Are you considering exemptions for streams based on content (low VOC content, produced water, glycol, etc.)?
8. What recordkeeping and reporting elements will be included?

Oil well completions:

1. What are the differences between the existing gas well completion requirements and the new oil well completion requirements?

Pneumatics:

1. What are the changes to the existing pneumatic requirements?

Well Liquid Unloading

1. The White Papers and many comments on the white papers discuss the complexity of well liquid unloading and that evaluation must often be done on a case-by-case, well-by-well basis. Can you provide generally what requirements you are considering for well liquids unloading for a federal regulations?
2. Are you considering liquids unloading for gas wells, oil wells, or both?
3. What recordkeeping and reporting elements will be included?

PennEnergy Resources, LLC

May 27, 2015

RE: Pre-Panel Comments to Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector - PennEnergy Resources, LLC

Dear Ms. Owens:

I work in the natural gas industry for PennEnergy Resources, a small, private, Pennsylvania based company located in the Pittsburgh area. PennEnergy has been in business since 2011 and we are regulated under certain sections of 40 CFR 60 Subpart OOOO as well as several Pennsylvania specific permitting rules, policies, and emissions reporting requirements.

Since inception, we have grown from 2 employees to 32 employees. Our business activities also result in the indirect employment of hundreds of Pennsylvania citizens in good paying jobs at supporting industries. PennEnergy has invested over $300 million in Southwest Pennsylvania to date; with over $115 million going directly to local landowners in the form of lease bonuses. We are welcome in the communities in which we operate and have already significantly improved the existing infrastructure in many areas and will continue to do so as we develop our acreage. We drill, develop and operate unconventional natural gas wells in approximately 72,000 acres in three counties north of Pittsburgh, PA.

Our experience with Quad O is related to our "new" operations in the Appalachian Basin that we have evaluated under the rule as promulgated. The natural gas produced from our Butler County area is considered "dry". Accordingly, testing results determined a typical average of 0.026 tons per year volatile organic compounds (VOC) produced per produced water storage vessel. As such, VOC emissions from our storage vessel operations are below the regulatory definition of an "affected storage vessel facility" and are not subject to Quad O. We have no data yet from our wet gas acreage in Beaver County to assess applicability at this time as no wells are in production yet.

PennEnergy insists upon 100% compliance with all applicable rules and regulations and we have the outstanding environmental performance record to support this. We also support responsible regulations that truly protect our environment, as do most other operators in the state. My day-to-day job for PennEnergy involves the specific details of environmental compliance and reporting, with the ultimate responsibility of protecting human health and the environment. I collect and report our operational data related to solid waste, air emissions, and wastewater. However, I am a department of one and I am also responsible for company-wide health and safety issues. I wanted to share the following issues for your consideration as you contemplate further proposed rulemaking for the VOC and methane reduction to the Oil and Gas Industry.

Double Coverage / Redundant Requirements - The Pennsylvania Department of Environmental Protection's (PADEP) Bureau of Air Quality already regulates unconventional natural gas producers. All well pad operations must either obtain an individual air emissions permit (i.e., Plan Approval) or be able to regularly demonstrate that well pad and related equipment emissions are below permitting thresholds under Pennsylvania's *Exemption 38*[1]. I submitted several documents to the U.S. EPA (by email to Ms. Nicole Owens on May 19) showing the details and complexities of the PA Exemption 38 program. The Exemption 38 requirements include regular leak detection and repair, compliance demonstrations, "Quad O" type reporting for flowback and flaring, and a demonstration of pad-wide compliance with a maximum of 2.7 tons per year of VOC emissions along with a demonstration of compliance with other pollutant limitations. We are required to calculate and submit emissions data on our Pad wide operations (we have multiple wells per pad) as part of a required Compliance Demonstration Report to be submitted within 180 days of start-up.

As a very small company and one with only one regulatory professional (me), I am concerned that any new requirements related to an expansion of Quad O regulations or alternatively, the development and implementation of Control Technique Guidelines (CTG) for operations currently unaffected by Quad O will be redundant with those already required here in PA (e.g., Exemption No. 38, DEP Oil and Gas Reporting- Electronic (OGRE) emissions reporting, etc.). PennEnergy and many other small operators have experienced this first hand with the required Quad O Daily Flowback Logs (Well Development Daily Logs) and compliance demonstration for the Tank VOC limits of 6.0 tons per year. I believe that recent PA air emissions data (2014 data submitted March 1, 2015) from the industry will show that the state requirements have been successful in reducing methane and VOC emissions on a per well basis. Additionally, I need to hire consultants and professional engineers to assist with understanding and complying with these very complex air regulations (state and Federal).

Unintended Consequences – Due to technical issues, almost all O&G operators flare during flowback of O&G wells prior to turning wells into the production line. We are in the business of producing natural gas for sale as a safe, plentiful, and clean fuel and are mildly insulted when chastised about flaring (i.e., burning product). Even with an available gathering system near the wellhead, it is rarely feasible to be able to go directly from the separator to the production line without some flaring until the gas is relatively water free. Daily Flowback logs submitted to the state and U.S.EPA already demonstrate the time and duration of the flaring and flowback (see section below). As noted in the White Papers on Flowback Flare units, most have unknown flare efficiencies. Although increasing flare efficiencies of the flare stack during this short-term activity (hours to days) would indeed decrease methane emissions, there can also be unintended consequences. There are some flare stacks that are available at increased cost but also are very loud and would likely trigger local nuisance noise issues. Available noise suppression systems can also be problematic. The tried and true means to achieve high efficiency combustion (U.S. EPA tested to 99%+) and to limit noise is to use a ground level enclosed combustor. However, such flaring units are generally rated much lower than the required heat loading rate (in MMBTU/Hr) which would be required to flare gas efficiently in some of our operating area. Such units are also not readily available.

High Tech Leak Detection Equipment – In our experience with Quad O implementation and PA Exemption 38 here in Pennsylvania has been that vendors tried to "sell" FLIR remote sensing

[1] Pennsylvania Department of Environmental Protection Document No. 275-2101-002 "Air Quality Permit Exemptions" http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-96215/275-2101-003.pdf

equipment as a "required" technology under Exemption No. 38. We had (and still have) new vendors/contractors who have purchased the ~$100,000 FLIR camera, specifically referenced in Exemption No. 38, to "survey" our well pad emissions at a cost of ~$4,500 (minimum weekly charge). Unfortunately, they (the vendors) usually have little or no experience in operating these expensive camera systems. We chose to not use these systems and have elected instead use PADEP approved Method 21 (an alternative method under Exemption No. 38) testing equipment that can actually identify and quantify the emissions associated with leaking components. Any "enhanced" leak detection requirements for either VOCs or methane should build in flexibility in terms of providing multiply ways to demonstrate compliance. And a critical consideration has to be the cost of those compliance options to the small entities. "One-size fits all" often disproportionately affects the small entities.

Estimating and Reporting Emissions – Comprehensive emissions from well pad operations are already required to be submitted annually to the PADEP through the OGRE system. Emissions required to be reported include engines used during drilling and completions, flowback and flaring, production sources, and fugitive emissions. Pennsylvania's required operations and emissions reporting by operators and producers are comprehensive and complete. Additional/parallel operations and emissions reporting to U.S. EPA as required under various programs (e.g., 40 CFR Part 98 Subpart W, Subpart OOOO, etc.) is redundant, time and resource consuming, and with no apparent value for protection of the environment.

Minimum Emissions Applicability Threshold – Please consider a minimum trigger for a proposed reporting threshold (Quad O or new requirements)… such as the 25,000 metric ton threshold for Greenhouse Gas (GHG) reporting or another such lower threshold. CTGs for VOC, if and when developed and implemented, should also take magnitude of operations into account and include an overall VOC emission applicability threshold, excluding small producers from applicability if emissions are less than the threshold. Although we have several large volume gas wells, we remain a small producer and have not yet triggered the GHG reporting threshold in our three years of operation (that will likely change in 2016). This aggregate of all our CO2e equivalent emissions across all of our areas of operation and includes all produced geologic formations (Utica, Marcellus and Upper Devonian).

The PADEP estimates that there are over 100,000 legacy oil (and gas) wells in the Commonwealth and I am not sure how these would "fit" into the proposed regulatory structure or even be subject to regulation. If such wells will be regulated, please consider a de minimis oil well definition to cover such legacy wells.

Specific Details – The details matter! Our experience from trying to guess what the U.S. EPA needed for Quad O Daily Flowback Logs (Well Development Daily Logs) was extremely painful. Figure out ahead of time exactly what you want for a functioning report (and why) and clearly define how such information is to be provided. We created our own set of flowback activities based on **actual activities** that are typically performed for a flowback operation (see below). The U.S.EPA now has a year worth of these logs… so what? It doesn't inform the reviewer about the emissions, only the flowback operations!

PennEnergy Resources, LLC

PennEnergy Resources Well Development Daily Log

Well Name:	W75 - 1H				
Well Coordinates:	40.708469 / -79.815428				
Pad Address:	237 Westminster Road Clinton Township, PA				
Well API #:	37-019-22106-00				
DATE	5/20/2014	5/21/2014	5/22/2014	5/23/2014	5/24/2014
Duration of Recovery to Flow (Sales) Line in Hours	0.00	10.00	24.00	24.00	10.00
Duration of Flow to Combustion Device (Flare) in Hours	0.00	5.00	0.00	0.00	0.00
Duration of Venting in Hours (should be zero, if not explain below)	0.00	0.00	0.00	0.00	0.00
Duration with Fluids Flow Back Only in Hours	15.00	9.00	0.00	0.00	0.00
Duration with No Flow Back in Hours	9.00	0.00	0.00	0.00	14.00
Total Daily Hours	24	24	24	24	24

Collaboration is Important - In addition to your hired contractors, please include the overall industry and specifically small operators in your draft rulemaking process (i.e., beyond the current small business process) in a truly collaborative manner (i.e., beyond the public comment period) and you will get a much better and clearer outcome. While we acknowledge and appreciate the small business process, we still do not know what the U.S. EPA has in mind beyond the general information included in the various White Papers and would welcome the opportunity to work with U.S. EPA on the draft rulemaking package. We understand that there is resistance to release draft language, but to the extent you can share concepts that EPA might be leaning toward and ask for feedback on "this option" versus "that option," that would still improve the process. We appreciate that at this stage in the process we are supposed to be informing you if we have enough information on the proposal. In many ways we are left to "crystal ball" what the rule will look like so the more you can share, the more substantive our feedback will be.

I appreciate the opportunity to participate in this process and welcome any comments or questions.

Sincerely,
PennEnergy Resources, LLC

Doug Mehan
Director Health, Environmental & Safety

PIOGA®
Pennsylvania Independent Oil & Gas Association

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May 28, 2015

Nicole Owens
Director, Regulatory Management
USEPA Headquarters
William Jefferson Clinton Building
1200 Pennsylvania Avenue, N. W.
Washington, DC 20460

Dear Ms. Owens:

Introduction

The Pennsylvania Independent Oil & Gas Association's (PIOGA) roots go back to 1918 when the Pennsylvania Oil, Gas and Minerals Association (POGAM) was created to represent conventional oil and natural gas interests. In 1978 a group of independent Pennsylvania conventional natural gas producers left POGAM to form the Pennsylvania Natural Gas Associates (PNGA) and in 1981 that organization's name changed to the Independent Oil and Gas Association of Pennsylvania (IOGA of PA). After this split POGAM generally represented conventional oil production in northwest PA and IOGA of PA represented natural gas developers in southwestern PA. Over the years IOGA of PA's membership expanded to include Pennsylvania conventional oil producers as well as other service companies and individuals interested in the development of oil and natural gas resources in Pennsylvania. On April 1, 2010, IOGA of PA reunited with POGAM and the name of our reconstituted organization changed to the Pennsylvania Independent Oil & Gas Association.

While we do not solicit or maintain information on the size of our member companies, we are a member-driven organization and work closely with our members through established committees and so we know how large, or more precisely for this matter, how small they are. The vast majority of our members, particularly those that would be subject to or affected by the rule requirements have fewer than 500 employees and so qualify as small businesses. Indeed, many of our conventional producer members are "mom and pop" 3rd and 4th generation companies and even our largest conventional producers have much fewer than 500 employees. Accordingly, in this matter we are able to represent the unique interests of our small entity members that would be subject to or affected by the rule requirements.

PIOGA appreciates the opportunity to serve as a small entity representative (SER) to the Small Business Advocacy Review Panel (SBARP) upon its formal creation. Various members of PIOGA participated on the Pre-Panel Outreach Meeting with Potential SERs on May 19, 2015. The meeting was productive and educational. We understand that to make the actual Panel Outreach Meeting, tentatively scheduled for mid-June 2015, as productive as possible, potential SERs must provide feedback to you by close of business on May 28, 2015. We further understand that the feedback should focus on whether we, as SERs, have enough information to be able to determine whether these potential regulatory actions – 1) further control VOCs though revisions to 40 C.F.R. Part 60, Subpart OOOO, and 2) an entirely new set of New Source Performance Standards (NSPS) focused on methane emissions – may adversely affect small businesses. Sufficient information to make this determination is essential to our role as SER, which we understand is to provide advice and recommendations to the SBARP concerning options the EPA may consider that minimize impacts on small businesses while still meeting statutory obligations under the Clean Air Act.

While it is helpful to know the suite of potential mitigation options are limited to those listed in the Methane White Papers issued by EPA in April 2014, we are still left to our imaginations as to what those regulations will look like and, accordingly, whether they may adversely affect small entities. One fact is certain – creating an entirely new set of methane NSPS for the exploration and production segment of the industry is unnecessary and will disproportionally affect small entities. Keeping the next set of regulations limited to additional VOC regulations through revision to Subpart OOOO would most likely be the single best measure to limit the differential adverse impact of new regulations on small entities. By the very nature of the size of these companies, there is often, at best, one person tasked with understanding the environmental regulations (that same person is probably also tasked with safety and health compliance as well). The learning curve for Subpart OOOO was steep enough. EPA should not burden these entities with yet another set of regulations requiring additional reporting and monitoring requirements for a different pollutant when the supplemental environmental benefits are neither shown nor apparent.

Lessons Learned (Hopefully) from Subpart OOOO

For many small entities, Subpart OOOO represented their first significant exposure to the Clean Air Act and generally it was not positive. The outcry for regulation for the "oil and natural gas industry" was a reaction to the evolution of high volume hydraulically fractured (or "stimulated") and horizontally drilled shale plays. From a small entity perspective there was a rush to judgment as to what was cost-effective and a "one-size fits all" approach. Perhaps the classic example of this was the reduced emission completion requirement that calculated cost-effectiveness assuming an average flowback period of 7 days. The regulations completely ignored an entire class of wells, those traditionally known as "low pressure wells" with flowback periods measured in hours or two - three days. The economics underlying the reduced emission completion requirement simply don't work for those wells. Similarly, the technical/scientific complications associated with separation from energized wells was ignored. These are the types of issues that EPA must evaluate going forward. Some useful and informative conversations on oil well completions have been had, but it is unreasonable to expect small entities to provide information on controls they have not seen.

Another major issue was the time frames for compliance. Even though EPA tried to accommodate those concerns with phased in control requirement for storage vessels, it was still difficult for small entities to comply or even to determine if they were in compliance. There was both a shortage of consultants and equipment to come into compliance in a timely manner. The larger players could easily tie up the limited supply of consultants and, to the extent a consultant was available, the services came at premium cost. Some entities were left to "roll the dice" and guess whether the regulations applied. They should not have been put in that position then, and should not be now with respect to either of these regulatory actions. At the Pre- SBARP meeting, potential SERs were asked to provide specific examples. We will try to provide specifics, but the short time frame has precluded us for providing that information at this time. To a certain extent the small entities may not have the time or resources to conduct such an evaluation no matter how much time is allowed. Again, we will endeavor to provide such information but, respectfully, it is the job of the EPA to ensure – in the first instance – that its regulations take into consideration the cost to all affected facilities, especially small entities.

Finally, with regard to lessons learned from Subpart OOOO, the leak detection and repair (LDAR) requirements in the original proposal were extremely onerous. To EPA's credit some of those requirements were changed and gave operators options to demonstrate compliance. With the White Papers focusing on LDAR, PIOGA members are concerned that the new requirements will take away that flexibility and will require regulated companies to obtain extremely expensive monitoring equipment or to hire yet another set of consultants to do the testing. PIOGA incorporates in their entirety the comments of another potential SER, Sarah Bartlett, and call attention particularly to her comments on LDAR . The variables listed by Ms. Bartlett have tremendous impact on costs. The problems for small entities are exacerbated because, as stated above, there is often only one person responsible for compliance and the wells/sources can be spread out over a significant geographic area. PIOGA also requests that EPA survey existing state requirements for LDAR, minimize duplication of reporting/monitoring requirements, and allow consistency between the state and federal requirements where possible.

Size is important – any new regulatory burdens must be crafted to ensure that small entity operators are not disproportionally impacted

As a small entity our position is that there needs to be a clear distinction between large gas and oil producers compared to small gas and oil producers, taking into consideration both the type of well (i.e., high yield commercial shale wells vs. stripper wells) and the annual volume of natural gas produced. It appears in the "White Papers" that the bulk of the data developed and relied upon by EPA was based on modern unconventional shale plays, such as the Bakken and the Eagle Ford. It is unclear if the information includes representative data collected in the Appalachian basin from both historic stripper well fields, as well as the modern shale plays. The unconventional shale plays almost universally produce larger quantities of oil and gas from different geological formations and exhibit vastly different hydrocarbon profiles. As a result, the resulting "emission standards" are not appropriate for conventional operations; thereby forcing smaller conventional producers to comply with overly stringent requirements that are not cost-effective. It would be helpful if the Panel could provide data demonstrating that it has accurate, relevant data on conventional operations in the Appalachian Basin. If that information has not been gathered, PIOGA suggests that the applicability of additional regulations under Subpart OOOO or new NSPS for methane be delayed until the impact of those regulations can be evaluated and EPA can demonstrate that those regulations are cost effective for the small entities. It appears that the benchmark well type and associated production facilities predominantly reflect large scale wells that are typical of modern unconventional shale plays. The "White Papers" do not address stripper wells and their associated completion practices and production equipment. EPA must examine this subset of wells common in the Appalachian basin and determine if emissions reductions can be achieved in a cost effective manner. One size fits all regulations that affect the range of practices in the oil and natural gas production industry are unfair, impractical, and unnecessary

We suggest that EPA consider establishing a threshold, production, emissions, revenue or other standard that clearly delineates a "white line" for regulatory applicability. For example, if a business does not emit sufficient GHG (or produce a certain MMcf of gas or Bbl of oil) to be required to report under 40 CFR Part 98, then that entity should be exempt from any additional requirements of 40 CFR Part 60 Subpart OOOO or new methane regulations. If EPA has reviewed or explored such standards, that information would be extremely helpful (indeed, is required) in determining the potential impact of future regulations on small entities.

Stripper Wells should be categorically exempt from the proposed regulations

Stripper wells are defined by the average daily production from the well. The Internal Revenue Service (IRS) does not address the individual well, but instead defines stripper well property as a property where the average daily production of domestic crude oil and domestic natural gas produced from the wells on the property during a calendar year divided by the number of such wells is 15 barrels (barrel equivalents) or less. These are combined definitions from Internal Revenue Code (IRC) 613A(c)(6)(E) and IRS Manual 4.41.1.9 Oil and Gas Handbook; Definition of Terms Pertaining to the Oil and Gas Industry.

The IRS uses barrels or barrel equivalents in order to have a universal stripper definition for oil, gas and combined oil/gas production. When stripper well gas is produced, one must know the conversion of MCFs to BBLs. The IRS states in 613A(c)(8)(D)(iv) "each 6,000 cubic feet of domestic natural gas shall be treated as 1 barrel of domestic crude oil." In addition, almost all sources outside of the IRS state that 6 MCF is "roughly", "approximately", or "about" 1 BOE (Barrel Oil Equivalent). (A webpage for Total, the French energy company, called Oil Industry Conversions gave the conversion factor as follows: "1 barrel of oil equivalent = 5,487 cubic feet of gas. Natural gas is converted to barrels of oil equivalent using a ratio of 5,487 cubic feet of natural gas per one barrel of crude oil. This ratio is based on the actual average equivalent energy content of TOTAL's natural gas reserves." This was the only MCF to BOE conversion found that varied (only slightly) from the IRS version.) This is a case where the approximate value is reasonable.

So with the necessary values known, one can now do the math.

15 BOED = Stripper Well (Oil, Gas & Combined)
6 MCFD = 1 BOED; or 6 MCFD per 1 BOED; or 6 MCFD/1 BOED
15 BOED x 6 MCFD/1 BOED = 90 MCFD = Stripper Gas Well

Oil wells that produce less than or equal to 15 BOED or gas wells that produce less than or equal to 90 MCFD should not be subject to additional regulation.

Additional Concerns and Comments:

1. The proposed additional emission standards are a concern to small entities as they pertain to compressors, liquids unloading, and fugitive emissions. As an example, some small entity natural gas and oil producers utilize small reciprocating compressors at their wells. These compressors are typically driven by 18 or 20 bhp engines, moving small amounts of natural gas. The compressor standards discussed in the "White Papers" are concerning, because they imply that the proposed standards will be derived from larger compressors (such as a stage 3 compressor) moving significantly larger quantities of gas, compressing into significantly higher line pressures (500 to 1,000 psig). Information on the size of compressors and/or any potential exemptions below a certain bhp would be helpful in evaluating the potential impact of the regulations.

2. The industry is in a down-turn. Small entity operators, particularly ones that own, operate, and maintain shallow conventional wells in the Marcellus region have taken the hardest hit during this downturn. While NYMEX might indicate a natural gas price of $3 per MMBtu (or Therm), due to the glut of gas in the region the actual local prices for natural gas might be as low as 50% or less of the NYMEX price. We suggest that the cost/benefit analysis of any proposed new regulations take the actual local prices of natural gas into account in the analyses when determining the economic impact of such rules on small entity

operators. If EPA has accounted for such regional/local price difference in the cost effectiveness analysis, that information would help us evaluate the potential impact of the regulations.

3. Due to costs associated with increased regulation, PIOGA conventional operators have not engaged in any new well development in several years. For example, one PIOGA member paid a consultant over $35,000 to simply determine compliance with new state and federal air regulations and compliance reporting preparation/submittal. Again – this did not include the cost of coming into compliance or the ongoing reporting and monitoring costs. On the small margins that certain small entities operate, that can be the difference between drilling and not drilling. Additional regulations will only exacerbate this problem. Small entity operators simply cannot absorb these additional economic burdens, especially during this regional business downturn. Additionally, the environmental benefit of additional regulations on small entity operators is unlikely to outweigh the economic impact on their operations. We suggest that the cost/benefit analysis of any proposed new regulations consider the actual local prices of natural gas into account in the analyses when determining the environmental benefit of such rules on the environment when imposed on small entity operators.

4. It is very burdensome (or even impossible) for small operators to determine what it is the EPA is requiring/proposing when it comes to emissions due to the cut-off requirements not corresponding to traditional industry language that is easy to interpret. We suggest that any new regulations that will impact small entity operators be written in a clear manner, without ambiguity, that is easily understood and interpreted by the entire oil and gas industry. We also suggest that this be accomplished by EPA working with small entity operators in a collaborative manner to obtain meaningful input and ensure that any new regulatory proposals do not cause disproportionate regulatory, financial, or compliance impact.

5. The State of Pennsylvania has an Air Quality Program in place. "Exemption 38a." states that a conventional well (stripper well – low pressure and volume) and its associated equipment is exempt from more rigorous air quality permitting requirements in accordance with the State Implementation Plan (SIP). To avoid overlap and ambiguity, the EPA needs to review and consider the requirements of each SIP to determine if additional and redundant air quality regulations at the federal level are truly required for small business operators.

Sincerely,

Kevin J Moody

General Counsel
PIOGA

cc: Lou D'Amico
Shane Kriebel
David Ochs
Roy Rakiewicz
Matt Kellogg
James Elliott

WESTERN ENERGY ALLIANCE

May 27, 2015

Nicole Owens
Director, Regulatory Management
U.S. Environmental Protection Agency
1200 Pennsylvania Ave. NW
Washington, DC 20460

Dear Ms. Owens:

Western Energy Alliance, in its role as a Small Entity Representative (SER), respectfully submits the following comments to the Small Business Advocacy Review (SBAR) Panel for EPA rulemaking Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector. The EPA is soliciting SER input for its SBAR Panel to offer the perspective of small entities that will be required to comply with EPA's forthcoming rulemaking.

Western Energy Alliance represents over 450 companies engaged in all aspects of environmentally responsible exploration and production of oil and natural gas in the West. The Alliance represents independents, the majority of which are small businesses with an average of fifteen employees.

We do not believe that EPA has not provided adequate information at this time to provide input on the cost to small entitites of the forthcoming rulemaking, which limits the scope and specificity of the input we are able to provide at this time. EPA has not provided SERs with critical information like the scope of affected facilities, the implementation timeline, recordkeeping requirements or a regulatory impact analysis, all of which shape our understanding of EPA's proposed action.

We are also concerned about the timing of this comment process. Based on documentation provided by EPA's Office of Policy, the timeline proposed indicates that the SBAR Panel process will conclude this summer and that the draft rule will also be issued later this summer. This timeline appears overly aggressive and we question whether it will provide EPA adequate time to review SBAR input and incorporate meaningful changes into the draft rulemaking. We urge EPA to pursue a timetable that provides for a thorough review of the comments provided by the SERs, which are taking significant time away from their small businesses to provide thoughtful input on this process.

Although EPA has not provided specific information on the upcoming rule, we anticipate the inclusion of Leak Detection and Repair (LDAR) requirements and we have significant concerns on this topic. We urge EPA to avoid the Colorado Regulation 7 LDAR program as a national model, as it would be extremely burdensome for small operators without offering significant environmental benefit. The frequency of inspections and reporting requirements are costly, especially for operators with remote operations that require extensive travel time.

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The Colorado LDAR program is not a suitable national model, and suffers from a lack of air quality modeling to quantify expected emission reductions. Without modeling, the claimed program benefits are inaccurate. The Colorado rules render many marginally economic wells uneconomic, which is especially burdensome to small entities. In the current price environment, losing these marginal wells would risk putting many small operators out of business.

A methane control strategy for upstream oil and natural gas operations threatens to skew the economic hardship towards small upstream operators without offering cost-effective reductions. Instead, a control strategy aimed at achieving the greatest emission reductions at the lowest incremental cost must focus on the natural gas processing, transmission and storage sectors. EPA's own series of white papers on emission sources notes that upstream methane emissions from compressors are 86,000 MT at gas production sites versus 1,985,000 MT from gas processing, transmission and storage sites. These downstream operations emit at 23 times the rate of upstream sites and clearly present the opportunity to achieve greater emission reductions. Upstream compressor controls would be extremely burdensome for many small operators given the significant capital expense associated with compressors and would clearly miss the bulk of emission reduction opportunities, which are found downstream.

According to a study by the University of Texas, Austin, methane emitted from all upstream source categories at natural gas production sites represents just 0.42% of gross natural gas production volumes.[i] Chasing a small source of emissions is not cost-effective, and will be particularly burdensome on small producers. In addition, it is counterproductive to the President's overall climate change goals, as greater use of natural gas, particularly for electricity generation, is one of the main reasons for decreases in overall U.S. greenhouse gas emissions. Putting in place expensive requirements to capture a small source of emissions at the upstream sector will result in less natural gas production, higher prices for consumers, and hence, less climate change benefit.

Thank you for considering these comments and recommendations. We appreciate the opportunity to participate in the process. However, to provide meaninful input, it is necessary to have more information about EPA's intentions with the rulemaking and actual details so that we and other SERs can provide detailed information on the economic impact to small businesses. We look forward to additional details so that we can help EPA understand the full cost implications.

Sincerely,

Kathleen M. Sgamma
Vice President of Government & Public Affairs

[i] Measurements of methane emissions at natural gas production sites in the United States, http://www.pnas.org/content/110/44/17768

DEPARTMENT OF ENVIRONMENTAL PROTECTION
Air Quality

DOCUMENT NUMBER:	275-2101-003
TITLE:	Air Quality Permit Exemptions
EFFECTIVE DATES:	July 26, 2003, August 10, 2013 for Category No. 33 and Category No. 38 Exemptions
AUTHORITY:	Act of January 8, 1960, P.L. (1959) 2119, No 787, as amended, known as The Air Pollution Control Act, (35 P.S. § 4001 et seq.)
POLICY:	Plan Approval and Operating Permit Exemptions
PURPOSE:	The document provides criteria for sources and physical changes to sources determined to be eligible for permitting exemptions as sources of minor significance.
APPLICABILITY:	Staff/Regulated Public
DISCLAIMER:	The policies and procedures outlined in this guidance document are intended to supplement existing requirements. Nothing in the policies or procedures shall affect applicable statutory or regulatory requirements. The policies and procedures herein are not an adjudication or a regulation. There is no intent on the part of the Department to give these rules that weight or deference. This document establishes the framework for the exercise of DEP's administration discretion in the future. DEP reserves the discretion to deviate from this policy statement if circumstances warrant.
PAGE LENGTH:	21 pages

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DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR QUALITY

NOTICE
Plan Approval and Operating Permit Exemptions

Consistent with the applicable provisions of the Pennsylvania Air Pollution Control Act (APCA), 35 P.S. §4001 *et seq.* and 25 *Pa. Code* § 127.14 (relating to exemptions), the Department of Environmental Protection (Department) may determine sources or classes of sources to be exempt from the plan approval and permitting requirements of 25 *Pa. Code* Chapter 127 (relating to construction, modification, reactivation and operation of sources). This guidance document identifies the following: exemptions under Section 127.14(a); exemptions under Section 127.14(a)(8) that do not require submission of a Request for Determination (RFD) form; exemption criteria that the Department may use when an owner or operator of a source or a facility is seeking an exemption from plan approval; further qualifications regarding plan approval exempted sources; exemptions under Section 127.14(a)(9) related to physical changes; and exemption criteria for operating permits. This amended guidance document is applicable to sources that will be constructed as new or modified sources after the effective date of this document. It does not apply to sources that were constructed or modified prior to the effective date of this guidance document and operating lawfully without a permit. Sources exempted from plan approvals are not automatically exempted from operating permit requirements.

Words and terms that are not defined in this document have the meaning set forth in 25 *Pa. Code* §121.1 (relating to definitions) or the APCA (35 P.S. § 4003), 25 *Pa. Code*, Chapters 121 - 145 and applicable definitions codified in the Code of Federal Regulations including 40 CFR Parts 60 and 63.

Listing of Plan Approval Exemptions

Section 127.14(a) Exemptions

In accordance with § 127.14(a), approval is not required for the construction, modification, reactivation or installation of the following:

1. Air conditioning or ventilation systems not designed to remove pollutants generated by or released from other sources.

2. Combustion units rated at 2.5 million or less Btus per hour of heat input.

3. Combustion units with a rated capacity of less than 10 million Btus per hour of heat input fueled by natural gas supplied by a public utility or by commercial fuel oils which are No. 2 or lighter-viscosity less than or equal to 5.82 C St--and which meet the sulfur content requirements of § 123.22 (relating to combustion units). Combustion units converting to fuel oils which are No. 3 or heavier-viscosity greater than 5.82 C St or contain sulfur in excess of the requirements of § 123.22 require approval. For the purpose of this section, commercial fuel oil shall be virgin oil which contains no reprocessed, recycled, or waste material added.

4. Sources used in residential premises designed to house four or less families.

5. Space heaters which heat by direct heat transfer.

6. Mobile sources.

7. Laboratory equipment used exclusively for chemical or physical analyses.

8. Other sources and classes of sources determined to be of minor significance by the Department.

Section 127.14(a)(8) Exemptions

The following is a list of those sources and classes of sources determined, in accordance with § 127.14(a)(8), to be exempt from the Plan Approval requirements of §§ 127.11 and 127.12. The commencement of construction of sources is exempted from the plan approval requirements provided the exemption criteria are met. Unless labeled otherwise, emission rates are to be considered actual tons per year (tpy). Note that certain exceptions and qualifications regarding this list are contained in the discussion that follows the list.

1. Incinerators with rated capacities less than 75 lb per hour burning a municipal or residual waste as defined by the Bureau of Land Recycling and Waste Management.

2. Shot blast and sandblasting units with appropriately designed fabric collectors, cartridge collectors or scrubbers manufactured as an integral part of the design and which have exhaust volumes equal to or smaller than 5,000 scfm.

3. Combustion turbines rated at less than 1,000 horsepower or 10.7 gigajoules per hour.

4. Internal combustion engines rated at less than 100 brake horsepower. Note Category 38 addresses oil and gas facilities.

5. Portable, temporary internal combustion engines used for 14 days or less at special events (such as county fairs, circuses and concerts).

6. Internal combustion engines regardless of size, with combined NOx emissions less than 100 lbs/hr, 1000 lbs/day, 2.75 tons per ozone season and 6.6 tons per year on a 12-month rolling basis for all exempt engines at the site.

7. Natural gas-fired heat-treating furnaces with less than 10 million Btus per hour heat input (fuel burning emissions only).

8. Steam aspirated vacuum degassing of molten steel.

9. Coal handling facilities processing less than 200 tons per day. (Thermal coal dryers and pneumatic coal cleaners remain subject to the requirements of § 127.11). This exemption includes internal combustion engines meeting the criteria for plan approval exemption described in category 6 above.

10. Wet sand and gravel operations (screening only) and dry sand and gravel operations (including crushers) processing unconsolidated materials with a rated capacity of less than 150 tons per hour.

11. Coal and non-metallic mineral handling activities directly associated with either deep or surface mines that consist only of conveyors and non-vibratory screens (aka. grizzlies). This exemption includes internal combustion engines meeting the criteria for plan approval exemption described in category 6 above.

12. Portable crushers that are controlled with properly located water sprays or with fabric filters, have a rated capacity less than 150 tons per hour, operated during daylight, and located on a site for less than 60 days; provided, however, that the crushers do not process materials containing asbestos. This exemption includes; associated screens and drop points; tub grinders used to mulch grubbing waste; and, internal combustion engines meeting the criteria for plan approval exemption described in category 6 above.

13. Concrete batch plants and associated storage vessels that are equipped with appropriately designed fabric collectors.

14. Bulk material storage bins, except those associated with a production facility with total actual facility particulate emissions greater than 10 tpy.

15. Storage vessels for volatile organic compounds [which do not contain hazardous air pollutants (HAPs)] which have capacities less than 40 m^3 (10,000 gallons) based on vessel dimensions, unless subject to § 129.59 (bulk gasoline terminals) or § 129.60(b) and (c) (bulk gasoline plants).

16. Storage vessels containing non-VOC, non-malodorous, or nonhazardous air pollutant materials.

17. Diesel fuel, Nos. 2, 4 and 6 fuel oils, or kerosene and jet fuel storage and dispensing facilities as long as the stored or dispensed product has a vapor pressure less than 1.5 psia.

18. Covered wastewater transfer systems such as covered junction boxes, sumps, and tanks at industrial sites.

19. Plastic bead or pellet milling, screening, and storage operations (does not include handling and storage of resin powders).

20. Plastic parts casting ovens and injection molding processes.

21. Tire buffing.

22. Paper trimmers/binders.

23. Vocational education shops. Chemistry laboratories at schools and colleges.

24. Bench-scale laboratory equipment used for kinetic studies, mass/energy transport studies, chemical synthesis and physical or chemical analysis.

25. Research and development activities with annual emission rates:

i. less than or equal to 20 tpy of CO;

ii. less than or equal to 0.12 tpy of lead;

iii. less than or equal to 3 tpy of PM_{10};

iv. less than or equal to 8 tpy of SO_2 or VOC;

v. less than or equal to 10 tpy of NO_x;

vi. less than or equal to one tpy of a single HAP or 2.5 tpy of a combination of HAPs.

26. Woodworking facilities including sawmills and pallet mills which process green wood; or, small woodworking facilities processing kiln-dried wood or wood products (flakeboard, particleboard, etc.) associated with pattern shops, retail lumber yards, shipping and packing departments, etc. This category also includes woodworking facilities of any size processing kiln-dried wood or wood products equipped with appropriately designed fabric collectors designed to have emission rates that are less than 0.01 gr/dscf.

    This exemption does not apply to woodworking facilities processing wood that has been treated with a wood preservative of any kind. The term "woodworking facilities" refers only to operations in which wood or a wood product is sawed, sanded, planed, or similarly shaped or reshaped. The term does not include such activities as painting, finishing, hardboard manufacturing, plywood manufacturing, and the like.

27. Smokehouses.

28. Slaughterhouses (rendering cookers remain subject to the requirements of § 127.11).

29. Restaurant operations.

30. Degreasing operations using solvents containing no more than 5% VOC by weight, except those emitting more than 2.7 tons of VOCs or those subject to the Federal NESHAP for halogenated solvent cleaners under 40 CFR Part 63.

31. Sources of uncontrolled VOC emissions not addressed elsewhere in this exemption listing modified or newly added, such that emission increases are less than 2.7 tpy. Facilities' claiming this exemption must provide a 15-day prior written notification to the Department and limit VOC emission increases to less that 2.7 tpy.

32. Dry-cleaning facilities that are not subject to § 129.70, NSPS, MACT (area MACT sources are currently deferred from plan approval and operating permit requirements), PSD or NSR requirements.

33. a. Retail gasoline dispensing facilities and similar vehicle-fueling operations at industrial facilities.

    b. Compressed natural gas dispensing facilities meeting the following requirements:

i. Combined NO_X emissions from the stationary internal combustion engines at a facility less than 100 lbs/hr, 1000 lbs/day, 2.75 tons per ozone season (the period beginning May 1 of each year and ending on September 30 of the same year) and 6.6 tons per year on a 12-month rolling basis. The emissions criteria do not include emissions from sources which are approved by the Department in plan approvals, general plan approval/general operating permits or emissions from sources at the facility approved under Category No. 33(a).

ii. Combined VOC emissions from all the sources at the facility less than 2.7 tons on a 12-month rolling basis. If the VOCs include HAPs, the HAP exemption criteria in this paragraph must be met. Compliance with this criterion will be determined using any generally accepted model or calculation methodology. Combined HAP emissions [not including Polychlorinated Biphenyls (PCBs), Chromium (Cr), Mercury (Hg), Lead (Pb), Polycyclic Organic Matter (POM), Dioxins and Furans] at the facility less than 1000 lbs. of a single HAP or one ton of a combination of HAPs in any consecutive 12-month period. The emissions criteria do not include emissions from sources which are approved by the Department in plan approvals, general plan approval/general operating permits, or emissions from sources approved under Category No. 33(a) at the facility.

iii. The owner or operator of the compressed natural gas fueling station will annually perform a leak detection and repair (LDAR) program that includes either the use of an optical gas imaging camera such as a FLIR camera or a gas leak detector capable of reading methane concentrations in air of 0% to 5% with an accuracy of +/- 0.2% or other leak detection monitoring devices approved by the Department. The LDAR program will be conducted on valves, flanges, connectors, storage vessels/storage tanks, and compressor seals in natural gas or hydrocarbon liquids service. Leaks are to be repaired no later than 15 days after leak detections unless facility shutdowns or ordering of replacement parts are necessary for repair of the leaks. For the storage vessel, any leak detection and repair are to be performed in accordance with 40 CFR Part 60, Subpart OOOO.

   A. A leak is considered repaired if one of the following can be demonstrated:

      1. No detectable emissions consistent with Method 21 specified in 40 CFR Part 60, Appendix A;

2. A concentration of 2.5% methane or less using a gas leak detector;

3. No visible leak image when using an optical gas imaging camera;

4. No bubbling at leak interface using a soap solution bubble test specified in Method 21. A procedure based on the formation of bubbles in a soap solution that is sprayed on a potential leak source may be used for those sources that do not have continuously moving parts and that do not have a surface temperature greater than the boiling point or less than the freezing point of the soap solution; or

5. Any other method approved by the Department.

B. Leaks, repair methods and repair delays are to be recorded and maintained for five years. If a gas leak detector is used, a leak is to be detected by placing the probe inlet at the surface of a component. The Department may grant an extension for leak detection deadlines or repairs upon written request from the owner or operator of the facility documenting the justification for the requested extension.

34. Sources of particulate matter (not subject to NESHAPs, NSPS, PSD, or major source requirements) that are controlled by a baghouse, have an emission rate which meets the limits of Chapter 123, and are exhausted indoors and cannot be bypassed to exhaust to the outdoor atmosphere. These sources should not emit more than 0.12 tpy of lead, one tpy of a single HAP or 2.5 tpy of a combination of HAPs. Multiple sources within this category may be exempt from plan approval requirements.

35. Sources emitting inert gases only, such as argon, helium, krypton, neon, and xenon; pure constituents of air such as nitrogen, oxygen, or carbon dioxide; or, methane or ethane.

36. Source(s) qualifying under § 127.449 as de minimis emission increases.

37. Sources that exhaust to a filter/baghouse and have particulate loading (before control) below limits specified in Chapter 123.

38. Oil and gas exploration, development, and production facilities and associated equipment and operations meeting the following provisions:

a. Conventional wells, wellheads and all other associated equipment. A conventional well is any well that does not meet the definition of unconventional gas well in 58 PA.C.S § 3203.

b. Well drilling, completion and work-over activities.

c. Non-road engines as defined in 40 CFR § 89.2.

d. Unconventional wells, wellheads, and associated equipment, provided the applicable exemption criteria specified in subparagraphs i, ii, iii, iv and v are met.

i. Within 60 days after the well is put into production, and annually thereafter, the owner/operator will perform a leak detection and repair (LDAR) program that includes either the use of an optical gas imaging camera such as a FLIR camera or a gas leak detector capable of reading methane concentrations in air of 0% to 5% with an accuracy of +/- 0.2% or other leak detection monitoring devices approved by the Department. LDAR is to be conducted on valves, flanges, connectors, storage vessels/storage tanks, and compressor seals in natural gas or hydrocarbon liquids service. Leaks are to be repaired no later than 15 days after leak detections unless facility shutdowns or ordering of replacement parts are necessary for repair of the leaks. The optical gas imaging camera or other Department-approved gas leak detection equipment are to be operated in accordance with manufacturer-recommended procedures. For the storage vessel, any leak detection and repair will be performed in accordance with 40 CFR Part 60, Subpart OOOO.

A. A leak is considered repaired if one of the following can be demonstrated:

1. No detectable emissions consistent with Method 21 specified in 40 CFR Part 60, Appendix A;

2. A concentration of 2.5% methane or less using a gas leak detector and a VOC concentration of 500 ppm or less;

3. No visible leak image when using an optical gas imaging camera;

4. No bubbling at leak interface using a soap solution bubble test specified in Method 21; or a procedure based on the formation of bubbles in a soap solution that is sprayed on a potential leak source may be used for those sources that do not have continuously moving parts and that do not have a surface temperature greater than the boiling point or less than the freezing point of the soap solution; or

5. Any other method approved by the Department.

B. Leaks, repair methods and repair delays will be recorded and maintained for five years. If a gas leak detector is used, a leak is to be detected by placing the probe inlet at the surface of a component. The Department may grant an extension for leak detection deadlines or repairs upon the receipt of a written request from the owner or operator of the facility documenting the justification for the requested extension.

ii. Storage vessels/storage tanks or other equipment equipped with VOC emission controls achieving emissions reduction of 95% or greater. Compliance will be demonstrated consistent with 40 CFR Part 60, Subpart OOOO or an alternative test method approved by the Department.

iii. Combined VOC emissions from all the sources at the facility less than 2.7 tons on a 12-month rolling basis. If the VOCs include HAPs, the HAP exemption criteria in this paragraph will be met. Compliance with this criterion is to be determined using any generally accepted model or calculation methodology. Combined HAP emissions [not including Polychlorinated Biphenyls (PCBs), Chromium (Cr), Mercury (Hg), Lead (Pb), Polycyclic Organic Matter (POM), Dioxins and Furans] at the facility less than 1000 lbs of a single HAP or one ton of a combination of HAPs in any consecutive 12-month period. The emission criteria do not include emissions from sources which are approved by the Department in plan approvals, or the general plan approvals/general operating permits at the facility and the emissions from sources meeting the exemption criteria in subparagraphs i, ii, and iv.

iv. Flaring activities as outlined below:

A. Flaring used at exploration wells to determine whether oil and/or gas exists in geological formations or to appraise the physical extent, reserves and likely production rate of an oil or gas field.

B. Flaring used for repair, maintenance, emergency or safety purposes.

C. Flaring used for other operations at a wellhead or facility to comply with 40 CFR Part 60, Subpart OOOO requirements.

D. Enclosed combustion device including enclosed flare will be used for all permanent flaring operations at a wellhead or facility. These flaring operations will be designed and operated in accordance with the requirements of 40 CFR § 60.18.

v. Combined NO_X emissions from the stationary internal combustion engines at wells, and wellheads less than 100 lbs./hr., 1000 lbs./day, 2.75 tons per ozone season (the period beginning May 1 of each year and ending on September 30 the same year), and 6.6 tons per year on a 12-month rolling basis. The emission criteria do not include emissions from sources which are approved by plan approvals or the general plan approvals/general operating permits at the facility.

The owner or operator will comply with all applicable state and federal requirements including notification, record keeping, and reporting requirements as specified in 40 CFR Part 60 Subpart OOOO. The owner or operator will also demonstrate compliance with the exemption criteria using any generally accepted model or calculation methodology within 180 days after the well completion or installation of a source. The owners and operators of sources not meeting the provisions of subsections a-d of this category may submit an RFD form to the Department. If the RFD is not approved by the Department, an application for authorization to use a general permit or a plan approval application is to be submitted to the Department, as appropriate.

39. Combustion units with a rated capacity of less than 10 million Btus per hour of heat input fueled by natural gas supplied by an independent gas producer. Sources firing natural gas supplied by an independent producer shall be given the same consideration given sources that fire natural gas provided by a public utility.

40. Any source qualifying for exemption based on criteria contained in a general permit developed in accordance with the procedures described in §§ 127.601 through 127.642.

41. Powdered metal sintering furnaces using only organic lubricants equal to or less than 0.75% organic lubricant by weight. The furnace atmosphere must contain hydrogen (H_2) at 3% or greater. The furnace must also maintain an operating flame curtain between the part entry and pre-heat zone. In the absence of an operating flame curtain, the furnace must operate an afterburner.

A sintering furnace using only metal containing lubricants may be exempted if the furnace emits particulate matter not exceeding 0.15 lb./hr. (determined by mass balance or stack tests). Note, for mass balance purposes, the following conversion factors are to be used:

Zinc Stearate to Zinc Oxide particulate matter = 0.129,

Lithium Stearate to Lithium Carbonate particulate matter = 0.15.

The Department may approve alternate conversion factors provided a satisfactory written justification is submitted to the Department.

A sintering furnace using organic lubricants and operating outside the limitations specified above, may be exempted under a case-by-case determination through the execution of a Request for Determination of Requirement for Plan Approval Application form. The owner/operator of a sintering furnace exempt from permitting requirements must notify the Department within 30 days of the furnace installation. For sintering furnaces using metal containing lubricants, records must be maintained to demonstrate compliance with the particulate matter emission limit of 0.15 lb/hour for each product.

Facilities that use both organic and metal-containing lubricants are exempted if the lubricants are less than 0.75% organic lubricant by weight; and, the furnace is designed and operated as described in the preceding paragraph and emits particulate matter at rates less than 0.15 lb./hr (determined by mass balance or stack tests).

The previous exemption does not apply to sintering furnaces used to sinter parts that are treated with oil.

42. Facilities engaged primarily in collision repair and refinishing of automobiles and light duty trucks.

43. Remediation of gasoline or fuel oil contaminated soil, groundwater or surface water by equipment installed, maintained and operated as provided herein. All air exhaust points are controlled by dual, activated carbon beds operating in series or a thermal/catalytic oxidizer. For activated carbon beds, monitoring (e.g. intrinsically safe ionization detector) at an appropriate frequency (e.g., one-fourth the predicted time to breakthrough of the first bed) must be performed at the inlet, between the first and second beds and after the second bed. If breakthrough of the first bed is detected, the first bed is removed, the second bed is shifted to the first position and the new bed is placed in the second position. Monitoring, operating, and maintenance records are maintained and available to the Department upon request. Equipment installed and operated as described above must be designed to achieve a minimum VOC control efficiency of 90%. As long as actual annual emissions after control are less than one TPY VOC or HAPs, the remediation project is determined to be of minor significance in accordance with 127.14 (8), no Air Quality Plan Approval is required and no Request for a Determination (RFD) needs to be filed. Other remediation projects may be considered for exemption via a Request For Determination and may be required to obtain Plan Approval at the discretion of the Department on a case-by-case basis.

44. Any source granted an exemption by the Department through the execution of a Request for Determination of Requirement for Plan Approval/Operating Permit (RFD) form.

Further Qualifications Regarding Plan Approval Exempted Sources:

1. This notice shall not be construed to exempt facilities that include multiple sources of air contaminants, unless specifically stated in the source category.

2. The addition of any source that would subject the facility to major source New Source Review or Prevention of Significant Deterioration, Title V or Reasonably Available Control Technology (RACT) requirements shall comply with plan approval requirements, even if such sources are within a category in the above list.

3. Sources exempt from plan approval may be required to be included in the operating permit if the source is not included in the trivial activity listing.

4. Sources located in Allegheny and Philadelphia Counties may be subject to different permitting requirements. Please contact the Allegheny County Air Quality Program at 412-567-8115 or the Philadelphia Air Management Services at 215-823-7580 for information applicable to sources located in those counties.

5. Any sources claiming an exemption based on emission thresholds must keep adequate records to clearly demonstrate to the Department that the applicable thresholds are not exceeded.

These determinations do not exempt the above-listed sources from compliance with the emission limitations, work practice, and other applicable requirements contained in Chapters 121, 122, 123, 124, 127, 129, and 135. Although a source may be exempt from the plan approval and operating permit requirements of Chapter 127, the source is subject to all other applicable air quality regulations. For example, combustion units exempt from the requirements of Chapter 127 are not exempt from the opacity limitations of § 123.41 or the emission limitations of § 123.22. Storage vessels for organic compounds with capacities between 2,000 gallons to 40,000 gallons, not subject to the requirements of Chapter 127, must install pressure relief valves in accordance with the requirements of § 129.57. (Note: Storage vessels in this size range would also not be subject to the requirements of §§ 129.59 and 129.60.)

If the Department determines that any exempted source is causing air pollution in violation of Section 8 of the Air Pollution Control Act, 35 P. S. § 4008, or 25 Pa. Code 121.7, the Department may order the installation of additional air cleaning devices. In those cases, plan approvals and operating permits may be required.

Requests for exemptions from the plan approval requirements of Chapter 127 for multiple source facilities must be considered on a case-by-case basis.

As noted in Category 44 of the list, additional exemptions, when appropriate, may be obtained through the submission of a completed Request for Determination of Requirement for Plan Approval Application form. These forms are available from any of the Department's Air Quality offices and on the DEP website www. dep.state.pa.us under the Air Quality page.

Physical Changes Qualifying for Exemption Under Section 127.14(a)(9)

In accordance with § 127.14(a)(9), the Department has determined that the following physical changes qualify for plan approval exemption if the change: a) would not violate the terms of an operating permit, the Air Pollution Control Act, the Clean Air Act or the regulations adopted under the acts; b) would not result in emission increases above the allowable in the operating permit; and, c) would not result in an increased ambient air quality impact for an air contaminant. These changes may be made without notification to the Department.

Caution: Do not make determinations regarding the following list without consideration of the preceding criteria.

1. Changes in the supplier or formulation of similar raw materials, fuels, paints and other coatings which do not affect emissions and which meet all applicable standards and limitations.

2. Changes in product formulations that do not affect air emissions.

3. Changes that result in different speciation of pollutants but fall within permit limitations.

4. Changes in the method of raw material addition.

5. Changes in the method of product packaging.

6. Changes in temperature, pressure, or other operating parameters that do not adversely affect air cleaning device performance or air emissions.

7. Additions of or changes to sampling connections used exclusively to withdraw materials for testing and analysis including air contaminant detection and vent lines.

8. Changes to paint drying oven length designed to alter curing time, so long as capture efficiencies of control equipment are not altered.

9. Routine maintenance, inspection and cleaning of storage tanks and process vessels or the closure or dismantling of a storage tank or process.

10. Changing water sources to air cleaning devices when there is no effect on air cleaning device performance or air emissions.

11. Moving a source from one location to another at the same facility with no change in operation or controls.

12. Installation of an air-cleaning device that is not installed to comply with regulatory requirements and will not be used to generate emission reduction credits.

13. Repairing, replacing, upgrading, maintaining, or installing pollution control device instrumentation or component equipment including pumps, blowers, burners, filters, filter bags, devices for measuring pressure drop across an air cleaning device or a filter breakage detector for a baghouse, provided such changes would not violate an operating permit term or condition.

14. Installing a fume hood or vent system for industrial hygiene purposes or in a laboratory.

15. The temporary (no longer than six months) replacement of a source with a source of equal or less emission potential.

16. Repairing, replacing, upgrading, maintaining, or installing equipment and processes at oil and gas extraction and production facilities and operations. The category includes equipment or processes used either to drill or alter oil and natural gas to the point of lease custody transfer, to plug abandoned wells and restore well sites, or treat and dispose of associated wastes.

In accordance with § 127.14(c), additional physical changes may be determined to be of minor significance and not subject to plan approval requirements through the following procedure:

1. If the changes do not involve the installation of equipment, the changes may be made within 7 calendar days of the Department's receipt of a written request provided the Department does not request additional information or objects to the change within the 7-day period.

2. If the changes involve the installation of equipment, the changes may be made within 15 calendar days of the Department's receipt of a written request provided the Department does not request additional information or objects to the change within the 15-day period.

3. If the change would violate the terms of an operating permit the plan approval exemption may be processed contemporaneously with the minor operating permit modification under the procedures described in § 127.462.

Exemption Criteria for Operating Permits

A Title V operating permit is needed by all facilities that have the potential to emit (PTE) exceeding the levels described in the definition of "Title V facility." A state-only operating permit is needed for facilities that do not have a PTE which exceeds the Title V facility thresholds, but which has actual emissions equal to or exceeding the facility levels summarized below. An existing facility which does not have a PTE exceeding the Title V facility thresholds and which does not have actual emissions exceeding the levels shown below is exempt from the requirement to obtain an operating permit.

State-Only Operating Permit Facility Exemptions*

Pollutant	**PTE<**	**Actual Emission Rate<**
CO	100 TPY	20 TPY
NO_x	100 TPY**	10 TPY
SO_x	100 TPY	8 TPY
PM_{10}	100 TPY	3 TPY
VOCs	50 TPY**	8 TPY
Single HAP	10 TPY	1 TPY
Multiple HAPs	25 TPY	2.5 TPY

* Sources located in Allegheny and Philadelphia Counties may be subject to different permitting requirements. Please contact the Allegheny County Air Quality Program at 412-567-8115 or the Philadelphia Air Management Services at 215-823-7580 for information applicable to sources located in those counties.

* 25 TPY for Severe Ozone NA areas including Bucks, Chester, Delaware, and Montgomery counties.

Sources listed in the plan approval exemption list should be included in an operating permit application unless it is also included in the listing of trivial activities. When a RFD is issued for a source not included on the list of trivial activities the source need not be brought onto the operating permit until the renewal of the operating permit. So long as all applicable requirements are met there is no need to revise an operating permit to include a source installed under an RFD or the de minimis provisions of an operating permit. Only in the case where a physical change of minor significance would violate the terms of an operating permit should a plan approval exemption and a minor permit modification under § 127.462 be processed contemporaneously. A facility that currently has or should have a plan approval or an operating permit is not exempted from the operating permit requirements. However, if the facility would now be eligible for exemption, the owner/operator may submit a RFD in accordance with § 127.14(c).

Exempted Facility and Source Categories for Operating Permits

Unless preclude by the Clean Air Act, or the regulations there under, the following facilities and source categories are exempted from the operating permit requirements of § 127.402.

1. Residential wood stoves.
2. Asbestos demolition/renovation sites.
3. Facilities engaged primarily in collision repair and refinishing of automobiles and light duty trucks.
4. Retail gasoline stations.

Deferral of Operating Permit Requirements for Area Sources

Sources subject to MACT standards are not exempted from operating permit requirements. However, the permitting of MACT area sources will be deferred at this time. Area MACT sources emit or have the PTE less than 10 tpy of any hazardous air pollutant or 25 tpy of any combination of hazardous air pollutants. These non-major sources include: perchloroethylene dry cleaning, halogenated solvent cleaning, ethylene oxide commercial sterilization and fumigation operations, hard and decorative chromium electroplating, chromium anodizing tanks and secondary lead smelters. These MACT area sources are still required to meet all applicable emission control requirements established by the respective MACT requirement. The owner or operator of a MACT area source need not submit an operating permit application until December 9, 2004.

Trivial Activities

Trivial activities are those located within a facility, which do not create air pollution in significant amounts. These insignificant activities need not be described in a Title V or state-only operating permit application. Also, these activities do not require a plan approval. Sources listed in the plan approval exemption list should be included in an operating permit application unless it is also listed in the following list. Certain of these listed activities include qualifying statements intended to exclude many similar activities.

1. Combustion emissions from propulsion of mobile air contamination sources. The term "mobile air contamination source" means an air contamination source, including, but not limited to, automobiles, trucks, tractors, buses and other motor vehicles; railroad locomotives; ships, boats and other waterborne craft. The term does not include a source mounted on a vehicle, whether the mounting is permanent or temporary, which source is not used to supply power to the vehicle. Examples might include lawn mowers, tow and lift vehicles, and the like.

2. Air-conditioning units used for human comfort that do not have applicable requirements under Title VI of the Act.

3. Ventilating units used for human comfort that do not exhaust air pollutants into the ambient air from any manufacturing, industrial or commercial process.

4. Electric space heaters. Propane and gas fired space heaters with a plant-wide capacity less than 2.5 million Btus per hour heat input and which have not been subject to RACT requirements.

5. Electrically heated furnaces, ovens and heaters, and other electrically operated equipment from which no emissions of air contaminants occur.

6. Non-commercial food preparation.

7. Use of office equipment and products, not including printers or businesses primarily involved in photographic reproduction.

8. Any equipment, machine or device from which emission of air contaminant does not occur.

9. Janitorial services and consumer use of janitorial products.

10. Internal combustion engines used for landscaping purposes.

11. Garbage compactors and waste barrels.

12. Laundry activities, except for dry-cleaning and steam boilers.

13. Bathroom/toilet vent emissions.

14. Emergency (backup) electrical generators at residential locations.

15. Tobacco smoking rooms and areas.

16. Blacksmith forges.

17. Plant maintenance and upkeep activities (such as, grounds-keeping, general repairs, cleaning, painting, welding, plumbing, re-tarring roofs, installing insulation, and paving parking lots) provided these activities are not conducted as part of a manufacturing process, are not related to the source's primary business activity, and not otherwise triggering a permit modification.[1]

18. Repair or maintenance shop activities not related to the source's primary business activity, not including emissions from surface coating or de-greasing (solvent metal cleaning) activities, and not otherwise triggering a permit modification.

19. Portable electrical generators that can be moved by hand from one location to another.[2]

20. Hand-held equipment for buffing, polishing, cutting, drilling, sawing, grinding, turning or machining wood, metal or plastic.

21. Brazing, soldering and welding equipment, and cutting torches related to maintenance and construction activities that do not result in emission of HAP metals.[3]

22. Air compressors and pneumatically operated equipment, including hand tools.

23. Batteries and battery charging stations, except at battery manufacturing plants.

24. Storage tanks, vessels, and containers holding or storing liquid substances that will not emit any VOC or HAP.

25. Propane or natural gas tanks and containers.

26. Storage tanks, reservoirs, and pumping and handling equipment of any size containing soaps, vegetable oil, grease, animal fat, and nonvolatile aqueous salt solutions, provided appropriate lids and covers are utilized.

27. Equipment used to mix and package, soaps, vegetable oil, grease, animal fat, and nonvolatile aqueous salt solutions, provided appropriate lids and covers are utilized.

28. Drop hammers or hydraulic presses for forging or metalworking.

29. Equipment used exclusively to slaughter animals, but not including other equipment at slaughterhouses, such as rendering cookers, boilers, heating plants, incinerators, and electrical power generating equipment.

30. Vents from continuous emissions monitors and other analyzers.

31. Natural gas pressure regulator vents.

32. Hand-held applicator equipment for hot melt adhesives with no VOC in the adhesive formulation.

33. Equipment used for surface coating, painting, dipping or spraying operations, except those that will emit VOC or HAP.

34. CO_2 lasers used only on metals and other materials that do not emit HAP in the process.

35. Consumer use of paper trimmers/binders.

36. Electric or steam-heated drying ovens and autoclaves, but not the emissions from the articles or substances being processed in the ovens or autoclaves or the boilers delivering the steam.

37. Salt baths using nonvolatile salts that do not result in emissions of any regulated air pollutants.

38. Laser trimmers using dust collection to prevent fugitive emissions.

39. Bench-scale laboratory equipment used for kinetic studies, mass/energy transport studies, chemical synthesis and physical or chemical analysis.

40. Sources emitting inert gases only, such as argon, helium, krypton, neon, and xenon; pure constituents of air such as nitrogen, oxygen, or carbon dioxide; or the organic aliphatic hydrocarbon gases methane and ethane.

41. Routine calibration and maintenance of laboratory equipment or other analytical instruments.

42. Equipment used for quality control/assurance or inspection purposes, including sampling equipment used to withdraw materials for analysis.

43. Hydraulic and hydrostatic testing equipment.

44. Environmental chambers not using hazardous air pollutant (HAP) gasses.

45. Shock chambers.

46. Humidity chambers.

47. Solar simulators.

48. Fugitive emissions related to movement of passenger vehicles, provided the emissions are not counted for applicability purposes and any required fugitive dust control plan or its equivalent is submitted.

49. Process water filtration systems and demineralizers, but not including air strippers.

50. Demineralized water tanks and demineralizer vents.

51. Boiler water treatment operations, not including cooling towers.

52. Oxygen scavenging (de-aeration) of water.

53. Potable water treatment systems.

54. Ozone generators.

55. Fire suppression systems and activities involved in fire protection training, first aid or emergency medical training.

56. Emergency road flares.

57. Steam vents and safety relief valves.

58. Steam leaks.

59. Steam cleaning operations.

60. Steam sterilizers.

61. Reserved.

62. Typesetting, image setting, and plate making equipment used in the preparatory phase of printing.

If an applicant conducts an activity that is believed trivial but not covered by this listing, the applicant may list the activity in an operating permit application and provide a written justification for listing the activity as trivial. If the Department accepts the applicant's justification, no further information will be required on the activity. If the Department rejects the justification, additional information must be included in an operating permit application submitted to the Department.

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[1]Cleaning and painting activities qualify if they are not subject to VOC or HAP control requirements. Asphalt batch plant owners/operators must still get a permit.

[2]"Moved by hand" means that it can be moved without the assistance of any motorized or non-motorized vehicle, conveyance, or device.

[3]Brazing, soldering and welding equipment, and cutting torches related to manufacturing and construction activities that emit HAP metals are more appropriate for treatment as insignificant activities based on size or production level thresholds. Brazing, soldering, welding and cutting torches directly related to plant maintenance and upkeep and repair or maintenance shop activities that emit HAP metals are treated as trivial and listed separately in this appendix.

AIR QUALITY PERMIT EXEMPTIONS – CATEGORY NO. 38
CURRENT INTERNAL IMPLEMENTATION INSTRUCTIONS

This document outlines implementation instructions to assist the Pennsylvania Department of Environmental Protection staff to consistently implement the provisions of Category No. 38 of the Air Quality Permit Exemption List (Document No. 275-2101-003). These instructions do not mandate specific inspections but provide instructions when inspections are conducted. Inspectors may be any DEP staff that are conducting inspections at the site and have been trained to understand the Category No. 38 instructions.

The provisions of Category No. 38 are printed in "bold" text with the explanatory instructions in regular font type.

38. Oil and gas exploration, development, and production facilities and associated equipment and operations meeting the following provisions:

a. Conventional wells, wellheads and all other associated equipment. A conventional well is any well that does not meet the definition of unconventional gas well in 58 PA.C.S § 3203.

The term "Unconventional gas well" is defined at 58 PA.C.S. § 3203 as follows:

"A bore hole drilled or being drilled for the purpose of or to be used for the production of natural gas from an unconventional formation."

The term "Unconventional formation" is defined at 58 PA.C.S. § 3203 as follows:

"A geological shale formation existing below the base of the Elk Sandstone or its geologic equivalent stratigraphic interval where natural gas generally cannot be produced at economic flow rates or in economic volumes except by vertical or horizontal well bores stimulated by hydraulic fracture treatments or by using multilateral well bores or other techniques to expose more of the formation to the well bore."

b. Well drilling, completion and work-over activities.

Well drilling and completion activities include but are not limited to horizontal or vertical drilling, well casing, well completion, lifting and well treatment, and other work-over activities.

This exemption allows the owner or operator to commence the activities related to well drilling, completion, and other activities without any permitting requirements when they comply with the permit exemption Category No. 38 criteria.

It should be noted that completion activities are subject to 40 CFR Part 60, Subpart OOOO and the owner or operator shall comply with the applicable requirements (such as Reduced Emissions Control (REC), Flare, etc.)

c. Non-road engines as defined in 40 CFR § 89.2.

(1) An internal combustion engine is a non-road engine if:

(i) It is used in or on a piece of equipment that is self-propelled or serves a dual purpose by both propelling itself and performing another function.

(ii) It is portable or transportable (i.e., designed to be or capable of being carried or moved from one location to another). Examples of transportability include, but are not limited to, wheels, skids, carrying handles, dollies, trailers, or platforms.

Some examples of non-road engines at a natural gas production facility are drilling rigs, portable generators, and hydraulic fracturing engines.

(2) An internal combustion engine is <u>not</u> a non-road engine if:

(i) It remains at a location for more than 12 consecutive months or if it remains at a location more than two years and operates more than 3 months per year. Any engine used to perform the same or similar function that replaces the engine in question has its time on site included in the consecutive time period; or

(ii) It is regulated by a Federal New Source Performance Standards promulgated under Section 111 of the Act.

Non-road engines are regulated in EPA's 40 CFR Part 89; for more details, see 40 CFR § 89.2. Part 89 includes emission standards and associated certification requirements for non-road engines.

a. Unconventional wells, wellheads, and associated equipment, provided the applicable exemption criteria specified in subparagraphs i, ii, iii, iv and v are met.

i. Within 60 days after the well is put into production, and annually thereafter, the owner/operator will perform a leak detection and repair (LDAR) program that includes either the use of an optical gas imaging camera such as a FLIR camera or a gas leak detector capable of reading methane concentrations in air of 0% to 5% with an accuracy of +/- 0.2% or other leak detection monitoring devices approved by the Department. LDAR is to be conducted on valves, flanges, connectors, storage vessels/storage tanks, and compressor seals in natural gas or hydrocarbon liquids service. Leaks are to be repaired no later than 15 days after leak detections unless facility shutdowns or ordering of replacement parts are necessary for repair of the leaks. The optical gas imaging camera or other Department-approved gas leak detection equipment must be operated in accordance with manufacturer-recommended procedures. For the storage vessel, any leak

detection and repair will be performed in accordance with 40 CFR Part 60, Subpart OOOO.

A. A leak is considered repaired if one of the following can be demonstrated:

1. **No detectable emissions consistent with Method 21 specified in 40 CFR Part 60, Appendix A;**

2. **A concentration of 2.5% methane or less using a gas leak detector and a VOC concentration of 500 ppm or less;**

3. **No visible leak image when using an optical gas imaging camera;**

4. **No bubbling at leak interface using a soap solution bubble test specified in Method 21; or a procedure based on the formation of bubbles in a soap solution that is sprayed on a potential leak source may be used for those sources that do not have continuously moving parts and that do not have a surface temperature greater than the boiling point or less than the freezing point of the soap solution; or**

5. **Any other method approved by the Department.**

B. Leaks, repair methods and repair delays will be recorded and maintained for five years. If a gas leak detector is used, a leak is to be detected by placing the probe inlet at the surface of a component. The Department may grant an extension for leak detection deadlines or repairs upon the receipt of a written request from the owner or operator of the facility documenting the justification for the requested extension.

LEAK DEFINITION

Any leaks of gaseous hydrocarbons that can be detected by an optical gas imaging camera such as a FLIR camera or any other approved gas leak detection device is considered a leak.

A release by any equipment or component designed by the manufacturer to protect the equipment, controller, or personnel or to prevent ground water contamination, gas migration, or an emergency situation is not considered a leak.

EQUIPMENT OR COMPONENTS TO BE MONITORED FOR LEAKS

The scope of coverage of the equipment or components is dependent on the equipment or components that are located at natural gas wellheads such as valves, flanges, connectors, storage vessels/storage tanks, fittings, piping, etc.

In addition to an evaluation using a FLIR camera or gas leak detector or any other approved gas leak detection device, inspectors should search for signs of leakage from all equipment and components by:

(1) Examining the owner or operator's logs for gauge readings and compare the readings against current readings and previous results for indication of system leakage;

(2) Evaluating equipment for any wear and tear;

(3) Checking for spills of any fluids;

(4) Inspecting all equipment and components for signs of corrosion or leakage; and

(5) Inspecting floating roof in storage tank(s).

OPTICAL GAS IMAGING CAMERA

The Department does not endorse a specific manufacturer or model of optical gas imaging camera for leak detection. Inspectors should note that an owner or operator may use any optical gas imaging camera such as a FLIR camera that is designed and proven by the manufacturer to acceptably detect fugitive gaseous emissions of hydrocarbons from sources at natural gas production facilities and associated equipment. In order to ensure valid readings, the optical gas imaging camera needs to be operated in accordance with manufacturer recommended operating procedures.

QUANTIFICATION OF LEAKS NOT REGULATED BY 40 CFR PART 60 SUBPART OOOO

Using EPA method 21, the emissions are measured as organic compounds. VOC concentration may be computed from the measured organic emissions and the percent VOC in the gas stream. Inspectors should determine that an owner or operator quantifies any leaks by using the following equation:

$$TOC\ concentration \times ratio\ of\ VOC\ to\ TOC\ concentration = VOC\ concentration$$

For example, a facility showing a leak of a 0.5% TOC (0.5 ft^3 TOC/100 ft^3 of sample) gas stream of which 10% of the TOC is VOC by volume (10 ft^3 VOC/100 ft^3 TOC) resulting in a VOC concentration of:

$$\frac{0.5\ ft^3\ TOC}{100\ ft^3\ of\ sample} \times \frac{10\ ft^3\ VOC}{100\ ft^3\ TOC} = \frac{5\ ft^3\ VOC}{10{,}000\ ft^3\ of\ sample}$$

$$\frac{5\ ft^3\ VOC}{10{,}000\ ft^3\ of\ sample} \times \frac{100}{100} = \frac{500\ ft^3\ VOC}{1{,}000{,}000\ ft^3\ of\ sample} = 500\ ppm\ VOC$$

REPORTING OF LEAKS IN ANNUAL EMISSIONS REPORT AS REQUIRED BY CHAPTER 135.

Inspectors should determine if an owner or operator quantifies and includes the emissions from leaks in the annual emissions inventory report which is submitted in accordance with 25 Pa. Code Chapter 135. The emissions may be determined using any generally accepted model or calculation methodology using emission factors.

REPAIR

The term "repair" means that equipment is adjusted, or otherwise altered, in order to eliminate a leak as defined in the applicable sections of the federal regulations or as defined in the exemption criteria.

For the equipment subject to exemption criteria a leak is considered repaired if one of the following can be demonstrated:

(1) There are no detectable emissions consistent with Method 21 of 40 CFR Part 60, Appendix A;

(2) There is a concentration of 2.5% methane or less using a gas leak detector and a VOC concentration of 500 ppm or less;

(3) There is no visible leak image when using an optical gas imaging camera;

(4) There is no bubbling at leak interface using a soap solution bubble test specified in Method 21 which may only be used for those sources that do not have continuously moving parts, that do not have surface temperature greater than the boiling point or less than the freezing point of the soap solution; or

(5) There are no detectable emissions by any other method approved by the Department.

Using EPA Method 21, the emissions are measured as organic compounds. VOC concentration may be computed from the measured organic emissions and the percent VOC in the organic (carbon) stream.

For closed vent systems controlling storage vessels, repair must be performed in accordance with 40 CFR Part 60, Subpart OOOO. Subpart OOOO requires closed vent systems controlling storage vessels to be operated with no detectable emissions. Such demonstrations are required to be conducted using EPA Method 21. A potential leak interface is determined to operate with no detectable organic emissions if the organic concentration value determined is less than 500 parts per million by volume.

A first attempt of repair should be made within 5 days of detection of leak. Leaks are to be repaired as soon as practicable, but not later than 15 days after detection, unless repair may require a facility or process shutdown or require new parts for repairs.

COMPLIANCE DEMONSTRATION

Inspectors should determine if an owner or operator demonstrates compliance with the Category No. 38 exemption criteria using any generally accepted model or calculation methodology within 180 days after the well completion or installation of a source. This initial compliance demonstration to the Department may be submitted through electronic or regular mail to the appropriate Regional Air Program Manager. Inspectors are reminded that owners or operators need to maintain the records of demonstration of compliance for at least 5 years and be made available upon request.

Compliance with the exemption criteria for a gas wellhead may be demonstrated with a photograph that contains the following:

(1) Date of photograph;

(2) Longitude and latitude of the well site embedded within or stored with the photograph (or separate GIS device visible in frame); and

(3) Picture of equipment for storing or re-injecting recovered liquid, equipment for routing recovered gas to gas flow line, and the completion combustion device connected to and operating at each completion operation.

Compliance with the exemption criteria for storage vessels may be demonstrated by:

(1) An initial performance test and a periodic performance test within 60 months of a previous test;

(2) Maintaining daily average control device parameters above (or below) the minimum (or maximum) level established during the performance test;

(3) Preparing a site-specific monitoring plan for a continuous monitoring system; and

(4) Conducting initial and annual inspections of covers and closed vent systems for leaks or defects.

RECORDKEEPING, NOTIFICATION AND REPORTING

Inspectors should verify that an owner or operator is in compliance with all applicable state and federal requirements including notification, recordkeeping, and reporting requirements as specified in 40 CFR 60, Subpart OOOO.

Inspectors should verify that an owner or operator performing completions after hydraulic fracturing at gas wellheads commencing after January 1, 2015, employs reduced emissions completions (REC) and routes all salable quality gas to the gas flow line as soon as practicable. Inspectors should verify that an owner or operator documents compliance with this provision through a photograph of the recovery and completion combustion equipment that contains the location of the wellhead and the date of the completion operations.

Inspectors should verify that an owner or operator notified the EPA and the Department no later than two days prior to the commencement of each well completion. The notification can be submitted in writing or via email. As provided in 40 CFR § 60.5420, the owner and operator may send a copy of the 24-hour advance notice required under Pennsylvania's Oil and Gas Law (Act 13 of 2012) for well completions to the Air Program Manager in the appropriate DEP regional office.

The well completion notification must include the following:

(1) Contact information for the owner or operator;

(2) Anticipated date of well completion;

(3) API well number;

(4) Latitude/Longitude (5 decimal places);

(5) Planned date for beginning of flowback;

(6) Type of well (Normal, Wildcat, Delineation, Low Pressure);

(7) Type of emission control used (REC, Flaring, Neither); and

(8) If emission control used is identified as "neither," reasons why.

During every day of the well completion activity, the owner/operator maintains a daily log book containing the following information for each well completion:

(1) Location;

(2) API well number;

(3) Duration of flowback (hours);

(4) Duration of venting (hours);

(5) Reasons for venting to atmosphere;

(6) Duration of recovery to the flow line (hours); and

(7) Duration of combustion (hours).

Inspectors should verify that the owner or operator submitted an annual report for affected facilities. The annual report is due 30 days from the date the compliance period ends, with subsequent annual reports due on the same date. Owners or operators may submit a combined report for all affected facilities. The annual reports, which must be certified by a responsible official, must contain identification of affected facilities, and deviations from work practice or emission/operating limits.

Information required in annual reports must contain the following:

Wellheads: Location, API well number, duration of flowback, duration of recovery to the flow line, duration of combustion, duration of venting, specific reasons for venting, documentation for exception from control/recovery, and digital photographs, if applicable.

Pneumatic controllers: Date, location, and manufacturer's specifications.

Storage vessels: Emission calculations, records of deviation, and number of consecutive days a skid mounted or mobile source mounted storage vessel is located at a site in the oil and natural gas production segment. If a vessel is removed from a site and, within 30 days, is either returned to or replaced by another vessel at the site to serve the same or similar function, then the entire period since the original vessel was first located at the site, including the days when the storage vessel was removed, will be added to the count towards the number of consecutive days.

Inspectors are reminded that an owner or operator may record and maintain the data in electronic form or written log. Electronic monitoring and storage of LDAR data provides accuracy, an effective means for QA/QC, and helps retrieve records in a timely manner for review purposes.

The log must include the following:

(1) The equipment or component, date of leak detection, detection method and measurement data or visual image;

(2) The number of repairs not completed within 15 days. A list of all equipment or components currently on the "Delay of Repair" list, the date each component was placed on the list, reasons and the scheduled dates of repairs; and

(3) The number of equipment or components that could not be repaired and reason, if applicable.

Inspectors are also reminded that an owner or operator needs to maintain the record for leaks, repair methods and repair delays for five years and make available to the Department upon request.

ii. Storage vessels/storage tanks or other equipment equipped with VOC emission controls achieving emissions reduction of 95% or greater. Compliance will be demonstrated consistent with 40 CFR Part 60, Subpart OOOO or an alternative test method approved by the Department

VOC emissions from storage vessels or storage tanks can be controlled at more than 95% by control devices such as an enclosed combustion device or vapor recovery device, along with a cover that meets requirements established in 40 CFR § 60.5395.

Inspectors should note that an owner or operator demonstrate compliance with 95% VOC reduction requirements of storage vessels in accordance with § 60.5413.

Inspectors should note that an owner or operator may demonstrate compliance with 95% VOC reduction requirements of other equipment such as tanker truck load-outs, consistent with § 60.5413 or alternate test methods as approved by the Department.

Measures to reduce tanker truck load-outs emissions include the application of vapor recovery equipment or enclosed flare. As per EPA's AP-42, Compilation of Air Pollutant Emission Factors, the collection efficiency may be assumed to be 99.2 percent for tanker trucks passing the MACT-level annual leak test (not more than 1 inch water column pressure change in 5 minutes after pressurizing to 18 inches water followed by pulling a vacuum of 6 inches water). A collection efficiency of 98.7 percent (a 1.3 percent leakage rate) may also be assumed for tanker trucks passing the NSPS-level annual test (3 inches pressure change). If Method 27 – Determination of Vapor Tightness of Gasoline Delivery Tank Using Pressure-Vacuum Test is used for annual leak testing, it will be determined as equivalent to NSPS-level annual testing, and no additional approval is required from the Department. The leak testing performed in accordance with Department Of Transportation regulations 49 CFR 180.407 - Requirements for test and inspection specifications for cargo tanks will be determined as equivalent to NSPS-level annual testing.

iii. Combined VOC emissions from all the sources at the facility less than 2.7 tons on a 12-month rolling basis. If the VOCs include HAPs, the HAP exemption criteria in this paragraph will be met. Compliance with this criterion is to be determined using any generally accepted model or calculation methodology. Combined HAP emissions [not including Polychlorinated Biphenyls (PCBs), Chromium (Cr), Mercury (Hg), Lead (Pb), Polycyclic Organic Matter (POM), Dioxins and Furans] at the facility less than 1000 lbs of a single HAP or one ton of a combination of HAPs in any consecutive 12-month period. The emission criteria do not include emissions from sources which are approved by the Department in plan approvals, or the general plan approvals/general operating permits at the facility and the emissions from sources meeting the exemption criteria in subparagraphs i, ii, and iv.

Generally accepted models or calculation methodologies for the estimation of emissions include, but are not limited to, vendors' data, source test data from identical sources or EPA emission factors. The supporting documentation must be kept for at least 5 years and be made available to the Department upon request.

iv. Flaring activities as outlined below:

A. Flaring used at exploration wells to determine whether oil and/or gas exists in geological formations or to appraise the physical extent, reserves and likely production rate of an oil or gas field.

B. Flaring used for repair, maintenance, emergency or safety purposes.

C. Flaring used for other operations at a wellhead or facility to comply with 40 CFR Part 60, Subpart OOOO requirements.

D. Enclosed combustion device including enclosed flare will be used for all permanent flaring operations at a wellhead or facility. These flaring operations will be designed and operated in accordance with the requirements of 40 CFR § 60.18.

For a flare, inspectors shall visually examine the following:

(i) That the flare is operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours using Method 22 of Appendix A of 40 CFR Part 60. Temporary flares used as a completion combustion device is not subject to Method 22 Visible emission observations.

(ii) That the flare is operated with a flame present at all times, as indicated by thermocouple or other equivalent device. Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback

(iii) That flare is operated at all time when emissions are vented to it.

For further requirements regarding heat content specifications, maximum tip velocity, flare diameter, hydrogen content, etc., refer to 40 CFR§ 60.18.

As defined in 40 CFR § 60.5430, the term "completion combustion device" means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions. Temporary flares used as completion combustion devices are not required to meet 40 CFR§ 60.18 as subpart OOOO excludes these devices from the flare requirements.

REPORTING OF EMISSIONS FROM FLARING OPERATIONS

Inspectors should determine that an owner or operator quantified and included the emissions from flaring operations in the annual emissions inventory report which is submitted in accordance with 25 Pa. Code Chapter 135. The emissions must be determined using any generally accepted model or calculation methodology using emission factors.

v. Combined NOx emissions from the stationary internal combustion engines at wells, and wellheads less than 100 lbs./hr., 1000 lbs./day, 2.75 tons per ozone season (the period beginning May 1 of each year and ending on September 30 the same year), and 6.6 tons per year on a 12-month rolling basis. The emissions criteria do not include emissions from sources which are approved by plan approvals or general permits at the facility.

The combined NOx emission thresholds are applicable only for sources located at wells and wellheads. Compliance with this criterion shall be determined using any generally accepted model or calculation methodology for the estimation of emissions, including, but not limited to, vendors' data, source test data from identical sources, or EPA emission factors. The supporting documentation must be kept for at least 5 years and be made available to the Department upon request.

ANNUAL EMISSION INVENTORY REPORTING

The annual emissions inventory report required to be submitted in accordance with 25 Pa. Code Chapter 135 must also include the emissions from sources which are exempted from permitting requirements.

AIR QUALITY PERMIT EXEMPTION CATEGORY NO. 38 COMPLIANCE DEMONSTRATION INSTRUCTIONS FOR THE OWNERS AND OPERATORS OF OIL AND GAS EXPLORATION, DEVELOPMENT, AND PRODUCTION FACILITIES AND ASSOCIATED EQUIPMENT AND OPERATIONS

The Pennsylvania Department of Environmental Protection (Department or DEP) issued amended the Category No. 38 exemption criteria on the Air Quality Permit Exempt List on August 10, 2013(Document No. 275-2101-003). The compliance demonstration criterion requires an owner or operator to demonstrate compliance with the exemption criteria using any generally accepted model or calculation methodology within 180 days after a well completion or the installation of a source.

As defined in 40 CFR Part 60, Subpart OOOO the term "well completion" means the process that allows for the flowback of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, which may vent produced hydrocarbons to the atmosphere via an open pit or tank (See 40 CFR Section § 60.5430).

The 180-day clock for the submission of the compliance demonstration is triggered when the well completion begins once flowback starts. However, if the well is shut-in and there is no flowback, the well will be considered completed and the 180-day clock will begin after the well is shut-in.

The initial compliance demonstration submitted to the DEP may be provided through electronic or regular mail to the appropriate Regional Air Program Manager. The owner or operator is required to maintain records of the demonstration of compliance for at least 5 years and it shall be made available to the Department upon request.

These compliance demonstration instructions are designed to assist the owners or operators of sources located at well pads to consistently comply with the Category No. 38 exemption criteria on the Air Quality Permit Exemption List. The following instructions describe the type of information needed to satisfactorily demonstrate compliance with each provision of the Category No. 38 exemption criteria.

The provisions of Category No. 38 are printed in "bold" text with the explanatory instructions in regular font type.

A. Exemption Category No. 38: Provisions a. and b.

- **Oil and gas exploration, development, and production facilities and associated equipment and operations meeting the following provisions:**
- **Conventional wells, wellheads and all other associated equipment. A conventional well is any well that does not meet the definition of unconventional gas well in 58 PA.C.S § 3203.**

The owner or operator of conventional wells, wellheads and all other associated equipment are not required to submit a compliance demonstration to the Department.

- **Well drilling, completion and work-over activities.**

1. HOW TO DEMONSTRATE COMPLIANCE WITH THESE PROVISIONS

The completion activities are subject to 40 CFR Part 60, Subpart OOOO and the owner or operator is required to comply with the applicable requirements.

The owner and operator must send a copy of the 24-hour advance notice to the DEP prior to the commencement of each well completion as required under Pennsylvania's Oil and Gas Law (Act 13 of 2012). This notice must be submitted in writing, via regular mail or via e-mail to the Air Program Manager in the appropriate DEP regional office. The advance notice submitted to the DEP under Act 13 also satisfies the advance notice requirements for well completion operations subject to 40 CFR § 60.5420 (a)(2).

2. DOCUMENTS REQUIRED TO BE SUBMITTED TO THE DEPARTMENT TO DEMONSTRATE COMPLIANCE FOR WELL COMPLETION NOTIFICATION REQUIREMENT:

The well completion notification must include the following:

(i) Contact information for the owner or operator;

(ii) API well number;

(iii) Latitude/Longitude coordinates for each well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983;)

(iv) Planned date of the beginning of flowback;

3. RECORDS TO BE MAINTAINED DURING EVERY DAY OF THE WELL COMPLETION ACTIVITY:

During every day of the well completion activity, the owner/operator is required to maintain a daily log book containing the following information for each well completion:

(i) Location;

(ii) API well number;

(iii) Duration of flowback (hours);

(iv) Duration of venting (hours);

(v) Reasons for venting to atmosphere;

(vi) Duration of recovery to the flow line (hours); and

(vii) Duration of combustion (hours).

4. DOCUMENTS REQUIRED TO BE SUBMITTED TO THE DEPARTMENT TO DEMONSTRATE COMPLIANCE WITH REDUCED EMISSIONS COMPLETION (REC) REQUIREMENTS

(i) Contact information for the owner or operator;

(ii) Location;

(iii) API well number;

(iv) Duration of flowback;

(v) Duration of recovery to the flow line;

(vi) Duration of combustion;

(vii) Duration of venting;

(viii) Specific reasons for venting,

(ix) Documentation for exception from control/recovery.

OR

Photograph of well with REC that contains the following:

(i) Date of photograph;

(ii) Longitude and latitude of the well site embedded within or stored with the photograph (or separate GIS device visible in frame); and

(iii) Picture of equipment for storing or re-injecting recovered liquid, equipment for routing recovered gas to gas flow line, and the completion combustion device connected to and operating at each completion operation.

B. Exemption Category No. 38: Provision c.

- **Non-road engines as defined in 40 CFR § 89.2.**

DOCUMENTS REQUIRED TO BE SUBMITTED TO THE DEPARTMENT TO DEMONSTRATE COMPLIANCE WITH THIS CRITERION.

The owner or operator can submit to the DEP a copy of the certification of conformity from the manufacturer of each non-road engine regulated by EPA under 40 CFR Part 89 showing that each engine is complying with the respective Tier (1 through 4) emissions standards

OR

The owner or operator shall submit a statement to the Department identifying each non-road engine at the facility that is in compliance with the respective federal emission standards promulgated by EPA under 40 CFR Part 89. The owner or operator must retain a copy of the certification of conformity and submit the certification to the Department upon request.

C. Exemption Category No. 38: Provision d.i.

- **Unconventional wells, wellheads, and associated equipment, provided the applicable exemption criteria specified in paragraph d, subparagraphs i, ii, iii, iv and v of the Category No. 38 exemption criteria are met.**
    - **Within 60 days after the well is put into production, and annually thereafter, the owner/operator will perform a leak detection and repair (LDAR) program that includes either the use of an optical gas imaging camera such as a FLIR camera or a gas leak detector capable of reading methane concentrations in air of 0% to 5% with an accuracy of +/- 0.2% or other leak detection monitoring devices approved by the Department. LDAR is to be conducted on valves, flanges, connectors, storage vessels/storage tanks, and compressor seals in natural gas or hydrocarbon liquids service. Leaks are to be repaired no later than 15 days after leak detections unless facility shutdowns or ordering of replacement parts are necessary for repair of the leaks. The optical gas imaging camera or other Department-approved gas leak detection equipment must be operated in accordance with manufacturer-recommended procedures. For the storage vessel, any leak detection and repair will be performed in accordance with 40 CFR Part 60, Subpart OOOO.**
        - **A leak is considered repaired if one of the following can be demonstrated:**

- **No detectable emissions consistent with Method 21 specified in 40 CFR Part 60, Appendix A;**

- **A concentration of 2.5% methane or less using a gas leak detector and a VOC concentration of 500 ppm or less;**

- **No visible leak image when using an optical gas imaging camera;**

- **No bubbling at leak interface using a soap solution bubble test specified in Method 21; or a procedure based on the formation of bubbles in a soap solution that is sprayed on a potential leak source may be used for those sources that do not have continuously moving parts and that do not have a surface temperature greater than the boiling point or less than the freezing point of the soap solution; or**

- **Any other method approved by the Department.**

- **Leaks, repair methods and repair delays will be recorded and maintained for five years. If a gas leak detector is used, a leak is to be detected by placing the probe inlet at the surface of a component. The Department may grant an extension for leak detection deadlines or repairs upon the receipt of a written request from the owner or operator of the facility documenting the justification for the requested extension.**

1. DOCUMENTS REQUIRED TO BE SUBMITTED TO THE DEPARTMENT TO DEMONSTRATE COMPLIANCE WITH LDAR REQUIREMENTS

(i) The equipment or component, date of leak detection, detection method and measurement data or visual image;

(ii) The number of repairs not completed within 15 days. A list of all equipment or components currently on the "Delay of Repair" list, the date each component was placed on the list, reasons and the scheduled dates of repairs; and

(iii) The number of pieces of equipment or components that could not be repaired and reason, if applicable.

2. RECORDS TO BE MAINTAINED FOR LDAR REQUIREMENTS

Following the first time compliance demonstration, the owner or operator may record and maintain the data for the subsequent annual LDAR requirements in electronic form or written log. The owner or operator needs to maintain the record for leaks, repair methods and repair delays for five years and make available to the Department upon request.

D. Exemption Category No. 38: Provision d.ii.

Storage vessels/storage tanks or other equipment equipped with VOC emission controls achieving emissions reduction of 95% or greater. Compliance will be demonstrated consistent with 40 CFR Part 60, Subpart OOOO or an alternative test method approved by the Department.

1. HOW TO DEMONSTRATE COMPLIANCE WITH THIS PROVISION

VOC emissions from storage tanks may be calculated using generally accepted methods such as direct measurement, modeling programs such as current version of EPA TANKS, ProMax, API E&P Tanks, process simulation software such as HYSIM, HYSIS, WINSIM, PROSIM, or calculation methodologies such as Vazquez-Beggs equation.

Storage vessels/tanks subject to 40 CFR Subpart OOOO must comply with the applicable federal requirements.

Compliance with the exemption criteria for storage vessels may be demonstrated by:

(i) An initial performance test and a periodic performance test as specified in 40 CFR § 60.5413 d)(2) through (10) within 60 months of a previous test;

(ii) If the storage tank is equipped with combustion control device, the owner or operator may submit the performance test results conducted by the device manufacturer. The manufacturer must demonstrate that a specific model of control device achieves the performance requirement of 95% or more VOC control by conducting a performance test as specified in 40 CFR § 60.5413 (d)(2) through (10).

(iii) Maintaining daily average control device parameters above (or below) the minimum (or maximum) level established during the performance test;

(iv) Preparing a site-specific monitoring plan for a continuous monitoring system; and

(v) Conducting initial and annual inspections of covers and closed vent systems for leaks or defects.

2. DOCUMENTS REQUIRED TO BE SUBMITTED TO THE DEPARTMENT TO DEMONSTRATE COMPLIANCE WITH THE 95% VOC REDUCTION REQUIREMENT FROM STORAGE VESSELS.

(i) An identification of each affected storage vessel.

(ii) Location of each storage vessel with latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(iii) Documentation of the VOC emission rate determination using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production.

(iv) Results of the performance tests performed as specified in 40 CFR § 60.5413 (d)(2) through (10).

3. DOCUMENTS REQUIRED TO BE SUBMITTED TO THE DEPARTMENT TO DEMONSTRATE COMPLIANCE WITH THE 95% VOC REDUCTION REQUIREMENT FROM OTHER EQUIPMENT

(i) An identification of each affected equipment.

(ii) Documentation of the VOC emission rate determination using a generally accepted model or calculation methodology.

(iii) Results of the performance tests performed as specified in 40 CFR part 60 Subpart OOOO § 60.5413 (d)(2) through (10).

4. DOCUMENTS REQUIRED TO BE SUBMITTED TO THE DEPARTMENT TO DEMONSTRATE COMPLIANCE WITH THE 95% VOC REDUCTION REQUIREMENT FROM TANKER TRUCK LOAD-OUT

(i) An identification of each affected equipment.

(ii) Documentation of the VOC emission rate determination using a generally accepted model or calculation methodology.

(iii) Results of the performance tests performed as specified in MACT-level annual leak test or NSPS-level annual test (3 inches pressure change) or alternate test methods as approved by the Department.

E. Exemption Category No. 38: Provision d.iii.

Combined VOC emissions from all the sources at the facility less than 2.7 tons on a 12-month rolling basis. If the VOCs include HAPs, the HAP exemption criteria in this paragraph will be met. Compliance with this criterion is to be determined using any generally accepted model or calculation methodology. Combined HAP emissions [not including Polychlorinated Biphenyls (PCBs), Chromium (Cr), Mercury (Hg), Lead (Pb), Polycyclic Organic Matter (POM), Dioxins and Furans] at the facility less than 1000 lbs of a single HAP or one ton of a combination of HAPs

in any consecutive 12-month period. The emission criteria do not include emissions from sources which are approved by the Department in plan approvals, or the general plan approvals/general operating permits at the facility and the emissions from sources meeting the exemption criteria in subparagraphs i, ii, and iv.

DOCUMENTS REQUIRED TO BE SUBMITTED TO THE DEPARTMENT TO DEMONSTRATE COMPLIANCE WITH THIS CRITERION

The owner or operator shall submit to the Department detailed VOC and HAP emissions calculations using generally accepted models or calculation methodologies for the estimation of emissions include, but not limited to, vendors' data, direct measurement, modeling programs such as current version of EPA TANK, ProMax, API E&P Tanks, process simulation software, source test data from identical sources or EPA emission factors.

F. Exemption Category No. 38: Provision d.ivA-D.

Flaring activities as outlined below:

- **Flaring used at exploration wells to determine whether oil and/or gas exists in geological formations or to appraise the physical extent, reserves and likely production rate of an oil or gas field.**
- **Flaring used for repair, maintenance, emergency or safety purposes.**
- **Flaring used for other operations at a wellhead or facility to comply with 40 CFR Part 60, Subpart OOOO requirements.**
- **Enclosed combustion device including enclosed flare will be used for all permanent flaring operations at a wellhead or facility. These flaring operations will be designed and operated in accordance with the requirements of 40 CFR § 60.18.**

DOCUMENTS REQUIRED TO BE SUBMITTED TO THE DEPARTMENT TO DEMONSTRATE COMPLIANCE WITH THIS CRITERION

The owner or operator shall submit the document (manufacture's certification, specification sheet, etc) showing that all permanent flares are enclosed and are designed and operated in accordance with 40 CFR § 60.18.

G. Exemption Category No. 38: Provision d.v.

Combined NOx emissions from the stationary internal combustion engines at wells, and wellheads less than 100 lbs./hr., 1000 lbs./day, 2.75 tons per ozone season (the period beginning May 1 of each year and ending on September 30 the same year), and 6.6 tons per year on a 12-month rolling basis. The emissions criteria do not include emissions from sources which are approved by plan approvals or general permits at the facility.

DOCUMENTS REQUIRED TO BE SUBMITTED TO THE DEPARTMENT TO DEMONSTRATE COMPLIANCE WITH THIS CRITERION

The owner or operator shall submit to the Department detailed calculations for NOx emissions from each source using any generally accepted model or calculation methodology, including, but not limited to, vendors' data, source test data from identical sources, or EPA emission factors.

Comparison of Air Emission Standards for the Oil & Gas Industry

(Well Pad Operations, Natural Gas Compressor Stations, and Natural Gas Processing Facilities)

The Pennsylvania Department of Environmental Protection issued a General Permit, General Plan Approval and/or General Operating Permit (BAQ-GPA/GP-5) to authorize the construction, modification, and/or operation of natural gas compression and/or natural gas processing facilities. Plan Approval and Operating Permit Exemption Category #38 (Well Pad Operations) was amended on August 10, 2013.

The Center for Sustainable Shale Development (CSSD) is an independent nonprofit organization based in Pittsburgh, Pennsylvania. The Center provides a forum for a diverse group of stakeholders to share expertise with the common objective of developing solutions and serving as a center of excellence for shale gas development. CSSD's mission is to support continuous improvement and innovative practices through performance standards and third-party certification. CSSD has developed initial performance standards for operators engaged in unconventional exploration, development, and gathering activities including site construction, drilling, hydraulic fracturing and production in the Appalachian Basin. These standards represent consensus on what is achievable and protective of human health and the environment.

Colorado Department of Public Health and Environment, Air Quality Control Commission has promulgated air emissions regulations 3, 6, & 7 (adopted 23-Feb-2014) impacting oil and gas (O&G) exploration and production (E&P) activities in Colorado.

EPA has promulgated New Source Performance Standards at 40 CFR Part 60, Subpart OOOO (Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution).

West Virginia and **Ohio** have issued General Air Permits for Natural Gas Production facilities.

This document provides a comparison of the requirements in these air standards. The information highlighted in blue was compiled by CSSD.

Pennsylvania Department of Environmental Protection, Bureau of Air Quality
5/23/2014

Item	Pennsylvania	CSSD Performance Standard	Federal	Colorado	Ohio	West Virginia
Well Site	Exemption Category No. 38[1] • Requires compliance with NSPS requirements in 40 CFR Part 60, Subpart OOOO. • Beginning 10/15/12 - No venting allowed – must capture and direct flowback emissions to a completion combustion device, except in conditions that may result in a fire hazard or explosion. • Beginning on 1/1/15 – direct all pipeline-quality gas during completion of development wells and re-completion or workover of any well into a pipeline for sales. • Open Flaring is only allowed under the following circumstances: ○ used at exploration wells to determine whether oil and/or gas exists in geological formations or to appraise the physical extent, reserves and likely production rate of an oil or gas field. ○ Flaring used for repair, maintenance, emergency or safety purposes. ○ Flaring used for other operations at a wellhead or facility to comply with 40 CFR	Performance Standard No. 9 • Beginning on 1/1/14 – direct all pipeline-quality gas during completion of development wells and re-completion or workover of any well into a pipeline for sales. • No venting allowed – must be flared in accordance with CSSD Performance Standard No. 10. • Acceptable reasons for flaring – low content of flammable gas and safety reasons. • Unacceptable reasons for flaring – i) lack of pipeline connection except for exploratory or extension wells; ii) inadequate water disposal capacity; iii) inadequate or lack of flowback equipment or operating personnel.	NSPS Subpart OOOO • Beginning 10/15/12: ○ Must capture and direct flowback emissions to a completion combustion device, except in conditions that may result in a fire hazard or explosion.[2] • Beginning 1/1/15: ○ REC equipment required for all wells besides those classified as wildcat, delineation or low pressure.[3] ○ Salable quality gas must be routed to the gas flow line "as soon as practicable."[4] ○ Emissions that cannot be directed to the gas flow must be directed to a completion combustion device (*e.g.*, flare) with a continuous ignition source except in conditions that may result in a fire hazard or explosion.[5] ○ General duty to safely maximize resource recovery and minimize releases to the atmosphere during flowback and subsequent recovery.[6]	Regulation Nos. 6 & 7: • Requires compliance with NSPS requirements in 40 CFR Part 60, Subpart OOOO. • If a combustion device is used to control emissions of VOCs and other hydrocarbons, it shall be enclosed. • Alternative emissions control equipment shall qualify as air pollution control equipment, and may be used if the Division approves the equipment, device or process.	Current • No state-specific REC requirements in addition to NSPS Subpart OOOO. • Flaring required except for gas releases by a properly functioning relief device and gas released by controlled venting for testing, blowing down and cleaning out wells.[7] Proposed • Natural Gas Completion Permit-by-Rule[8] – requires compliance with NSPS Subpart OOOO.	• No state-specific REC requirements in addition to NSPS Subpart OOOO • Compliance with NSPS Subpart OOOO requirements is required by General Permit G70-A9; (however, permit is not required to be obtained prior to well completion activities.)[10]

[1] 'Pennsylvania's Air Quality Permit Exemptions
[2] 40 C.F.R. § 60.5375(a)
[3] 40 C.F.R. § 60.5375(a)
[4] 40 C.F.R. § 60.5375(a)(2)
[5] 40 C.F.R. § 60.5375(a)(3)
[6] 40 C.F.R. § 60.5375(a)(4)
[7] Ohio Admin. Code § 1501:9-9-05(B)
[8] Ohio's Draft Natural Gas Completion Draft Permit-by-Rule

Item	Pennsylvania	CSSD Performance Standard	Federal	Colorado	Ohio	West Virginia
	Part 60, Subpart OOOO requirements. • Enclosed combustion device including enclosed flare must be used for all permanent flaring operations at a wellhead or facility. These flaring operations will be designed and operated in accordance with the requirements of 40 CFR § 60.18.					

Flaring	Exemption Category No. 38 [11]
	
	• Flaring during completions as allowed by NSPS Subpart OOOO.
	
	Post Completion Requirements:
	
	• Enclosed flare (Raised/elevated flares or engineered combustion device) must be used for permanent installations.
	
	• All permanent enclosed flaring operations must be designed and operated in accordance with 40 CFR § 60.18.
		Performance Standard No. 10
		
		• Raised/elevated flares or engineered combustion device with a reliable continuous ignition source.
		
		• 98% destruction efficiency.
		
		• Development well: flaring no more than 14-days (for life of well).
		
		• Exploratory/Extension wells: Flaring no more than 30-days (for life of well).
		
		• No visible emissions from flares except
			NSPS Subpart OOOO
			
			• Completion combustion devices (*e.g.* flares) are required to have a continuous ignition source. [12]
				Regulation No. 7:
				
				• If a combustion device is used to control emissions of VOCs and other hydrocarbons, it shall be enclosed.
				
				• Have no visible emissions during normal operations
				
				• Be designed so than that an observer can determine whether it is operating properly.
				
				• Auto-igniters: All combustion devices used to control emissions of hydrocarbons must be equipped with and operate an auto-
					Current
					
					• Requires "properly functioning relief device"[13]
					
					Proposed Natural Gas Completion Permit-by-Rule[14]
					
					• Emissions limitations for completion operations:
					  ○ 34 tons/yr VOCs.
					  ○ 1.7 tons/yr NOx.
					  ○ 9.3 tons/yr CO.
					  ○ 0.82 tons/yr HAP.
						• "Temporary" flaring allowed for 30-days before a permit is required.[15]
						  ○ 20% opacity limitation and PM emissions limit set according to a formula[16]
						
						• General Permit G70A: 20% opacity limitation

[9] WVDEP General Permit G70-A, Section 5.1
[10] WVDEP Response to Public Comment #33 on General Permit G70-A
[11] Pennsylvania's Air Quality Permit Exemptions
[12] 40 C.F.R § 60.5375(a)(3)
[13] Ohio Admin. Code § 1501:9-9-05(B)
[14] Ohio's Proposed Natural Gas Completion Permit-by-Rule
[15] W. Va. Code R. § 45-6-6.1a
[16] W. Va. Code R. § 45-6-4.1, 4.3

Item	Pennsylvania	CSSD Performance Standard	Federal	Colorado	Ohio	West Virginia
	• Open Flaring is only allowed under the following circumstances: ○ Flaring used at exploration wells to determine whether oil and/or gas exists in geological formations or to appraise the physical extent, reserves and likely production rate of an oil or gas field. ○ Flaring used for repair, maintenance, emergency or safety purposes. ○ Flaring used for other operations at a wellhead or facility to comply with 40 CFR Part 60, Subpart OOOO requirements. • Opacity is limited to 20% or greater for an aggregated 3 min period in any 1 hour, but cannot be equal to or greater than 60% opacity at any time.	for periods not to exceed a total of five minutes during any two consecutive hours.		igniter as follows: ○ All combustion devices installed on or after May 1, 2014, must be equipped with an operational auto-igniter upon installation of the combustion device. ○ All combustion devices installed before May 1, 2014, must be equipped with an operational auto-igniter by or before May 1, 2016, or after the next combustion device planned shutdown, whichever comes first. • Alternative emissions control equipment shall qualify as air pollution control equipment, and may be used if the Division approves the equipment, device or process.	GP-12.1[19] Enclosed or Open Flare(s)/Combustion Device(s) with a maximum combined capacity heat input of no more than 250 MMBtu/hr and operated at no more than 10 MMBtu per hour combined heat input from all the sources vented to the combustion device(s), except during an emergency. ○ For VOC and where applicable, compliance with the applicable control requirements of 40 CFR Part 60, Subpart OOOO, by having a designed minimum control efficiency of 95% for an enclosed flare/combustor. ○ Carbon monoxide (CO) emissions shall not exceed 1.35 tons per month averaged over a 12-month rolling period. ○ Nitrogen Oxide (NOx) emissions shall not exceed 0.25 ton per month averaged over a 12-month rolling period. ○ Sulfur Dioxide (SO2) emissions shall not exceed 0.15 ton per month averaged over a 12-month rolling period. GP-12.2[20] Enclosed or Open Flare(s)/Combustion Device(s) with a maximum combined capacity heat input of no more than 250 MMBtu/hr and operated at no more than 32 MMBtu per hour combined heat input from all the sources vented to the combustion device(s), except during an emergency.	and PM emissions limit set according to a formula.[17] • However, permit is not required to be obtained prior to well completion activities.[18]

[19] Ohio General Permit 12.1, Condition 4
[20] Ohio General Permit 12.2, Condition 4
[17] WVDEP General Permit G70-A, Section 5.1.5
[18] WVDEP Response to Public Comment #33 on General Permit G70-A

Item	Pennsylvania	CSSD Performance Standard	Federal	Colorado	Ohio	West Virginia
					○ For VOC and where applicable, compliance with the applicable control requirements of 40 CFR Part 60, Subpart OOOO, by having a designed minimum control efficiency of 95% for an enclosed flare/combustor. ○ Carbon monoxide (CO) emissions shall not exceed 4.32 tons per month averaged over a 12-month rolling period. ○ Nitrogen Oxide (NOx) emissions shall not exceed 0.79 ton per month averaged over a 12-month rolling period. ○ Sulfur Dioxide (SO2) emissions shall not exceed 0.48 ton per month averaged over a 12-month rolling period.	
Diesel Nonroad Drilling Rig Engines	• States including Pennsylvania are precluded from establishing any emissions limitations other than those required by 40 CFR Part 89. • Non-road engines are exempt from permitting requirements under Exemption Category No. 38.[21] • All non-road engines must comply with federal emission standards found in 40 CFR Part 89, Subpart B or 40 CFR Part 1039, Subpart B, based upon the engine's model year. • Only ultra-low sulfur diesel fuel will be available.	Performance Standard No. 11 • Meet EPA Tier 2 standards by March 20, 2013. • 25% of owner/operator engine utilization (hp) meeting EPA Tier 4 standards for PM by March 20, 2015. • 75% of owner/operator engine utilization (hp) meeting EPA Tier 4 standards for PM by September 24, 2015. • 95% of owner/operator engine utilization meeting EPA Tier 4 standards for PM by September 24, 2016. • Use ultra-low sulfur diesel (15ppm of	• U.S. EPA regulates emissions from non-road diesel engines according to varying "tiered" levels based on the engine's manufacturing date.[22] • Starting in 2010, diesel produced for use in non-road engines required to meet ultra-low sulfur (15 ppm of sulfur) requirement.[23]	• States are precluded from establishing any emissions limitations other than those required by 40 CFR Part 89.	• States are precluded from establishing any emissions limitations other than those required by 40 CFR Part 89.	• States are precluded from establishing any emissions limitations other than those required by 40 CFR Part 89.

[21] Pennsylvania's Air Quality Permit Exemptions
[22] 40 C.F.R. Part 89; 40 C.F.R. Part 1039
[23] 40 C.F.R. Part 80

Item	Pennsylvania	CSSD Performance Standard	Federal	Colorado	Ohio	West Virginia
		sulfur) at all times.				
Diesel Nonroad Fracturing Pump Engines	• States including Pennsylvania are precluded from establishing any emissions limitations other than those required by 40 CFR Part 89. • Non-road engines are exempt from permitting requirements under Exemption Category No. 38. • All non-road engines must comply with federal emission standards found in 40 CFR Part 89, Subpart B or 40 CFR Part 1039, Subpart B based upon the engine's model year. • Only ultra-low sulfur diesel fuel will be available.	Performance Standard No. 11.1 • Meet EPA Tier 2 standards by March 20, 2014. • 25% of owner/operator engine utilization (hp) meeting EPA Tier 4 standards for PM by September 24, 2015/ March 20, 2016. • 75% of owner/operator engine utilization (hp) meeting EPA Tier 4 standards for PM by September 24, 2016. • 95% of owner/operator engine utilization meeting EPA Tier 4 standards for PM by September 24, 2017. • Use ultra-low sulfur diesel (15ppm of sulfur) at all times.	• U.S. EPA regulates emissions from non-road diesel engines according to varying "tiered" levels based on the engine's manufacturing date24 • Starting in 2010, diesel produced for use in non-road engines required to meet ultra-low sulfur (15 ppm of sulfur) requirement.[25]	• States are precluded from establishing any emissions limitations other than those required by 40 CFR Part 89.	• States are precluded from establishing any emissions limitations other than those required by 40 CFR Part 89.	• States are precluded from establishing any emissions limitations other than those required by 40 CFR Part 89.
Diesel Heavy-Duty Vehicle Fracturing Pump Engines	• States including Pennsylvania are precluded from establishing any emissions limitations other than those required by 40 CFR Part 86. • Heavy duty vehicle engines are exempt from permitting requirements under Exemption Category No. 38. • All Heavy Duty vehicle engines must comply with federal emission standards found in 40 CFR Part 86. • Only ultra-low sulfur diesel fuel will be available.	Performance Standard No. 11.2 • 50% of engines meeting EPA 2007 and Later Model Year Highway Heavy-Duty Vehicles and Engines emissions standards for PM by September24, 2017. • 80% of engines meeting EPA 2007 and Later Model Year Highway Heavy-Duty Vehicles and Engines emissions standards for PM by September 24, 2014. • Use ultra-low sulfur diesel (15ppm of sulfur) at all times.	• U.S. EPA regulates engine emissions from highway heavy-duty vehicles based on the vehicle's model year. • Starting in 2006, highway diesel fuel required to meet ultra-low sulfur (15 ppm of sulfur) requirement.	• States are precluded from establishing any emissions limitations other than those required by 40 CFR Part 89.	• States are precluded from establishing any emissions limitations other than those required by 40 CFR Part 89.	• States are precluded from establishing any emissions limitations other than those required by 40 CFR Part 89.

[24] 40 C.F.R. Part 89; 40 C.F.R. Part 1039
[25] 40 C.F.R. Part 80

Item	Pennsylvania	CSSD Performance Standard	Federal	Colorado	Ohio	West Virginia
Existing Compressor Engines	Previous Exemption Category No. 38 • Existing compressor engines (those installed prior to August 10, 2013) – exempt from any permitting or emission limitation requirements if less than 100 hp. Previous GP-5 • Prior to February 2013 - existing compressor engines greater than or equal to 100 hp and less than 1500 hp were subject to the previous GP-5 emissions limitations: o 2.0 g/hp-hr NOx. o 2.0 g/hp-hr CO. o 2.0 g/hp-hr VOCs. • **Emission test results** indicate that the existing compressor engines authorized under the previous GP-5 are generally meeting the CCSD performance standard of 1.5 g/bhp-hr of NOx.	Performance Standard No. 12 • By March 20, 2014 – 1.5 g/hphr NOx emission limitation for existing compressor engines greater than 100 hp. o CO – None o VOC – None	NSPS Subpart JJJJ (Standards of Performance for Stationary Spark Ignition Internal Combustion Engines) • Applies to constructed, reconstructed, and modified engines after June 12, 2006.[26] • Emissions limitations for engines manufactured between 2007/2008 and 2010/2011 greater than 100 hp:[27] o 2.0 g/hp-hr for NOx. o 4.0 g/hp-hr for CO. o 1.0 g/hp-hr for VOCs. • Compressor engines are also subject to the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines (RICE) at 40 C.F.R. 63, Subpart ZZZZ (*i.e.*, the "RICE MACT")[28]	Existing Natural Gas Fired Reciprocating Internal Combustion Engines: Rich Burn Reciprocating Internal Combustion Engines: • Rich Burn Engines greater than 500 horsepower, constructed or modified before February 1, 2009 - shall install NSCR and an air fuel controller by July 1, 2010. • Any rich burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $ 5,000 per ton of combined volatile organic compound and nitrogen oxides emission reductions (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section XVII.E.3.a. Lean Burn Reciprocating Internal Combustion Engines: • All lean burn reciprocating internal combustion engines rated greater than 500 horsepower - install and operate an oxidation catalyst by July 1, 2010. • Any lean burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $ 5,000 per ton of volatile organic compound emission reduction (this value shall be adjusted for future applications according to the current		Natural Gas Compressor Station General Permit Number G33-A[29] Engines over 100 HP - compliance with NSPS Subpart JJJJ.

[26] 40 C.F.R. § 60.4230
[27] 40 C.F.R. Part 60, Subpart JJJJ, Table 1
[28] 40 C.F.R. Part 63, Subpart ZZZZ
[29] WVDEP General Permit G33-A, Section 6.0

<table>
<tr><th>Item</th><th>Pennsylvania</th><th>CSSD Performance Standard</th><th>Federal</th><th>Colorado</th><th>Ohio</th><th>West Virginia</th></tr>
<tr><td></td><td></td><td></td><td></td><td>day consumer price index) is exempt from complying with the requirement to install an oxidation catalyst.</td><td></td><td></td></tr>
<tr><td>"New" Lean-Burn Compressor Engines</td>
<td>Exemption Category No. 38 (Compressor Engines at the Wellpad)[30]
• Lean-Burn compressor engines at the wellpad (those installed on or after August 10, 2013) are exempt from permitting requirements provided that:
o NOx emissions from stationary internal combustion engines at the wells, and wellheads are less than 100 lbs/hr, 1000 lbs/day, 2.75 tons per ozone season (May 1 to September 30); and 6.6. tons per year on a 12-month rolling basis.
o VOC emissions from facility is less than 2.7 tpy, VOC from facility is exempted. If the VOCs include HAPs, the HAP exemption criteria in this paragraph will be met. Combined HAP emissions at the facility less than 1000 lbs of a single HAP or one ton of a combination of HAPs in any consecutive 12-month period.
o If the exemption criteria cannot be met, then a case-by-case plan approval is required.

GP-5 (Compressor Engines at Natural Gas Compression and/or Processing Facilities) (Feb. 2013)
• The facility emissions are limited to non-major emission thresholds. (Synthetic Minor)</td>
<td>Performance Standard No. 12.1
• Emissions limitations for new, purchased, replacement, reconstructed, or relocated lean-burn engines greater than 100 hp:
o 0.5 g/hp-hr NOx.
o 2.0 g/hp-hr CO.
o 0.7 g/hp-hr VOCs.
o Formaldehyde – None
o HAPS – No facility wide limit</td>
<td>NSPS Subpart JJJJ (Standards of Performance for Stationary Spark Ignition Internal Combustion Engines)
• Emissions limitations for engines manufactured on or after 2010/2011 greater than 100 hp engine models (depending on engine size)[31]:
o 1.0 g/hp-hr for NOx.
o 2.0 g/hp-hr for CO.
o 0.7 g/hp-hr for VOCs.

Compressor engines are also subject to the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines (RICE) at 40 C.F.R. 63, Subpart ZZZZ (i.e., the "RICE MACT")[32]</td>
<td>• No emission standards for engines rated less than 100 HP

Regulation No. 7:
• Actual emissions from natural gas fired reciprocating internal combustion engines shall not exceed the emission performance standards in table below as expressed in units of grams per horsepower-hour (g/hp-hr)
<table>
<tr><td>Maximum Engine HP</td><td>Construction or Relocation Date</td><td colspan="3">Emission Standards is g/hp-hr</td></tr>
<tr><td></td><td></td><td>NOx</td><td>CO</td><td>VOC</td></tr>
<tr><td>< 100 HP</td><td>Any</td><td>NA</td><td>NA</td><td>NA</td></tr>
<tr><td rowspan="2">≥100 HP and < 500 HP</td><td>On or after January 1, 2008</td><td>2.0</td><td>4.0</td><td>1.0</td></tr>
<tr><td>On or after January 1, 2011</td><td>1.0</td><td>2.0</td><td>0.7</td></tr>
<tr><td rowspan="2">≥500 Hp</td><td>On or after July 1, 2007</td><td>2.0</td><td>4.0</td><td>1.0</td></tr>
<tr><td>On or after July 1, 2010</td><td>1.0</td><td>2.0</td><td>0.7</td></tr>
</table>
o Formaldehyde – None</td>
<td>Oil and Gas Well-Site Production Operations, General Permit 12
• Engines must comply with NSPS Subpart JJJJ standards.
• Specific emissions limitations:
o 20% opacity, 6-min average.
o Particulate Emissions (PE):
0.310 lb/MMBtu for engines ≤ 600 hp.
0.062 lb/MMBtu for engines > 600 hp.
o 2.6 tons of SO2/year.
• Total combined engine power less than or equal to 1,300 hp:
o 2.0 g/hp-hr NOx or 160 ppmvd at 15% O2 for engines ≥ 100 hp.
o 4.0 g/hp-hr CO or 540 ppmvd at 15% O2 for engines ≥ 100 hp.
o 1.0 g/hp-hr VOCs or 86 ppmvd at 15% O2 for engines ≥ 100 hp.
• Total combined engine power greater than 1,300 hp:
o 1.0 g/hp-hr NOx /or 82 ppmvd at 15% O2 for engines ≥ 100 hp.
o 2.0 g/hp-hr CO/or 270 ppmvd at 15% O2 for engines ≥ 100 hp.</td>
<td>Natural Gas Production Facility Class II General Permit G70-A

Requires compliance with NSPS Subpart JJJJ.[33]</td></tr>
</table>

30 Pennsylvania's Air Quality Permit Exemptions
31 40 C.F.R. Part 60, Subpart JJJJ, Table 1
32 40 C.F.R. Part 63, Subpart ZZZZ
33 WVDEP General Permit G70-A, Section 13

<table>
<tr><th>Item</th><th>Pennsylvania</th><th>CSSD Performance Standard</th><th>Federal</th><th>Colorado</th><th>Ohio</th><th>West Virginia</th></tr>
<tr>
<td></td>
<td>Natural gas fired lean burn less than 100 hp
2.0 g/hp-hr for NOx.
2.0 g/hp-hr for CO.
Natural gas lean burn greater than 100 hp and less than or equal to 500 hp
1.0 g/hp-hr for NOx.
2.0 g/hp-hr for CO.
0.7 g/hp-hr for non-methane/non-ethane hydrocarbons (except formaldehyde).
Natural gas lean burn greater than 500 hp
0.5 g/hp-hr for NOx.
93% reduction for CO or 47ppm@15% oxygen.
0.25 g/hp-hr for non-methane/non-ethane hydrocarbons (except formaldehyde).
0.05 g/hp-hr for formaldehyde.</td>
<td></td>
<td></td>
<td></td>
<td>0.7 g/hp-hr VOCs or 60 ppmvd at 15% O2 for engines ≥ 100 hp.</td>
<td></td>
</tr>
<tr>
<td>“New” Rich-Burn Compressor Engines</td>
<td>Exemption Category No. 38 (Compressor Engines at the Wellpad)[34]
Rich Burn compressor engines at the wellpad (those installed on or after August 10, 2013) exempt from permitting where:
NOx emissions from stationary internal combustion engines at the wells, and wellheads are less than 100 lbs/hr, 1000 lbs/day, 2.75 tons per ozone season (May 1 to September 30); and 6.6 tons per year on a 12-month rolling basis.
VOC emissions less than 2.7 tpy, VOCs from facility are exempted. If the VOCs include HAPs, the HAP exemption criteria in this paragraph will be</td>
<td>Performance Standard No. 12.2
Emissions limitations for new, purchased, replacement, reconstructed, or relocated rich-burn engines greater than 100 hp:
0.3 g/hp-hr NOx.
2.0 g/hp-hr CO.
0.7 g/hp-hr VOCSs.
Formaldehyde - None</td>
<td>NSPS Subpart JJJJ (Standards of Performance for Stationary Spark Ignition Internal Combustion Engines)
Emissions limitations for engines manufactured on or after 2010/2011 greater than 100 hp engine models (depending on engine size):[35]
1.0 g/hp-hr for NOx.
2.0 g/hp-hr for CO.
0.7 g/hp-hr for VOCs.
Compressor engines are also subject to the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines (RICE) at 40 C.F.R. 63, Subpart ZZZZ (i.e., the “RICE</td>
<td>Regulation No. 7:
Actual emissions from natural gas fired reciprocating internal combustion engines shall not exceed the emission performance standards in table below as expressed in units of grams per horsepower-hour (g/hp-hr)
<table>
<tr><td>Maximum Engine HP</td><td>Construction or Relocation Date</td><td colspan="3">Emission Standards is g/hp-hr</td></tr>
<tr><td></td><td></td><td>NOx</td><td>CO</td><td>VOC</td></tr>
<tr><td>< 100 HP</td><td>Any</td><td>NA</td><td>NA</td><td>NA</td></tr>
<tr><td>≥100 HP and < 500 HP</td><td>On or after January 1, 2008</td><td>2.0</td><td>4.0</td><td>1.0</td></tr>
</table></td>
<td>Oil and Gas Well-Site Production Operations, General Permit 12

Engines must comply with NSPS Subpart JJJJ standards.[37]
Specific emissions limitations:[38]
20% opacity, 6-min average.
Particulate Emissions (PE):
0.310 lb/MMBtu for engines ≤ 600 hp.
0.062 lb/MMBtu for engines > 600 hp.
2.6 tons of SO_2/year.
Total engine power less than or equal to 1,300 hp:</td>
<td>Natural Gas Production Facility Class II General Permit G70-A

Compliance with NSPS Subpart JJJJ.[40]</td>
</tr>
</table>

[34] Pennsylvania's Air Quality Permit Exemptions

[35] 40 C.F.R. Part 60, Subpart JJJJ, Table 1

<table>
<tr><th>Item</th><th>Pennsylvania</th><th>CSSD Performance Standard</th><th>Federal</th><th>Colorado</th><th>Ohio</th><th>West Virginia</th></tr>
<tr>
<td></td>
<td>met. Combined HAP emissions at the facility less than 1000 lbs of a single HAP or one ton of a combination of HAPs in any consecutive 12-month period.

o If the exemption criteria cannot be met, then a case-by-case plan approval is required.

<u>Coverage under GP-5 (Rich-Burn Compressor Engines at Natural Gas Compression and/or Processing Facilities) (Feb. 2013)</u>

• The facility emissions are limited to non-major emission thresholds. (Synthetic Minor)

• Natural gas fired rich burn engines less than or equal to 100 hp:
• 2.0 g/hp-hr NOx.
• 2.0 g/hp-hr CO.

• Natural gas rich burn engines greater than 100 hp and less than or equal to 500 hp:
• 0.25 g/hp-hr NOx.
• 0.30 g/hp-hr CO;
• 0.2 g/hp-hr for non-methane/non-ethane hydrocarbons (except formaldehyde).

• Natural gas rich burn engines greater than 500 hp:
• 0.20 g/hp-hr NOx.
• 0.30 g/hp-hr CO.
• 0.20 g/hp-hr for non-methane/non-ethane hydrocarbons (except formaldehyde).
• 76% reduction for formaldehyde or 2.7 ppmvd @ 15% oxygen</td>
<td></td>
<td>MACT")[36]</td>
<td><table>
<tr><td></td><td>On or after January 1, 2011</td><td>1.0</td><td>2.0</td><td>0.7</td></tr>
<tr><td>≥500 Hp</td><td>On or after July 1, 2007</td><td>2.0</td><td>4.0</td><td>1.0</td></tr>
<tr><td></td><td>On or after July 1, 2010</td><td>1.0</td><td>2.0</td><td>0.7</td></tr>
</table>
o Formaldehyde - None</td>
<td>▪ 2.0 g/hp-hr NOx or 160 ppmvd at 15% O_2 for engines ≥ 100 hp.

▪ 4.0 g/hp-hr CO or 540 ppmvd at 15% O_2 for engines ≥ 100 hp.

▪ 1.0 g/hp-hr VOCs or 86 ppmvd at 15% O_2 for engines ≥ 100 hp.

o Total engine power greater than 1,300 hp:[39]

• 1.0 g/hp-hr NOx /or 82 ppmvd at 15% O_2 for engines ≥ 100 hp.

• 2.0 g/hp-hr CO/or 270 ppmvd at 15% O_2 for engines ≥ 100 hp.

• 0.7 g/hp-hr VOCs or 60 ppmvd at 15% O_2 for engines ≥ 100 hp.</td>
<td></td>
</tr>
</table>

[37] Ohio GP-12, at pp. 12-14
[38] Ohio GP-12, at pp. 12-14
[40] WVDEP General Permit G70-A, Section 13
[36] 40 C.F.R. Part 63, Subpart ZZZZ
[39] The total combined total engine horsepower must also be no more than 1,800 hp for the site in order to qualify for Ohio's GP-12. *See* Ohio GP-12, at pp. 12. Additionally, where the total combined engine power exceeds 1,300 hp the engines must have a manufacturing date of no earlier than January 1, 2011 for engines less than 500 HP or no earlier than July 1, 2010 for engines 500 hp or greater. *Id*.

Item	Pennsylvania	CSSD Performance Standard	Federal	Colorado	Ohio	West Virginia

Storage Vessels	Exemption Category No. 38[41]:
	• Storage vessels/storage tanks at the well pad are exempt from permit requirements if they are equipped with VOC emission controls achieving emission reduction of 95% or greater.
	• Storage tanks at the well pad can qualify for the exemption if combined VOC emissions from all the sources at the facility are less than 2.7 tons on a 12-month rolling basis. Combined HAP emissions at the facility must be less than 1000 lbs of a single HAP or one ton of a combination of HAPs in any consecutive 12-month period in order to qualify for the exemption. If the VOCs emissions include HAPs, this HAP exemption criteria is met.
	• No de minimis emission threshold per tank as allowed in NSPS Subpart OOOO (i.e., must reduce storage tank/storage vessel VOC emissions by 95% if combined VOC emissions from storage vessels/storage tanks are above 2.7 tpy in order to qualify for exemption).
	• Compliance with above criteria ensures compliance with NSPS Subpart OOOO.
	GP-5
	• The owner or operator of each storage vessel / storage tank shall also comply with the applicable requirements specified in 40 CFR Part 60, Subparts Kb and OOOO and 40 CFR Part 63, Subpart HH (relating to national emission standards
		Performance Standard No. 13
		• By October 15, 2013 – all existing or new individual storage vessels at the wellpad with VOC emissions equal to or greater than 6 tpy must install controls to achieve at least a 95% reduction in VOC emissions.
			NSPS Subpart OOOO
			• "New" Group 1 storage vessels (constructed, modified, or reconstructed after August 23, 2011 and before April 12, 2013) that have potential VOC emissions equal to or greater than 6 tons per year (tpy) - at least a 95% reduction in VOC emissions by April 15, 2015.[42]
			• "New" Group 2 storage vessels (constructed, modified, or reconstructed after April 12, 2013) that have potential VOC emissions equal to or greater than 6 tons per year (tpy) - at least a 95% reduction in VOC emissions by April 15, 2014 or within 60-days of startup (whichever is later).[43]
			• 6 tpy VOC determination may take into account enforceable limits in an operating permit or other requirement established under a Federal, State, local or tribal authority.[44]
			• Emissions from a storage vessel that are recovered and routed to a process through a vapor recovery unit (VRU) can be excluded from the 6 tpy VOC determination provided certain requirements are met.[45]
			• Control devices (installed to achieve the 95% reduction in VOC emissions discussed above) may be removed if emissions from the storage vessel have been below 4 tpy on an uncontrolled basis for 12
				Regulation No. 7:
				• Construction permits are now required for all crude oil storage tanks (previously, tanks with capacity < 40,000 gallons were exempt)
				• Operating permits are now required for all crude oil storage tanks (previously, tanks with capacity < 40,000 gallons were exempt)
				• For tanks projected to have > 1.5 tons VOC emissions in first 90 days of operation
				  ○ Emissions controls must be installed at date of first operation and must have 95% (98% if combustion device used) efficiency
				  ○ Controls can be removed after 90 days if VOC emissions are projected to be <6 tons per year
				• Storage tank controls after 90 days:
				• For tanks with VOC emissions less than 20 TPY and equal to or greater than 6 TPY – 95% control efficiency (98% if a combustion device is used).
				• For tanks with VOC emissions greater than 20 TPY – 95% control efficiency.
				• AVO inspections of tanks and associated equipment as frequent as every 7 days and at least every 31 days.
					Oil and Gas Well-Site Production Operations, General Permit 12
					• Total VOC emissions from all tanks combined at the site (including breathing losses, tank working losses, flash losses and truck loading losses) may not exceed 51.3 tons per rolling 12-month period.[48]
						Natural Gas Production Facility Class II General Permit G70-A
						• Requires compliance with NSPS Subpart OOOO[49]

[41] Pennsylvania's Air Quality Permit Exemptions
[42] 40 C.F.R. § 60.5395(b)
[43] 40 C.F.R. § 60.5395(c)
[44] 40 C.F.R. § 60.5365(e)
[45] 40 C.F.R. § 60.5365(e)

Item	Pennsylvania	CSSD Performance Standard	Federal	Colorado	Ohio	West Virginia
	for hazardous Air pollutants from oil and natural gas production facilities). • In accordance with 25 Pa. Code §§ 127.1 and 127.12(a)(5), the owner or operator of each storage tank with a capacity greater than 40,000 gallons shall also comply with the requirements specified in 25 Pa. Code § 129.56. These storage tanks shall be equipped with of the following vapor loss control devices: ○ An external or internal floating roof ○ A vapor recovery system • In accordance with 25 Pa. Code §§ 127.1 and 127.12(a) (5), the owner or operator of each storage tank with a capacity less than or equal to 40,000 gallons shall also comply with the requirements in 25 Pa. Code § 129.57. • These storage tanks shall be equipped with pressure relief valves.		consecutive months.[46] • Control device must be reinstalled: (1) if a well feeding the storage vessel undergoes fracturing or refracturing; or (2) the monthly emissions from the uncontrolled storage vessel increase to 4 tpy or greater.[47]	• Storage Tank Emission Management (STEM) plan and inspections for tanks with non-stabilized liquids as follows: Uncontrolled VOC Emissions (tpy) — AIMM (Approved Instrument Monitoring Method) Inspection Frequency >6 and <12 — Annually >12 and <50 — Quarterly > 50 — Monthly		
Reciprocating Compressors	GP-5/ NSPS Subpart OOOO • "New reciprocating compressors (those installed after August 23, 2011) – change rod packing either every 26,000 hours of operation or every 36 months as well as new reciprocating compressors. [50] • Reciprocating compressors located at a well site or an adjacent well site and	Performance Standard No. 14.1 • Change rod packing at all reciprocating compressors (both existing and new), including those at the wellhead, either every 26,000 hours of operation or after 36 months.	NSPS Subpart OOOO • "New" reciprocating compressors (those installed after August 23, 2011) – change rod packing either every 26,000 hours of operation or every 36 months as well as new reciprocating compressors.[52] • Reciprocating compressors located at a well site or an adjacent well site	Regulation 6: • Federal Register regulations adopted by reference: Subpart OOOO, Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution (40 CFR Part 60, Subpart OOOOO, 01-Jul-2012 as amended by 78 Fed. Reg. 58416 on 23-Sep-2013). • NSPS OOOO applies to NG wells, storage	• No state-specific requirements.	• No state-specific requirements.

[48] Ohio GP-12, at p. 41
[49] WVDEP General Permit G70-A, Section 12.1
[46] 40 C.F.R. § 60.5395(d)(2)
[47] 40 C.F.R. § 60.5395(d)(2)
[50] 40 C.F.R. §60.5385(a)

Item	Pennsylvania	CSSD Performance Standard	Federal	Colorado	Ohio	West Virginia
	servicing more than one well site are excluded from this requirement. [51]		and servicing more than one well site are excluded from this requirement.[53]	vessels, centrifugal compressors with wet seals, reciprocating compressors, pneumatic controllers, leaks and leaking components at gas plants, sweetening units, and NG well green completion provisions. • Affects all facilities regardless of emissions levels.		
Pneumatic Controllers	GP-5/ NSPS Subpart OOOO • "New" pneumatic controllers (those constructed (installed), modified or reconstructed on or after October 15, 2013) located between the wellhead and a natural gas processing plant: bleed rate of 6.0 scfh or less.[54] • Exception to 6.0 scfh bleed rate – where use of a greater bleed rate is required based on functional needs, including response time, safety and positive actuation. [55] • The owner or operator of pneumatic controllers shall also comply with the applicable requirements specified in 40 CFR Part 60, Subpart OOOO.	Performance Standard No. 14.2 • By October 15, 2013, pneumatic controllers (both existing and new): o Low – bleed, with a natural gas bleed rate limit of 6.0 scfh or less. o Zero bleed when electricity (3-phase electrical power) is on-site.	NSPS Subpart OOOO • "New" pneumatic controllers (those constructed (installed), modified or reconstructed on or after October 15, 2013) located between the wellhead and a natural gas processing plant: bleed rate of 6.0 scfh or less.56 • Exception to 6.0 scfh bleed rate – where use of a greater bleed rate is required based on functional needs, including response time, safety and positive actuation.[57]	Regulation No. 7: • Controllers placed in service on or after 01-May-2014 must o Emit in an amount less than or equal to a low-bleed controller. o Utilize no-bleed controller where on-site electrical grid power is accessible. • High-bleed controllers in service prior to 01-May-2014 must be replaced or retrofitted such that emissions are less than or equal to a low-bleed controller. • All high-bleed controllers that must remain in service must obtain State approval. • Beginning 01-May-2015 o High-bleed controllers must be tagged, and o Must be inspected monthly with attendant maintenance to minimize emissions	• No state-specific requirements. • Proposed revisions to Ohio's Oil and Gas Well-Site Production Operations, General Permit 12 require compliance with Subpart OOOO requirements for pneumatic controllers.	Natural Gas Production Facility Class II General Permit G70-A • Requires compliance with NSPS Subpart OOOO requirements for pneumatic controllers.[58]

[52] 40 C.F.R. § 60.5385(a)
[51] 40 C.F.R. §60.5365(c)
[53] 40 C.F.R. § 60.5365(c)
[54] 40 C.F.R. §60.5390(c)(1)
[55] 40 C.F.R. § 60.5390(a)
[56] 40 C.F.R. § 60.5390(c)(1)
[57] 40 C.F.R. § 60.5390(a)
[58] WVDEP General Permit G70-A, Section 8

Item	Pennsylvania	CSSD Performance Standard	Federal	Colorado	Ohio	West Virginia

Centrifugal Compressors	GP-5 -Natural Gas Compression and/or Processing Facilities
	• Compliance with NSPS Subpart OOOO requirements for centrifugal compressors.[59]
	  o Reduce VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater.
	• If a control device is used to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of §60.5411(b), that is connected through a closed vent system that meets the requirements of §60.5411(a) and routed to a control device that meets the conditions specified in §60.5412(a), (b) and (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.
		Performance Standard No. 14.3
		• New centrifugal compressors may not contain wet oil seals.
		• Replace worn out wet seals on existing centrifugal compressors with dry seals.
			NSPS Subpart OOOO
			• For centrifugal compressors installed after August 23, 2011 - must reduce VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95 % or greater.[60]
			  o If a control device is used to reduce emissions, must equip the wet seal fluid degassing system with a cover that meets the requirements of 40 CFR §60.5411(b), that is connected through a closed vent system that meets the requirements of 40 CFR §60.5411(a) and routed to a control device that meets the conditions specified in 40 CFR §60.5412(a), (b) and (c). As an alternative to routing the closed vent system to a control device, may route the closed vent system to a process.
			• Not applicable to centrifugal compressors located at a well site or at an adjacent well site and servicing more than one well site.[61]
				Regulation 6:
				• NSPS OOOO applies to NG wells, storage vessels, centrifugal compressors with wet seals, reciprocating compressors, pneumatic controllers, leaks and leaking components at gas plants, sweetening units, and NG well green completion provisions.
					• No state-specific requirements.	• No state-specific requirements.

LDAR	Exemption Category No. 38[62]
	• Perform a leak detection and repair (LDAR) program within 60 days after the well is put into production and annually thereafter.
	  o Use of optical gas imaging
		Performance Standard No. 14.4
		• By March 20, 2014 – implement a directed inspection and maintenance program (DI&M) for equipment leaks from all existing and new valves, pump seals, flanges, compressor seals,
			NSPS Subpart OOOO
			• Cover and closed vent inspections for "new" storage vessels with potential to emit VOC emissions equal to or greater than 6 tpy.[63]
			  o Monthly olfactory, visual and
				Well Production Facilities:
				• AIMM (Approved Instrument Monitoring Method) inspection must be initiated 15 to 30 days after unit commences operation for units constructed on or after 15-Oct-2014
					Oil and Gas Well-Site Production Operations, General Permit 12.1 & 12.2
					• Leaks shall be detected by the use of either a "Forward Looking Infra Red" (FLIR) camera or an analyzer meeting U.S. EPA Method 2164.
						G70-A
						• Compliance with NSPS Subpart OOOO inspection requirements for storage vessels.[65]

[59] Pennsylvania's GP-5 -Natural Gas Compression and/or Processing Facilities, Section D
[60] 40 C.F.R. § 60.5380(a)
[61] 40 C.F.R. § 60.5365(b)
[62] Pennsylvania's Air Quality Permit Exemptions
[63] 40 C.F.R. § 60.5416(c)
[64] Ohio GP-12.1 & 12.2

<table>
<tr><th>Item</th><th>Pennsylvania</th><th>CSSD Performance Standard</th><th>Federal</th><th>Colorado</th><th>Ohio</th><th>West Virginia</th></tr>
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<td></td>
<td>camera (such as FLIR) or gas leak detector.

o Conduct on valves, flanges, connectors, storage vessels/storage tanks, and compressor seals.

o If leak is discovered – repair within in 15 days unless facility shutdown is required or ordering replacement parts are necessary for the repair.

• Upon written request documenting justification – DEP may grant extension for leak detection deadlines or repairs.

• A leak is considered repaired if one of the following can be demonstrated:

o No detectable emissions consistent with EPA Method 21 specified in 40 CFR Part 60, Appendix A

o A concentration of 2.5% methane or less using a gas leak detector and a VOC concentration of 500 ppm or less

o No visible leak image when using an optical gas imaging camera

o No bubbling at leak interface using a soap solution bubble test specified in EPA Method 21

o Any other method approved in writing by the Department</td>
<td>pressure relief valves, open-ended lines, tanks and other process and operation components that result in fugitive emissions.

o Monitored by a weekly visual, auditory, and olfactory check.

o Yearly mechanical or instrument check to detect leaks.

o Repair detected significant leaks in a timely manner.

o No leak repair quantification

o No FLIR or gas detector</td>
<td>auditory inspections for defects that could result in air emissions.

o If leak detected:

▪ Within 5 days – make first repair attempt.

▪ Complete repair within 30 days.

▪ Apply grease to deteriorating or cracked gaskets to improve the seal while awaiting repair.

Delay permissible if repair requires shutdown or if emissions during repair would be greater than delay of repair until shutdown.</td>
<td>• AIMM inspection must be initiated by the phase-in schedule for units constructed before 15-Oct-2014

• AIMM inspections will continue as follows based on uncontrolled VOC emissions from the highest emitting storage tank or controlled VOC emissions from all permanent equipment:

<u>Well Production Facilities without Storage Tanks:</u>
<table>
<tr><td>Well Production Facilities WITHOUT Storage Tanks (tpy)</td><td>AIMM Inspection Frequency</td><td>AVO Inspection Frequency</td></tr>
<tr><td>0 < x < 6</td><td>One time</td><td>Monthly</td></tr>
<tr><td>6 < x < 12</td><td>Annually</td><td>Monthly</td></tr>
<tr><td>12 < x < 20</td><td>Quarterly</td><td>Monthly</td></tr>
<tr><td>x > 20</td><td>Monthly</td><td>Monthly</td></tr>
</table>
<u>Well Production Facilities with Storage Tanks:</u>
<table>
<tr><td>Well Production Facilities WITH Storage Tanks (tpy)</td><td>AIMM Inspection Frequency</td><td>AVO Inspection Frequency</td></tr>
<tr><td>0 < x < 6</td><td>One time</td><td>Monthly</td></tr>
<tr><td>6 < x < 12</td><td>Annually</td><td>Monthly</td></tr>
<tr><td>12 < x < 50</td><td>Quarterly</td><td>Monthly</td></tr>
<tr><td>x > 50</td><td>Monthly</td><td>Monthly</td></tr>
</table>
<u>Natural Gas Compressor Stations:</u>

• AIMM inspections schedule for units constructed on or after 01-Jan-2015
o With fugitive VOC emissions < 50 tons, must begin < 90 days
o With fugitive VOC emissions ></td>
<td>• 2Initial monitoring within 90 days of startup and quarterly thereafter for a period of four consecutive quarters (1 year).

• If following the initial four consecutive quarters, less than or equal to 2.0% of the ancillary equipment are determined to be leaking during the most recent quarterly monitoring event, then the frequency of monitoring can be reduced to semi-annual.

• If following two consecutive semi-annual periods, less than 2.0% of the ancillary equipment are determined to be leaking during the most recent semi-annual monitoring event, then the frequency of the monitoring can be reduced to annual.

• If more than or equal to 2.0% of the ancillary equipment are determined to be leaking during any one of the semi-annual or annual monitoring events, then the frequency of monitoring shall be returned to quarterly.

• The program shall require the first attempt at repair within five (5) calendar days of determining a leak.

• The program shall require that the leaking component is repaired within 30 calendar days after the leak is detected.

• Leaks shall be measured by utilizing U.S. EPA Method 21 (40 CFR Part 60, Appendix A). All potential leak interfaces shall be traversed as close to the interface</td>
<td></td>
</tr>
</table>

[65] WVDEP General Permit G70-A, Section 12

Item	Pennsylvania	CSSD Performance Standard	Federal	Colorado	Ohio	West Virginia

	<u>GP-5 LDAR Program</u>
	
	• At a minimum, on a monthly basis perform a leak detection and repair program that includes audible, visual, and olfactory ("AVO") inspections.
	
	• Within 180 days after initial startup and at a minimum on a quarterly basis, use forward looking infrared ("FLIR") cameras or other leak detection monitoring devices approved by the Department for the detection of fugitive leaks. The Department may grant an extension for the use of FLIR camera upon receiving a written request that documents the justification.
	
	• Repair detected leaks as soon as possible but no later than 15 days after the leak is detected.
	
	• Records must be kept for a period of 5 years.
	
	• Operators are required to submit annual reports to the DEP.
				50 tons, must begin < 30 days
				
				• AIMM inspections will continue as follows:
				
				Fugitive VOC Emissions (tpy) / **Inspection Frequency**:
				>0 and < 12 – Annually
				> 12 and < 50 – Quarterly
				> 50 – Monthly
				
				<u>Repairing Leaks:</u>
				
				• Quantitative AIMM (EPA Method 21 or other Division approved method)
				  ○ Units constructed on or after 01-May-2014, a leak is anything > 500 ppm
				  ○ Units constructed before 01-May-2014, a leak is anything > 2,000 ppm
				
				• For infra-red camera or AVO, a leak is any detectable emission not associated with normal operation.
				
				• Leaks must be repaired within
				  ○ 5 days after discovery unless parts are unavailable, equipment requires shutdown, or other good cause
				  ○ 15 days if parts need to be ordered
				  ○ If shutdown required, leak must be repaired at next scheduled shutdown
				  ○ If other good cause, leak must be repaired within 15 days good
					as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm or 10,000 ppm (as applicable) for determining compliance.
					
					• A component is considered to be leaking if the instrument reading is equal to or greater than 500 ppm or 10,000 ppm depending on the component.	

Item	Pennsylvania	CSSD Performance Standard	Federal	Colorado	Ohio	West Virginia
				cause ceases ○ Equipment must be re-monitored within 15 days of repair ○ Records must be kept for a period of 2 years ○ Operators are required to submit annual reports to the State.		
Well-bore freeze-up emissions	• Facility VOC emissions exceeding 2.7 tpy may require Plan Approval (case-by-case BAT).	Performance Standard No. 14.5 • Eliminate VOC emissions associated with the prevention of well-bore freeze-up (only de minimis emissions are permitted).	• None.		• None.	• None.
Blowdown emissions	• Facility VOC emissions exceeding 2.7 tpy may require Plan Approval (case-by-case BAT).	Performance Standard No. 14.6 • Existing and new compressors are required to be pressurized when they are off-line for operational reasons in order to reduce blowdown emissions.	• None.		• None.	• None.
Truck Emission Requirements	• States including Pennsylvania are precluded from establishing any emissions limitations other than those required by 40 CFR Part 86. • Heavy duty vehicle engines are exempt from permitting requirements under Exemption Category No. 38. • All non-road engines must comply with federal emission standards found in 40 CFR Part 86. • Only ultra-low sulfur diesel fuel will be available.	Performance Standard No. 15.1 and 15.2 • By March 20, 2014 -80% of all trucks used to transport fresh water or well flowback water must meet U.S. EPA's Final Emission Standards for 2007 and Later Model Year Highway Heavy-Duty Vehicles and Engines for particulate matter (PM) emissions. • By September 24, 2015 -95% of all trucks used to transport fresh water or well flowback water must meet U.S. EPA's Final Emission Standards for 2007 and Later Model Year Highway Heavy-Duty Vehicles and Engines for particulate matter (PM) emissions.	• U.S. EPA regulates engine emissions from highway heavy-duty vehicles based on the vehicle's model year.[66]	• States including Pennsylvania are precluded from establishing any emissions limitations other than those required by 40 CFR Part 86.	• States including Pennsylvania are precluded from establishing any emissions limitations other than those required by 40 CFR Part 86.	• States including Pennsylvania are precluded from establishing any emissions limitations other than those required by 40 CFR Part 86.

[66] 40 C.F.R. Part 86

Item	Pennsylvania	CSSD Performance Standard	Federal	Colorado	Ohio	West Virginia
Truck Load-out Emissions	Exemption Category No. 38[67] • Exemption Category No. 38 requires compliance with 95% VOC reduction requirements of other equipment such as tanker truck load-outs, consistent with § 60.5413 or alternate test methods as approved by the Department.	• None		Regulation No. 3: • The following sources are exempt because by themselves, or cumulatively as a category, they are deemed to have a negligible impact on air quality: ○ Crude oil truck loading equipment at exploration and production sites where the loading rate does not exceed 10,000 gallons of crude oil per day averaged on an annual basis. • Condensate truck loading equipment at exploration and production sites that splash fill less than 6750 barrels of condensate per year or that submerge fill less than 16308 barrels of condensate per year.		Natural Gas Production Facility Class II General Permit G70-A *Regulated Pollutant Limitation.* The registrant shall not cause, suffer, allow or permit emissions from any registered Tank Truck Loading Facility of any regulated pollutant listed in the General Permit Registration to exceed the potential to emit (pounds per hour and tons per year) recorded with the registrant's General Permit Registration without effecting a modification or administrative update. To demonstrate compliance with the tank truck loading emissions in section 11.1.1, the registrant shall not exceed the maximum throughput limit that was recorded with registrant's General Permit Registration without effecting a modification or administrative update. Compliance with the Maximum Annual Throughput Limitation shall be determined using a twelve month rolling total.

Glycol Dehydrators	GP-5
	• The owner or operator of each glycol dehydrator located at natural gas compression and/or processing facility shall comply with the applicable requirements established in 40 CFR Part 63, Subpart HH.
	• The VOC emissions from the glycol
		• None	• The owner or operator of each glycol dehydrator located at natural gas compression and/or processing facility shall comply with the applicable requirements established in 40 CFR Part 63, Subpart HH.	• For still vents and vents from any flash separator or flash tank, shall reduce hydrocarbon emissions by 95% (98% if combustion device used) except where
				  ○ Combustion device was permitted prior to 01-May-2014, and
				  ○ Dehydrator is not within 1,320 feet of a building unit or
					GP12.1 and GP 12.2
					• For Total Organic Compounds (TOC), total hazardous air pollutants (total HAP), or benzene, compliance with the applicable control requirements of 40 CFR Part 63, Subpart HH.
					• Emissions from a flare used to
						Natural Gas Production Facility Class II General Permit G70-A
						• In addition to the minimum requirements in this section, area source TEG units may also be subject to 40

[67] Pennsylvania's Air Quality Permit Exemptions

Item	Pennsylvania	CSSD Performance Standard	Federal	Colorado	Ohio	West Virginia
	dehydrator still vent stream, which has a total uncontrolled potential emission rate of VOC in excess of ten (10) tons per year, shall be controlled either by at least 85% with a condenser, a flare or other air cleaning device, or any alternative methods as approved by the Department. ○ A glycol dehydrator using a condenser as an air cleaning device shall daily achieve an average final exhaust temperature of less than 110 degrees Fahrenheit (110 ºF). ○ (c) A glycol dehydrator using a flare as an air cleaning device shall ensure destruction of VOC emissions to the flare stack by maintaining the heat content of the flare gas above 300 Btu/scf. • Visible emissions from a glycol dehydrator using a flare shall not exceed either of the following limitations: ○ Equal to or greater than 10% for a period or periods aggregating more than 3 minutes in any one hour. ○ Equal to or greater than 30% at any time. • A glycol dehydrator shall not emit malodorous air contaminants in such a manner that the malodors are detectable outside the facility property. • If a flare is used as an air cleaning device for the glycol dehydrator, the owner or operator shall maintain a record of daily visual observations of the continuous presence of a flame or a record of the continuous recorder that indicates the			designated activity area • Applies to units ○ Constructed on or after 01-May-2015 with uncontrolled VOC emissions > 2 tons per year ○ Constructed before 01-May-2015 with uncontrolled VOC emissions > 6 tons per year ○ Constructed before 01-may-2015 with uncontrolled VOC emissions > 2 tons per year if unit is within 1,320 feet of a building unit or designated activity area.	control emissions from the glycol dehydration unit shall not exceed:[68] ○ 0.25 ton Nitrogen Oxides (NOx) per month averaged over a 12-month rolling period; ○ 0.23 ton VOC per month averaged over a 12-month rolling period; and ○ 0.15 ton Sulfur dioxide (SO2) per month averaged over a 12-month rolling period. ○ Carbon Monoxide (CO) emissions from a flare used as a control device for the dehydrator shall not exceed 1.35 tons CO per month averaged over a 12-month rolling period. ○ Emissions of Volatile Organic Compounds (VOC) (excludes methane and ethane) shall not exceed 5.0 tons/year. • If a flare is used to control emissions from the dehydrator: ○ The flare shall be operated with a flame present at all times when gases are vented to it. ○ An automatic flame ignition system shall be installed. ○ If the permittee is using a pilot flame ignition	CFR 63, Subpart HH. • *Maximum Throughput Limitation*. The maximum wet natural gas throughput to the glycol dehydration units/ still columns shall not exceed the throughput limit listed in the registrant's G70-A general permit registration. Compliance with the Maximum Throughput Limitation shall be determined using a twelve month rolling total. • *Emission Limits*. The registrant shall not cause, suffer, allow or permit emissions of hazardous air pollutants (HAPs) and Volatile Organic Compounds (VOCs) to exceed the emission limits listed in the registrant's G70-A general permit registration. • *Control Devices*. The following control devices may be used: Flares Enclosed

[68] OAC (Ohio Adminstrative Code) rule 3745-31-05(A)(3), as effective 11/30/01

Item	Pennsylvania	CSSD Performance Standard	Federal	Colorado	Ohio	West Virginia
	continuous ignition of the pilot flame. • The owner or operator of a new glycol dehydrator, which is not subject to the requirements established in 40 CFR Part 63, Subpart HH and has a total uncontrolled potential emission rate of VOC in excess of five (5) tons per year shall be controlled either by at least 95% with a condenser, a flare or other air cleaning device, or any alternative methods as approved by the Department. Exemption Category No. 38 • Combined VOC emissions from all the sources at the facility less than 2.7 tons on a 12-month rolling basis. If the VOCs include HAPs, the HAP exemption criteria in this paragraph will be met. Compliance with this criterion is to be determined using any generally accepted model or calculation methodology. • If the exemption criteria cannot be met, then a case-by-case plan approval is required.				system, the presence of a pilot flame shall be monitored using a thermocouple or other equivalent device to detect the presence of a flame. A pilot flame shall be maintained at all times in the flare's pilot light burner. If the pilot flame goes out and does not relight, then an alarm shall sound. ○ If the permittee is using an electric arc ignition system, the arcing of the electric arc ignition system shall pulse continually and a device shall be installed and used to continuously monitor the electric arc ignition system. ○ Any flare, auto ignition system, and recorder shall be installed, calibrated, operated, and maintained in accordance with the manufacturer's recommendations, instructions, and operating manuals. • If a condenser (or BTEX elimination system) is used to control emissions from the dehydrator: ○ The condenser shall be operated at all times when gases are vented to it. ○ The condenser must be equipped with a continuous temperature monitoring device that continuously monitors and records the dehydration still vent	Combustion Devices Closed Vent System Carbon Adsorption Systems Condensers • The registrant shall comply with all applicable control device requirements. *Glycol Dehydration Units Recycling Back to Flame Zone of the Reboiler:* • If the registrant is reducing emissions by recycling the glycol dehydration unit back to the flame zone of the reboiler, it shall be designed and operated in accordance with the following: a. The vapors/overheads from the still column shall be routed through a condenser at all times when there is a potential that vapors (emissions) can be generated from the still column. b. The reboiler shall only be fired with vapors from the still column and flash tank, and natural gas may be used as a supplemental fuel.

Item	Pennsylvania	CSSD Performance Standard	Federal	Colorado	Ohio	West Virginia
					temperature. ○ The condenser, temperature monitoring device and recorder shall be installed, calibrated, operated, and maintained in accordance with the manufacturer's recommendations, instructions, and operating manuals. • Emission Limitation from a flare used to control the dehydrator: ○ 1.35 tons of CO per month averaged over a 12-month rolling period. ○ 0.23 ton of VOC per month averaged over a 12-month rolling period. ○ 0.25 ton of NOx per month averaged over a 12-month rolling period. ○ 0.15 ton of SO2 per month averaged over a 12-month rolling period.	c. The vapors/overheads from the still column shall be introduced into the flame zone of the reboiler as the primary fuel or with the primary fuel before the combustion chamber. To demonstrate compliance with the registrant shall monitor the throughput of wet natural gas fed to the dehydration system on a monthly basis for each glycol dehydration unit. Representative gas sample collection and analysis frequency for dehydration units shall be determined based on the level of HAP emissions from the glycol dehydration unit of the facility as set forth below: *Each dehydration unit exempt from § 63.764(d) requirements and with federally enforceable controls* - Upon request by the Director. *Each dehydration*

Item	Pennsylvania	CSSD Performance Standard	Federal	Colorado	Ohio	West Virginia
						unit exempt from § 63.764(d) requirements and without federally enforceable control - (a) An initial compliance test within 180 days of permit issuance or within 180 days of start-up of the dehydration unit, whichever is later. (b) Monitor and record bi-monthly the actual input parameters for GRI GLYCalc V3 or higher. *Every dehydration unit at or above 95% of HAPs major source levels exempt from § 63.764(d) requirements and without federally enforceable controls* - The registrant shall sample and perform a wet gas analysis at least once each year.
Natural Gas Processing Plants	• In accordance with 25 Pa. Code §§ 127.11 and 127.12(a)(5), the owner or operator of a fractionation unit located at an onshore natural gas processing plant shall comply with 40 CFR Part 60, Subpart KKK – Standards of Performance for Equipment Leaks of VOCs from Onshore Natural Gas Processing Plants.	• None	• The owner or operator of a fractionation unit located at an onshore natural gas processing plant shall comply with 40 CFR Part 60, Subpart KKK – Standards of Performance for Equipment Leaks of VOCs from Onshore Natural Gas Processing Plants.	• Not Covered by Regulations 3, 6 and 7.	• Not Covered by GP12.1 and GP12.2.	• Not covered by General Permit G-30D, G-35A, or G70-A.

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<tr><td>Turbines</td><td><u>Exemption Category No. 38:</u>
Combustion turbines rated at less than 1,000 horsepower or 10.7 gigajoules per hour.
GP-5
The owner or operator of a new or reconstructed turbine with a rated capacity equal to or greater than 1000 bhp or 10.7 gigajoules per hour (10 MMBtu/ per hour), based on the higher heating value (HHV) of the fuel that commenced construction, modification, or reconstruction after February 18, 2005, shall comply with applicable requirements specified in 40 CFR Part 60, Subpart KKKK.
In accordance with 25 Pa. Code §§ 127.1 and 127.12(a)(5), the owner or operator of a new or reconstructed turbine shall not exceed the following emissions standards:
Turbine Size ≥1,000 BHP and <5,000 BHP<table><tr><td>NOx ppmvd corrected at 15% O2</td><td>CO ppmvd corrected at 15% O2</td><td>NMNEHC (as Propane) ppmvd corrected at 15% O2</td><td>Total Particulate Matter Lbs/MMBtu</td></tr><tr><td>25</td><td>25</td><td>9</td><td>0.03</td></tr></table></td><td>None</td><td>The owner or operator of a Turbine shall comply with emissions standards specified in 40 CFR Part 60, Subpart KKKK.</td><td>Not covered by Regulations 3, 6 and 7.</td><td>Micro turbines less than 200 kW are exempt.
Not Covered by GP12.1 and GP12.2.</td><td>Not covered by General Permit G-30D, G-35A, or G70-A</td></tr>
</table>

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<tr><th>Item</th><th>Pennsylvania</th><th>CSSD Performance Standard</th><th>Federal</th><th>Colorado</th><th>Ohio</th><th>West Virginia</th></tr>
<tr><td></td><td>
Turbine Size ≥5,000 BHP and <15,000 BHP
<table>
<tr><td>NOx ppmvd corrected at 15% O2</td><td>CO ppmvd corrected at 15% O2</td><td>NMNEHC (as Propane) ppmvd corrected at 15% O2</td><td>Total Particulate Matter Lbs/MMBtu</td></tr>
<tr><td>15</td><td>25</td><td>9</td><td>0.03</td></tr>
</table>
Turbine Size ≥15,000 BHP
<table>
<tr><td>NOx ppmvd corrected at 15% O2</td><td>CO ppmvd corrected at 15% O2</td><td>NMNEHC (as Propane) ppmvd corrected at 15% O2</td><td>Total Particulate Matter Lbs/MMBtu</td></tr>
<tr><td>15</td><td>10 ppm or 93% reduction</td><td>5 ppm or 50% reduction</td><td>0.03</td></tr>
</table>
Compliance with the emissions standards in this section shall be considered compliance with the NSPS emissions standards specified in 40 CFR Part 60, Subpart KKKK and 25 Pa. Code Chapter 122 (relating to national standards of performance for new stationary sources).
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PENNSYLVANIA DEPARTMENT OF ENVIRONMENTAL PROTECTION

COMPLIANCE DEMONSTRATION INSTRUCTIONS FOR THE CATEGORY NO. 38 AIR QUALITY PERMIT EXEMPTION CRITERIA

The Category No. 38 exemption criteria apply to any well that was spudded (drilled) on or after August 10, 2013, and air contamination source that was constructed or modified on the well pad on or after August 10, 2013. The owner or operator of Exploratory wells, wildcat wells, or delineation wells as defined in 40 CFR Part 60, Subpart OOOO are not required to submit any compliance demonstration to the Department. However, the owner or operator must comply with all applicable state and federal requirements including 40 CFR Part 60, Subpart OOOO requirements.

To demonstrate compliance with the Category No. 38 exemption criteria, the owner or operator is required to use any generally accepted model or calculation methodology within 180 calendar days after the “well completion” as defined in 40 CFR Part 60, Subpart OOOO or installation of a source. Well completion means the process that allows for the flowback of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, which may vent produced hydrocarbons to the atmosphere via an open pit or tank. The 180 calendar days clock for compliance demonstration begins once flowback starts.

Within 60 calendar days after the well begins producing continuously to the flow line or to a storage vessel for collection, whichever occurs first, and annually thereafter, the owner/operator must perform a leak detection and repair (LDAR) program. No well will be considered to be put “into production” unless gas is flowing into a sales line. For any well owner or operator that is selling gas through temporary equipment designed for flowback, the well shall not be considered to be placed “into production” until the earlier of either of the following: (1) 30 days after the first gas sales through temporary flowback separator(s), if sales through such temporary equipment continue for more than 30 days; or (2) commencement of gas sales through permanent production separators. When wells are temporarily shut-in, an owner or operator is not required to perform a leak detection and repair (LDAR) program until within 60 calendar days after the well is put into production and gas is flowing into a sales line. However, the owner or operator is required to repair a leak from temporarily shut-in wells as expeditiously as practicable, but no later than 15 calendar days after it is detected at a temporarily shut-in well.

Leaks are to be repaired no later than 15 calendar days after leak detections unless facility shutdowns or ordering of replacement parts are necessary for repair of the leaks.

The initial compliance demonstration submitted to the Pennsylvania Department of Environmental Protection (the Department or DEP) may be submitted through electronic or regular mail to the appropriate DEP Regional Air Program Manager. The owner or operator is required to maintain records of the compliance demonstration for at least 5 years and the records shall be made available to the Department upon request.

These compliance demonstration instructions should assist the owners or operators of sources located at well pads to consistently comply with the criteria specified in Category No. 38 of the Air Quality Permit Exemption List (Document No. 275-2101-003). The following instructions include the necessary requirements to demonstrate compliance with each provision of the Category No. 38 exemption criteria.

The provisions of Category No. 38 are printed in “bold” text with the explanatory instructions in regular font type.

38. Oil and gas exploration, development, and production facilities and associated equipment and operations meeting the following provisions:

a. Conventional wells, wellheads and all other associated equipment. A conventional well is any well that does not meet the definition of unconventional gas well in 58 PA.C.S § 3203.

The owner or operator of conventional wells, wellheads and all other associated equipment are not required to submit a compliance demonstration to the Department.

b. Well drilling, completion and work-over activities.

<u>HOW TO DEMONSTRATE COMPLIANCE WITH THIS PROVISION</u>

The completion activities are subject to 40 CFR Part 60, Subpart OOOO and the owner or operator is required to comply with the applicable requirements.

As provided in 40 CFR § 60.5420, the owner and operator must send a copy of the 24-hour advance notice prior to the commencement of each well completion as required under Pennsylvania’s Oil and Gas Law (Act 13 of 2012) to the Air Program Manager in the appropriate DEP regional office. The notification must be submitted to DEP in writing; an e-mail will suffice.

<u>Documents required to be</u> submitted to the Department to demonstrate compliance for well completion notification requirement:

The well completion notification must include the following:

(1) Contact information for the owner or operator;

(2) Name of the Well site (if any), County and Township;

(2) API well number;

(3) Latitude/Longitude coordinates for each well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983;)

(4) Planned date of the beginning of flowback;

<u>Records to be maintained during every day of the well completion activity:</u>

During every day of the well completion activity, the owner/operator is required to maintain a daily log book containing the following information for each well completion:

(1) Location including County and Township name;

(2) API well number;

(3) Duration of flowback (hours);

(4) Duration of venting (hours);

(5) Reasons for venting to atmosphere;

(6) Duration of recovery to the flow line (hours); and

(7) Duration of combustion (hours).

<u>Documents required to be submitted to the Department to demonstrate compliance with Reduced Emissions Completion (REC) requirements</u>

(1) Contact information for the owner or operator;

(2) Location including County and Township name;

(3) API well number;

(4) Duration of flowback;

(5) Duration of recovery to the flow line;

(6) Duration of combustion;

(7) Duration of venting;

(8) Specific reasons for venting,

(9) Documentation for exception from control/recovery.

OR

Photograph of well with REC that contains the following:

A. Date of photograph;

B. Longitude and latitude of the well site embedded within or stored with the photograph (or separate GIS device visible in frame); and

C. Picture of equipment for storing or re-injecting recovered liquid, equipment for routing recovered gas to gas flow line, and the completion combustion device connected to and operating at each completion operation.

c. Non-road engines as defined in 40 CFR § 89.2.

The owner or operator of a "non-road engine" as defined in 40 CFR § 89.2 is not required to submit any compliance demonstration to the Department.

However, as required by 25 *Pa. Code* § 135.3, the owner or operator is required to report emissions from all sources, including exempted sources including non-road engines, located at the facility in the annual source report, which must be submitted to DEP by March 1st each calendar year. The Department's natural gas inventory and instructions can be located at the following web site:

http://www.portal.state.pa.us/portal/server.pt/community/emission_inventory/21810.

d. Unconventional wells, wellheads, and associated equipment, provided the applicable exemption criteria specified in subparagraphs i, ii, iii, iv and v are met.

i. Within 60 days after the well is put into production, and annually thereafter, the owner/operator will perform a leak detection and repair (LDAR) program that includes either the use of an optical gas imaging camera such as a FLIR camera or a gas leak detector capable of reading methane concentrations in air of 0% to 5% with an accuracy of +/- 0.2% or other leak detection monitoring devices approved by the Department. LDAR is to be conducted on valves, flanges, connectors, storage vessels/storage tanks, and compressor seals in natural gas or hydrocarbon liquids service. Leaks are to be repaired no later than 15 days after leak detections unless facility shutdowns or ordering of replacement parts are necessary for repair of the leaks. The optical gas imaging camera or other Department-approved gas leak detection equipment must be operated in accordance with manufacturer-recommended procedures. For the storage vessel, any leak detection and repair will be performed in accordance with 40 CFR Part 60, Subpart OOOO.

A. A leak is considered repaired if one of the following can be demonstrated:

1. **No detectable emissions consistent with Method 21 specified in 40 CFR Part 60, Appendix A;**

2. **A concentration of 2.5% methane or less using a gas leak detector and a VOC concentration of 500 ppm or less;**

3. **No visible leak image when using an optical gas imaging camera;**

4. **No bubbling at leak interface using a soap solution bubble test specified in Method 21; or a procedure based on the formation of bubbles in a soap solution that is sprayed on a potential leak source may be used for those sources that do not have continuously moving parts and that do not have a surface temperature greater than the boiling point or less than the freezing point of the soap solution; or**

5. **Any other method approved by the Department.**

B. Leaks, repair methods and repair delays will be recorded and maintained for five years. If a gas leak detector is used, a leak is to be detected by placing the probe inlet at the surface of a component. The Department may grant an extension for leak detection deadlines or repairs upon the receipt of a written request from the owner or operator of the facility documenting the justification for the requested extension.

The Department interprets the phrase “well put into production” to mean when the well is producing continuously to the flow line or to a storage vessel. Therefore, within 60 calendar days after the well begins producing continuously to the flow line or to a storage vessel for collection, whichever occurs first, and annually thereafter, the owner/operator will be required to perform a leak detection and repair (LDAR) program. No well will be considered to be put “into production” unless gas is flowing into a sales line. For any well owner or operator that is selling gas through temporary equipment designed for flowback, the well shall not be considered to be placed “into production” until the earlier of either of the following: (1) 30 days after the first gas sales through temporary flowback separator(s), if sales through such temporary equipment continue for more than 30 days; or (2) commencement of gas sales through permanent production separators. When wells are temporarily shut-in, an owner or operator is not required to perform a leak detection and repair (LDAR) program until within 60 calendar days after the well is put into production and gas is flowing into a sales line. However, the owner or operator is required to repair a leak from temporarily shut-in wells as expeditiously as practicable, but no later than 15 calendar days after it is detected at a temporarily shut-in well.

Documents required to be submitted to DEP to demonstrate compliance with LDAR requirements include the following:

(1) The equipment or component, date of leak detection, detection method and measurement data or visual image;

(2) The number of repairs not completed within 15 calendar days. A list of all equipment or components currently on the "Delay of Repair" list, the date each component was placed on the list, reasons and the scheduled dates of repairs; and

(3) The number of equipment or components that could not be repaired and reason, if applicable.

<u>Records to be maintained for LDAR requirements</u>

Following the completion of the first compliance demonstration, the owner or operator may record and maintain the data for the subsequent annual LDAR requirements in an electronic form or written log. There is no need for an owner or operator to submit video footage of the imaging camera. The owner or operator needs to maintain the record for leaks, repair methods and repair delays for five years and make the records available to the Department, upon request.

ii. Storage vessels/storage tanks or other equipment equipped with VOC emission controls achieving emissions reduction of 95% or greater. Compliance will be demonstrated consistent with 40 CFR Part 60, Subpart OOOO or an alternative test method approved by the Department.

<u>HOW TO DEMONSTRATE COMPLIANCE WITH THIS PROVISION</u>

VOC emissions from storage tanks may be calculated using generally accepted methods such as direct measurement, modeling programs such as current version of EPA TANKS, ProMax, API E&P Tanks, process simulation software such as HYSIM, HYSIS, WINSIM, PROSIM, or calculation methodologies such as Vazquez-Beggs equation.

Storage vessels/tanks subject to 40 CFR Part 60, Subpart OOOO must comply with the applicable federal requirements.

Compliance with the exemption criteria for <u>storage vessels</u> may be demonstrated by:

(1) An initial performance test and a periodic performance test as specified in 40 CFR § 60.5413 d)(2) through (10) within 60 months of a previous test;

(2) If the storage tank is equipped with combustion control device, the owner or operator may submit the performance test results conducted by the device

manufacturer. The manufacturer must demonstrate that a specific model of the control device achieves the performance requirement of 95% or more VOC control by conducting a performance test as specified in 40 CFR § 60.5413 (d)(2) through (10).

(3) Maintaining daily average control device parameters above (or below) the minimum (or maximum) level established during the performance test;

(4) Preparing a site-specific monitoring plan for a continuous monitoring system; and

(5) Conducting initial and annual inspections of covers and closed vent systems for leaks or defects.

<u>Documents required to be submitted to the Department to demonstrate compliance with the 95% VOC reduction requirement for storage vessels</u>

(1) An identification number for each affected storage vessel.

(2) The location of each storage vessel with latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(3) Documentation of the VOC emission rate determination using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production.

(4) Results of the performance tests performed as specified in 40 CFR § 60.5413 (d)(2) through (10).

<u>Documents required to be submitted to the Department to demonstrate compliance with the 95% VOC reduction requirement from other equipment</u>

(1) An identification number for each piece of affected equipment.

(2) Documentation of the VOC emission rate determination using a generally accepted model or calculation methodology.

(4) Results of the performance tests performed as specified in 40 CFR § 60.5413 (d)(2) through (10).

<u>Documents required to be submitted to the Department to demonstrate compliance with the 95% VOC reduction requirement from tanker truck load-out</u>

(1) An identification number for each piece of affected equipment.

(2) Documentation of the VOC emission rate determination using a generally accepted model or calculation methodology.

(4) Results of the performance tests performed as specified in MACT-level annual leak test or NSPS-level annual test (3 inches pressure change) or alternate test methods as approved by the Department.

iii. Combined VOC emissions from all the sources at the facility less than 2.7 tons on a 12-month rolling basis. If the VOCs include HAPs, the HAP exemption criteria in this paragraph will be met. Compliance with this criterion is to be determined using any generally accepted model or calculation methodology. Combined HAP emissions [not including Polychlorinated Biphenyls (PCBs), Chromium (Cr), Mercury (Hg), Lead (Pb), Polycyclic Organic Matter (POM), Dioxins and Furans] at the facility less than 1000 lbs of a single HAP or one ton of a combination of HAPs in any consecutive 12-month period. The emission criteria do not include emissions from sources which are approved by the Department in plan approvals, or the general plan approvals/general operating permits at the facility and the emissions from sources meeting the exemption criteria in subparagraphs i, ii, and iv.

<u>Documents required to be submitted to the Department to demonstrate compliance with this criterion</u>

The owner or operator must submit to the Department detailed VOC emissions and HAP emissions calculations using generally accepted models or calculation methodologies for the estimation of emissions include, but not limited to, vendors' data, direct measurement, modeling programs such as current version of EPA TANK, ProMax, API E&P Tanks, process simulation software, source test data from identical sources or EPA emission factors.

iv. Flaring activities as outlined below:

A. Flaring used at exploration wells to determine whether oil and/or gas exists in geological formations or to appraise the physical extent, reserves and likely production rate of an oil or gas field.

B. Flaring used for repair, maintenance, emergency or safety purposes.

C. Flaring used for other operations at a wellhead or facility to comply with 40 CFR Part 60, Subpart OOOO requirements.

D. Enclosed combustion device including enclosed flare will be used for all permanent flaring operations at a wellhead or facility. These flaring

operations will be designed and operated in accordance with the requirements of 40 CFR § 60.18.

Only “flaring operations” are required to be designed and operated in accordance with the requirements of 40 CFR § 60.18. Other enclosed devices such as thermal oxidizer are not required to comply with the requirements of § 60.18.

<u>Documents required to be submitted to the Department to demonstrate compliance with this criterion</u>

The owner or operator must submit the document (manufacturer’s certification, specification sheet, etc.) to the DEP showing that all permanent flares are enclosed and are designed and operated in accordance with 40 CFR § 60.18.

v. Combined NOx emissions from the stationary internal combustion engines at wells, and wellheads less than 100 lbs./hr., 1000 lbs./day, 2.75 tons per ozone season (the period beginning May 1 of each year and ending on September 30 the same year), and 6.6 tons per year on a 12-month rolling basis. The emissions criteria do not include emissions from sources which are approved by plan approvals or general permits at the facility.

<u>Documents required to be submitted to the Department to demonstrate compliance with this criterion</u>

The owner or operator must submit to the Department detailed NOx emissions calculations from each NOx emitting source(s) using any generally accepted model or calculation methodology, including, but not limited to, vendors’ data, source test data from identical sources, or EPA emission factors.

Carrera
Gas Companies, L.L.C.

July 6, 2015

Nicole Owens
Director, Regulatory Management
Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Re: Comments on Small Business Advocacy Review Panel for the EPA rulemaking "Emissions Standards for New and Modified Sources in the Oil and Natural Gas Sector"

Dear Ms. Owens,

Carrera Gas Companies, LLC appreciates the opportunity to submit its comments on how the upcoming NSPS rulemaking will impact small businesses. It is Carrera's belief that the only categories that will affect a midstream company are for Fugitive Emissions and Pneumatic Pumps. Please advise us if you feel that our impression is in error.

Comments on Fugitive Emissions:

Small businesses need flexibility on the methods utilized to determine the presence of fugitive emissions. Carrera's experience is that cameras can cost more than $80,000 per unit. Contractors can charge $6,000 per day or more and are not always available. Carrera believes that this is cost prohibitive and does not justify the emission reductions when other proven methods are known. Method 10 or soap testing should be included as acceptable methods to determine the existence of leaks.

The frequency of the testing is also of concern. With the limited amount of manpower and resources available to a small business, it is Carrera's opinion that the frequency of testing should not be more than once per year. It is important for government agencies to understand that small businesses do not have the ability to economically maintain large amounts of records.

The significant amount of paperwork associated with an LDAR program is always a burden on businesses such as Carrera's. Considering the size of the facilities involved, and the small amount of fugitive emissions associated with them, Carrera believes that there should be a "standard exemption" from LDAR for small facilities. Carrera would suggests that 6 tons per year of fugitives before an LDAR program is required would be a good option. Additionally, due to the complexity of the paperwork associated with any LDAR program, Carrera believes, that if a facility is subject to LDAR, there should be an allowance for a small number of missed sources before any government agency can charge a fine. Carrera suggests the greater of 5 missed sources or 5% of the total sources should be allowed before a fine can be issued.

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Comments on Pneumatic Pumps:

The three main uses Carrera has experienced for pneumatic pumps are for dehydration (field and compressor stations), chemical transfer, and chemical injection.

For field and compressor dehydration applications piston type pneumatic pumps are used. Virtually all the units are located in remote facilities that have unreliable or no electricity, no instrument air system, and rarely have an existing emission control device. This is the main reason pneumatic pumps are used instead of electric powered pumps in the first place. There is simply no other economically feasible way to operate this type of equipment without using pneumatic pumps. Because the universe of locations that have solutions recommended by the EPA already installed is so small, and installing them for this specific purpose isn't cost effective, Carrera feels that adding additional regulatory burden for so little gain doesn't make any sense, and Carrera recommends that all pneumatically driven piston type pumps be dropped regardless of location. This recommendation is reasonable if for no other reason than the amount of emissions from these devices are so small there is little reason for concern.

For chemical transfer and chemical injection, diaphragm pumps are most commonly used. These are used intermittently and almost always in remote locations. The pumps are portable, and moved quite frequently. It will be virtually impossible for a small business to keep up with the hours and locations that these pumps are in service. The paperwork burden alone would have a large negative impact on a small business. In addition, none of the proposed abatement options proposed by EPA is in any instance economically feasible. Carrera sees very little to be gained by bringing these types of pumps into the regulatory regime

Sincerely,

Robert Mitchell

Robert Mitchell
Vice President
Carrera Gas Companies, LLC

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July 6, 2015

Ms. Nicole Owens
Director, Regulatory Management
U.S. Environmental Protection Agency
William Jefferson Clinton Building
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

RE: Small Entity Representative Comments on Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector

Dear Ms. Owens and the Small Business Advocacy Review Panel:

On behalf of the Independent Petroleum Association of America ("IPAA"), please accept the following comments as a Small Entity Representative ("SER") to the Small Business Advocacy Review Panel ("SBAR") related to the Emissions Standards for New and Modified Sources in the Oil and Natural Gas Sector. Independent oil and natural gas operators and producers drill 95% of new wells and produce 85% of the natural gas and 54% of the oil in this country. Many of the independent operators and producers meet the definition of "small entity" for purpose of the pending regulations and could be significantly and disproportionately impacted. IPAA appreciates the opportunity to serve as a SER and hopes that our input to date, as well as these comments, will help influence the final regulations in such a way that minimizes the impact to small entities.

A primary issue of concern to IPAA, which will probably have the biggest single impact to small entities, is which pollutant is being directly regulated: volatile organic compounds ("VOCs") or methane. IPAA strongly encourages the U.S. Environmental Protection Agency ("EPA") to make use of the existing regulatory structure set forth in Subpart OOOO and regulate VOCs from the exploration and production segment of the industry and claim the methane reduction co-benefits. The technologies that reduce VOCs are the same for methane. There is no benefit to creating an entirely new set of regulations aimed at reducing methane – there are substantial costs however, only some of which have been recognized by EPA. Most notably absent from any cost estimate produced by EPA is the cost associated with the inevitable regulation of existing oil and natural gas exploration and production sources under Section 111(d), if EPA elects to regulate methane under Section 111(b). It is not a question of "if" but "when" – so ignoring the cost to small entities is inappropriate. EPA can address this significant omission in their cost analysis by regulating VOCs through Subpart OOOO.

Regulating VOCs would most likely put EPA on a stronger legal footing as nearly all of their cost benefit calculations are based on the original data generated to support regulation of VOCs under Subpart OOOO – not methane. Based on the information provided, EPA has not provided any justification for assuming the costs associated with controlling VOCs are valid with regard to methane.

The remainder of IPAA comments focus primarily on more specific cost/benefit concerns and suggest ways to minimize costs to small entities for oil well completions and fugitive emissions. IPAA focuses on these two emission sources as the potential regulations associated with these sources will have the greatest impact on small entities.[1]

EPA's Costs and Benefits:

As a general matter, IPAA makes two observations. First, many of the "source" documents for EPA's cost estimates are the same documents EPA relied upon in 2011 and 2012 when they promulgated Subpart OOOO. Ostensibly, a primary reason EPA engaged in the White Paper "process" in 2014 was to evaluate the control options for the particular emissions sources and the costs associated with those controls. The information learned through that process does not seem to be reflected in the "Supplemental Information – Slide 20 Data and Assumptions" document provided to the SERs after the June 18, 2015 panel meeting. Second, the last column of Supplemental Information indicates the "Annualized Cost with Savings (2012$)." No information was provided on how "savings" were calculated or the basis/support for the alleged savings. To adequately evaluate EPA's "cost-benefit" analysis, we would need to understand how the benefits were calculated.

With regard to the oil well completion estimate of 800-900 Mcf/year, it is difficult for smaller entities to evaluate the accuracy of that number and they are generally not required calculate or report the emissions. That said, it is not clear from the Supplemental Information document if the emissions calculations take into account that the actual venting of gas only takes place for a fraction of the completion time. If that fact is not accounted for in EPA's estimate, the reported "benefit" in recovered product would be overstated.

With regard to controlling fugitive emissions with enhanced leak detection and repair ("LDAR"), the cost of the implementing measures and the associated benefits very greatly depending on the scope of sources covered, the frequency in which surveys must be conducted, and the reporting requirements. Since LDAR often does not require a quantification of the amount of natural gas leaked, it is difficult to comment on EPA's estimate of 30-160 Mcf/year

[1] IPAA did not specifically focus on potential controls on compressors at the well head/pad as they are not an affected facility under Subpart OOOO and therefore are not regulated. At the June 18, 2015 SBAR Panel meeting, EPA was unwilling to comment on whether the compression at the well site would continue to be exempt under Subpart OOOO or if compression at oil wells would be exempt. IPAA strongly encourages EPA to continue the exemption under Subpart OOOO and extend the exemption as to compression at oil well pads. IPAA is unaware of any cost analysis conducted by EPA that the regulation of compression at the well pad is cost effective.

for well pads. Additional averaging of the cost benefit for all well pads may be misleading as a small percentage of the overall well pads may be responsible for a disproportionate share of the emissions. Consequently, small entities may be expending large sums of money to meet the LDAR requirement without seeing any of the benefits.

One of the principal document EPA relied upon in its Supplemental Information document for the costs associated with LDAR is Colorado Air Quality Control Commission's Initial Economic Impact Analysis for Proposed Revisions to Regulation Number 7 (5 CCR 1001-9), November 15, 2013, in particular Table 20 on page 15 of the document. While the table purports to reflect annualized costs, it appears to miss important costs that add up:

- **Camera** – the table does not seem to include costs to train inspectors to use the camera (approximately $2000) or maintenance of the camera (approximately $2500-3000);
- **Vehicle** – the table does not include costs of operating or maintaining the vehicle;
- **Recordkeeping** – the table includes $7,500 annual costs but does not include the capital costs to develop a software program to manage this recordkeeping and does not include the annual costs to maintain it;
- **Repair** – the table focuses only on "leak detection" and does not include costs to make any necessary repairs, or additional time/labor, if necessary, to send a separate individual out to repair; same with Tables 22 and 23 of the document – they only include costs to inspect and not repair/re-monitor;
- **Re-monitoring** – the table also excludes the cost for time and labor to fulfill the re-monitoring requirements after a repair.

It also appears the Colorado Air Pollution Control Division failed to include costs for audio/visual/olfactory ("AVO") – labor and time to conduct AVO inspections which is required monthly in Regulation 7, even for sites than emit 0 tpy and there is no exit ramp for this requirement. Although this is a routine practice, the recordkeeping component of AVO is an added cost for the time/administrative burden of the inspectors tasked with fulfilling this requirement and this disproportionally impacts the small entities with limited environmental staff.

IPAA reiterates its position that EPA should NOT model its LDAR program after the program implemented via Colorado Regulation 7. Industry's general experience is that it has been expensive to implement, often with little return in terms of finding leaks. Problems with Regulation 7 were predicted as well. Attached is a presentation that contains an economic impact analysis of Colorado's proposed Regulation 7. The Colorado Oil and Gas Association of America and Colorado Petroleum Association are current attempting to quantify the cost of implementing Colorado's LDAR program and IPAA suggests that EPA should contact them to determine when the results of their study would be available.

Oil Well Completions:

The physical characteristics of certain oil wells make reduced emissions completions ("RECs") and/or flaring/combustion not technically feasible or economic. As a general matter, all vertical oil wells should be exempt from RECs. The very nature of these wells make it difficult or technically not feasible to operate a two or three phase gas/liquid separator because these wells generally lack sufficient wellhead pressure or a sufficient quantity of gas. These wells require an artificial lift in order to flowback the completion fluids. So, in addition to a blanket exemption for all vertical wells, any well that requires an artificial lift should also be exempt – there simply is not enough gas and sufficient pressure to operate a separator.

Related to the above proposed exemptions are "low pressure" or "low volume wells" (sometimes referred to as stripper wells) and wells anticipated to produce "heavy oil" based on the gas-to-oil ratio ("GOR"). "Low pressure wells" should be categorically exempt and could be based on a threshold sales line/gathering line of approximately 250 psi or a simple water gradient formula of 0.465 psi/foot. The emissions associated with these types of wells are so low that even if a separator can be operated for some short period of time, the value of gas does not exceed the cost associated with bringing equipment to the site. Basing an exemption on volume or GOR can be more complicated because these parameters cannot be known with absolute certainty prior to drilling. Nonetheless, experience and engineering judgment, coupled with some sort of conditional obligations if a threshold (volume or GOR) is exceeded could be developed to help reduce the cost to smaller entities. Sufficiently conservative thresholds such as 15 bbl per day or a GOR of 500 scf/bbl would provide small entities some relief without risking the release of significant emissions.

Fugitive Emissions:

First and foremost, EPA should not dictate the technology to identifying or determining leaks. EPA may establish the goal or endpoint that the LDAR program needs to accomplish but should not mandate that leaks be detected by one technology, e.g., FLIR cameras. By doing so, it would stifle innovation, drive up costs for everyone, and disproportionally harm the smaller entities. The larger companies have the buying power to obtain the equipment at lower cost or contract with consultants at a better fixed rate. Allowing a variety of technologies spurs innovation and reduces the cost to all through competition.

LDAR requirements can be disproportionately burdensome to small entities. Many small entities have a "staff" of one that is responsible for environmental, safety and health compliance. The very nature of LDAR requirements are time consuming and may require a single person to travel to diverse geographic locations. The record keeping and reporting requirements, depending on how they are structured, can exacerbate the burden. There should be three tiers of requirements. For certain sources, there should be no LDAR obligations if there isn't a significant emissions source. For example, if it is a simple well pad, with no combustion devices and a storage vessel not subject to Subpart OOOO, the site should not be subject to LDAR. Similarly, well pads with gathering lines or well head pressure less than 150 psi should not be subject to LDAR requirements. Similarly, a second tier should be established which applies to small entities above 150 psi but below a daily production level.

The frequency of the survey is critical in terms of cost for all entities, but for the reasons set forth above, in particular for the small entity. Small entities should be given sufficient time from the start of production to conduct the initial survey – no less than 180 days. Thereafter, the survey frequency should be no more than annually.

Just as important as the frequency of the surveying are the recordkeeping and reporting requirements associated with the surveying. The recordkeeping should be limited to relevant information such as the site location, type of component, date of repair and method of repair. Tagging should be limited to only those leaking components not repaired during the survey. As indicated the reporting should be limited to annual reporting and should not duplicate state level reporting requirements and every effort should be made to deem state level reporting sufficient. Whenever possible, sources should simply be required to keep the necessary documents and be able to produce them upon request. In many instances, annual reporting is unnecessary and simply adds to the regulatory burden. To the extent annual reporting is deemed necessary, it should be limited in nature and simplified, e.g., number of new sites initially monitored within reporting period; total number of sites monitored; number of leaks repaired (excluding those repaired during survey); and number of leaks not repaired and the reason for the delay.

One final threshold that EPA should consider for both RECs and LDAR is some combination of the above criteria and number of wells per pad. Often, the number of wells per pad, along with other criteria can be an indication of a small entity. Small entities often have smaller pads with few wells and consequently a higher per well cost. As discussed above, small entities do not get to take advantage of economies of scale such that the potential regulations will disproportionally affect small entities.

Again, IPAA appreciates the opportunity to serve as a SER and would be happy to answer any questions you may have.

Sincerely,

/s/ James D. Elliott

James D. Elliott

JDE

cc: Lee Fuller
Matthew Kellogg

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July 6, 2015

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Dear Ms. Owens:

Introduction

The Pennsylvania Independent Oil & Gas Association's (PIOGA) roots go back to 1918 when the Pennsylvania Oil, Gas and Minerals Association (POGAM) was created to represent conventional oil and natural gas interests. In 1978 a group of independent Pennsylvania conventional natural gas producers left POGAM to form the Pennsylvania Natural Gas Associates (PNGA) and in 1981 that organization's name changed to the Independent Oil and Gas Association of Pennsylvania (IOGA of PA). After this split POGAM generally represented conventional oil production in northwest PA and IOGA of PA represented natural gas developers in southwestern PA. Over the years IOGA of PA's membership expanded to include Pennsylvania conventional oil producers as well as other service companies and individuals interested in the development of oil and natural gas resources in Pennsylvania. On April 1, 2010, IOGA of PA reunited with POGAM and the name of our reconstituted organization changed to the Pennsylvania Independent Oil & Gas Association.

While we do not solicit or maintain information on the size of our member companies, we are a member-driven organization and work closely with our members through established committees and so we know how large, or more precisely for this matter, how small they are. The vast majority of our members, particularly those that would be subject to or affected by the potential rule requirements have fewer than 500 employees and so qualify as small businesses. Indeed, many of our conventional producer members are "mom and pop" 3rd and 4th generation companies and even our largest conventional producers have fewer than 500 employees. Accordingly, in this matter we are able to represent the unique interests of our small entity members that would be subject to or affected by the potential rule requirements.

PIOGA appreciates the opportunity to serve as a small entity representative (SER) to the Small Business Advocacy Review Panel (SBARP) upon its formal creation. Various members of PIOGA participated on the Pre-Panel Outreach Meeting with Potential SERs on May 19, 2015 and on the actual Panel Outreach Meeting on June 18, 2015. The meetings were productive and educational. PIOGA's comments following the May 19, 2015 meeting were provided to you on May 28, 2015. We understand that PIOGA's comments following the June 18, 2015 meeting are due **on July 6, 2015.** Please note that the comments provided include our new comments and our comments and concerns previously provided on May 28, 2015.

The feedback provided is focused on whether these potential regulatory actions – 1) further control of VOC though revisions to 40 C.F.R. Part 60, Subpart OOOO, and 2) an entirely new set of New Source Performance Standards (NSPS) focused on methane emissions – will adversely affect small businesses. Sufficient information to make this determination is essential to our role as SER, which we understand is to provide advice and recommendations to the SBARP concerning options the U.S. EPA may consider that minimize impacts on small businesses while still meeting statutory obligations under the Clean Air Act.

While it is helpful to know that the suite of potential mitigation options are limited to those listed in the Methane White Papers issued by U.S. EPA in April 2014, we are still left to our imaginations as to what those regulations will look like and, accordingly, whether they may adversely affect small entities. One fact is certain – creating an entirely new set of methane NSPS for the exploration and production segment of the industry is unnecessary and will disproportionally affect small entities. Keeping the next set of regulations limited to additional VOC regulations through revision to Subpart OOOO would most likely be the single best measure to limit the differential adverse impact of new regulations on small entities. By the very nature of the size of these companies, there is often, at best, one person tasked with understanding the environmental regulations (that same person is probably also tasked with safety and health compliance as well). The learning curve for Subpart OOOO was steep enough. The U.S. EPA should not burden these entities with yet another set of regulations requiring additional reporting and monitoring requirements for a different pollutant when the supplemental environmental benefits are neither shown nor apparent.

Lessons Learned (Hopefully) from Subpart OOOO

For many small entities, Subpart OOOO represented their first significant exposure to the Clean Air Act and it was generally not positive. The outcry for regulation for the “oil and natural gas industry” was a reaction to the evolution of high volume hydraulically fractured (or “stimulated”) and horizontally drilled shale plays. From a small entity perspective there was a rush to judgment as to what was cost-effective and a “one-size fits all” approach. Perhaps the classic example of this was the reduced emission completion requirement that calculated cost-effectiveness assuming an average flowback period of 7 days. The regulations completely ignored an entire class of wells, those traditionally known as “low pressure wells” with flowback periods measured in hours or two - three days. The economics underlying the reduced emission completion requirement simply don’t work for those wells. Similarly, the technical/scientific complications associated with separation from energized wells were ignored. These are the types of issues that U.S. EPA must evaluate going forward. Some useful and informative conversations on oil well completions have been had, but it is unreasonable to expect small entities to provide information on controls they have not seen.

Another major issue was the time frames for compliance. Even though U.S. EPA tried to accommodate those concerns with phased-in control requirement for storage vessels, it was still difficult for small entities to comply or even to determine if they were in compliance. There was both a shortage of consultants and of equipment to come into compliance in a timely manner. The larger players could easily tie up the limited supply of consultants and, to the extent a consultant was available, the services came at premium cost. Some entities were left to “roll the dice” and guess whether the regulations applied. They should not have been put in that position then, and should not be now with respect to either of these regulatory actions. At the Pre- SBARP meeting, potential SERs were asked to provide specific examples. We will try to provide specifics, but the short time frame has precluded us for providing that information at this time. To a certain extent the small entities may not have the time or resources to conduct such an evaluation no matter how much time is allowed. Again, we will endeavor to provide such information but, respectfully, it is the job of the U.S. EPA to ensure – in the first instance – that its regulations take into consideration the cost to all affected facilities, especially small entities.

Finally, with regard to lessons learned from Subpart OOOO, the leak detection and repair (LDAR) requirements in the original proposal were extremely onerous. To U.S. EPA's credit some of those requirements were changed and operators were given options to demonstrate compliance. With the White Papers focusing on LDAR, PIOGA members are concerned that the new requirements will take away that flexibility and will require regulated companies to obtain extremely expensive monitoring equipment or to hire yet another set of consultants to do the testing. PIOGA incorporates in their entirety the comments of another potential SER, Sarah Bartlett, and call attention particularly to her comments on LDAR. The variables listed by Ms. Bartlett have tremendous impact on costs. The problems for small entities are exacerbated because, as stated above, there is often only one person responsible for compliance and the wells/sources can be spread out over a significant geographic area. PIOGA also requests that U.S. EPA survey existing state requirements for LDAR, minimize duplication of reporting/monitoring

Comment No. 1 - Stripper Wells should be categorically exempt from the proposed regulations.

Stripper wells are defined by the average daily production from the well. The Internal Revenue Service (IRS) does not address the individual well, but instead defines stripper well property as "a property where the average daily production of domestic crude oil and domestic natural gas produced from the wells on the property during a calendar year divided by the number of such wells is 15 barrels (barrel equivalents) or less". These are combined definitions from Internal Revenue Code (IRC) 613A(c)(6)(E) and IRS Manual 4.41.1.9 Oil and Gas Handbook; Definition of Terms Pertaining to the Oil and Gas Industry.

The IRS uses barrels or barrel equivalents in order to have a universal stripper definition for oil, gas and combined oil/gas production. When stripper well gas is produced, one must know the conversion of thousand cubic feet (MCF) to BBLs. The IRS states in 613A(c)(8)(D)(iv) "each 6,000 cubic feet of domestic natural gas shall be treated as 1 barrel of domestic crude oil." In addition, almost all sources outside of the IRS state that 6 MCF is "roughly", "approximately", or "about" 1 BOE (Barrel Oil Equivalent). (A webpage for Total, the French energy company, called Oil Industry Conversions gave the conversion factor as follows: "1 barrel of oil equivalent = 5,487 cubic feet of gas. Natural gas is converted to barrels of oil equivalent using a ratio of 5,487 cubic feet of natural gas per one barrel of crude oil. This ratio is based on the actual average equivalent energy content of TOTAL's natural gas reserves." This was the only MCF to BOE conversion found that varied (only slightly) from the IRS version.) This is a case where the approximate value is reasonable.

- So with the necessary values known, one can now apply the math.
  - 15 BOED = Stripper Well (Oil, Gas & Combined)
  - 6 MCFD = 1 BOED
  - 15 BOED x 6 MCFD per 1 BOED = 90 MCFD = Stripper Gas Well

One concern expressed by the panel during the June 18, 2015 meeting was that a metric (or metrics) used to establish regulatory applicability to a well must be determined prior to drilling. The reason for this concern was related primarily to an operators' ability to gauge whether a given well will be a stripper well or larger. However, the statics in Figure 04 illustrate that a producer can accurately predict "stripper" well status with confidence. Many smaller operators tend to drill in areas where the geological/producing formations have been proven (developed in the past), and based on the history of development in the specific location and using drilling techniques that are generally associated with stripper wells, they are able to accurately predict how these wells will perform. In such instances, the vast majority will fall under "stripper" well status.

For the purpose of this document the term "stripper well" includes the categories of wells that are commonly referred to as "conventional wells", "low pressure wells", "low volume wells", and "vertical wells" among others. The intent is to clearly distinguish the physical, technical, economic, and operational characteristics of such wells from hydraulically fractured wells with horizontal components that are typical of many of the nation's larger shale formations and by all accounts, represent the regulatory target of Subpart OOOO.

Comment No. 2 - The costs to implement reduced emission completions (RECS) on stripper oil and gas wells is prohibitively expensive.

A. <u>Flowback times for conventional wells are typically hours versus days for unconventional wells.</u>

Considering the low volume and the short duration of flowback of most tight sands and stripper oil and gas wells in Pennsylvania, the air quality impact of associated flowback emissions is insignificant when compared to unconventional shale well completions. The duration of flowback where the flow is gas or oil dominant is very short (a few hours), making it nearly impossible for an operator to recoup the cost of an REC through gas sales. U.S. EPA asserted that since "wells" are flowed back for 3 to 10 days after treatment, the operator could recoup the cost of REC equipment by directing the flowback gas through a sales meter. This scenario may be true for high volume, unconventional horizontal wells, but this is not true of stripper wells. In addition, to properly remove fracturing fluid from the well bore and stimulated reservoirs after treatment, where fracturing fluids are flowed back, requires much more time, perhaps more than two times longer than a conventional well, thereby impacting cost and schedule.

B. <u>Competition with larger operators for service contractors will inflate costs and hinder development.</u>

As mentioned previously, flowback emissions cannot simply be directed to a combustion device without the use of additional equipment. The cost and availability of this equipment will significantly impact the stripper well operator from a financial and schedule perspective. Most flowback service companies are dedicated to large scale unconventional shale well operations. Competition for these services will only to unproductive costs and will greatly hinder the small conventional operators who will likely need to delay projects to accommodate the schedules of service providers.

C. <u>Requiring RECs for oil and gas stripper wells is cost prohibitive.</u>

Based on quotes from three different service companies, it is estimated that it will cost between $5,000 and $7,000 per day for an operator of stripper wells to effectively separate and flare gas, or separate and feed gas to a sales line for such stripper wells.

1. Assuming $6,000/day for REC equipment for two days, plus an estimated additional $1,000 for an extra day for a service rig equates to an additional $13,000 per well. This assumes that the completion process only takes two days, which may be underestimated. As stated earlier, to flare any well, the gas and liquids must be separated. The flowback must be restricted using a choke system in order for the separator to work properly. Since the flow is restricted by the equipment, it will take somewhat longer for any well to complete than it would without the equipment.

2. Assuming a two day flowback using a REC at a cost of $13,000 and an average open flow of **532 mcfd or 7.5 boed** for a stripper well, **the price for an mcf of gas would need to be greater than $12/mcf and the price per barrel of oil would need to be more than $800/barrel just for the operator to recoup their costs.** Obviously, this is not practical or sustainable for the operator and will quickly lead to a drastic decrease in new production. The negative impact on small business will be significant.

Comment No. 3 - Size is important – any new regulatory burdens must be crafted to ensure that small entity operators are not disproportionally impacted by Subpart OOOO or related regulatory actions.

In our representation of small entities, our position is that there needs to be a clear distinction between large gas and oil producers compared to small gas and oil producers, taking into consideration both the type of well (i.e., high yield, unconventional shale wells vs. stripper wells) and the annual volume of natural gas produced. It appears in the U.S EPA issued Methane White Papers that the bulk of the data developed and relied upon by U.S. EPA was based on modern unconventional shale plays, such as the Bakken and the Eagle Ford. It is unclear if the information includes representative data collected in the Appalachian basin from both historic stripper well fields, as well as the modern shale plays. The unconventional shale plays almost universally produce larger quantities of oil and gas from different geological formations and exhibit vastly different hydrocarbon profiles. This results in “emission standards” that are not appropriate for stripper well operations; thereby forcing smaller producers employing stripper wells to comply with overly stringent requirements that are not cost-effective to their distinct operations. It would be helpful if the Panel could provide data demonstrating that it has accurate, relevant data on stripper well operations in the Appalachian Basin. If that information has not been gathered, PIOGA suggests that the applicability of additional regulations under Subpart OOOO or new NSPS for methane be delayed until the impact of those regulations can be evaluated and U.S. EPA can demonstrate that those regulations are cost effective for the small entities. It appears that the benchmark well type and associated production facilities predominantly reflect large scale wells that are typical of modern unconventional shale plays. The Methane White Papers do not address stripper wells and their associated completion practices and production equipment. U.S. EPA must examine this subset of wells common in the Appalachian basin and determine if emissions reductions can be achieved in a cost effective manner. One size fits all regulations that affect the wide range of practices in the oil and natural gas production industry are unfair, impractical, and unnecessary

We suggest that U.S. EPA consider establishing an overall applicability threshold that could be based on a number of metrics including, but not limited to; production, emissions, well depth, formation, revenue, some combination thereof, or another measurable metric that clearly delineates a “white line” for regulatory applicability. For example, if a business does not emit sufficient GHG (or produce a certain MMcf of gas or Bbl of oil) to be required to report under 40 CFR Part 98, then that entity should be exempt from any additional requirements of 40 CFR Part 60 Subpart OOOO or new methane regulations. If U.S. EPA has reviewed or explored such standards, that information would be extremely helpful (indeed, is required) in determining the potential impact of future regulations on small entities.

Comment No. 4 – Any proposed revisions to Subpart OOOO must consider the drastic differences in well types.

U.S. EPA's Subpart OOOO—Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution (Subpart OOOO) regulations published August 16, 2012[1], overall, fail to consider the drastic differences between unconventional wells with horizontal components and stripper wells that are common in Pennsylvania and other oil and gas producing states within the Appalachian basin. As a result of U.S. EPA's reliance on data from its Natural Gas STAR program, which is not representative of conventional operations in the Appalachian Basin, the agency has:

1) Drastically overestimated emissions
2) Produced an inaccurate cost-benefit analysis
3) Failed to address different hydraulic fracturing techniques as well as the drastic difference in scale, i.e.- small volume water based and nitrogen based (stripper wells) vs. large volume water based (shale wells)

The failure to appreciate differences between shale plays and drilling techniques is a disparity that has apparently carried over into U.S. EPA's cost estimates in association with the five "White Papers" that will likely form the basis of the anticipated proposed revisions to Subpart OOOO. In that regard, U.S. EPA must consider the significant impact that the increased costs associated with RECs will have on small businesses that develop both oil and gas stripper wells.

Based on the Pennsylvania Department of Environmental Protection, there are nearly 100,000 active stripper wells and over 5,000 active unconventional shale wells in the Commonwealth. Clearly, there is a need to differentiate the regulations accordingly. The number of stripper wells in Pennsylvania alone also demonstrates the folly associated with regulating methane directly via a new NSPS versus simply modifying Subpart OOOO. Despite U.S. EPA's statements that they have no intention to regulate existing sources, if the agency elects to regulate methane directly under Section 111(b), it is only a matter of time until environmental groups sue them to regulate existing sources under Section 111(d). Such regulation is unnecessary and would cripple the operators of stripper wells.

A. RECs are cost prohibitive for smaller stripper well operators.

[1] To its credit, EPA has recognized that Reduced Emissions Completion ("REC") requirements should not be applicable to all conventional gas wells which are hydraulically fractured. In its amendments to Subpart OOOO which took effect on December 31, 2014, EPA concluded that full REC requirements should not be applicable to wells for which the operation of a separator during flowback is technically infeasible. See Preamble to Final 2014 Amendments, 79 F.R. 79021 (December 31, 2014). While PIOGA appreciates this change, PIOGA respectfully does not believe it goes far enough in addressing PIOGA's concerns. First and foremost, the change is based solely upon technical feasibility and does not take into account the different economics of conventional versus large scale unconventional shale gas wells in determining what is appropriate from a regulatory perspective. Next, it would not necessarily exempt all stripper wells – only those for which the operation of a separator during flowback is technically infeasible. In short, while as indicated, PIOGA appreciates EPA's consideration in the above regard, it nevertheless supports a categorical exemption of stripper wells from the proposed regulation.

Much of the proposed Subpart OOOO rulemaking, particularly as it applies to RECs, is biased towards modern, high profile shale gas wells with horizontal components. Unjustly, the rule does not distinguish between these unconventional wells and stripper wells with characteristics of much smaller produced volumes of oil and gas, lower reservoir pressures, and with lower emissions associated with post stimulation flowback. The additional costs associated with RECs on stripper wells will likely prevent many of these marginally economic wells from being drilled and could have devastating financial impacts on the small businesses who drill them.

B. <u>The costs associated with RECs are not recouped through the short periods associated with stripper wells.</u>

The duration of post stimulation flowback events associated with different well types (i.e., stripper vs. unconventional) must be carefully considered. Within the white papers, the U.S. EPA estimated that the flowback periods will typically be 3 to 10 days with 7 days being a reasonable average. This estimate is only reasonable when it is applied to large shale wells with horizontal components and multistage completions. However, this estimate is far from reality when describing the average flowback period associated with the much smaller stripper wells. The total duration of flowback of these wells is far less, typically less than 24 hours. Additionally, where the flow is gas dominant, the period of flowback is even shorter, perhaps only a few hours. Contrary to U.S. EPA claims, it will be impossible for a stripper well operator to recoup the costs associated with using a completion combustion device and/or REC equipment. It is also important to note that for a combustion device to work properly, the well must be equipped with much of the same equipment during completion that is required for a REC meaning significant costs are still incurred without any benefit in terms of product preserved for sale. For example:

1. Similar equipment needed to perform RECs is needed to effectively route emissions to a combustion device.
    a. Chokes – to feed consistent pressure and volumes to the separator.
    b. Sand traps – to prevent solids from entering the separator.
    c. Separator – to separate liquids from gas.
    d. Flare unit with auto ignition – to safely ignite emissions when LEL is reached.
    e. Pressure tested and certified iron to plumb the system together.
    f. Personnel

C. <u>Many stripper oil wells do not produce significant amounts of gas.</u>

The duration of flowback for stripper oil wells is generally less than 24 hours as opposed to multiple days (3 to 10+) for unconventional shale wells. In terms of flowback duration, much of the flowback associated with stripper wells is dominated by liquid flow, making combustion generally technically infeasible. Typically, once stripper oil wells stop returning fracturing fluids and transition to a gas dominant or oil dominant flow, the flowback procedure ends and the wells are shut-in, and there is no separation flowback stage. The flowback process consists of an initial flowback stage and a production stage only. The time of flowback is commonly less than 24 hours in total duration.

D. <u>The volumes of natural gas flowback emissions associated with stripper wells in Pennsylvania are drastically different from the volumes associated with unconventional shale flowback volumes.</u>

1. Stripper gas wells – The 15,649 conventional gas wells that were hydraulically fractured from 2000 to 2014 in Pennsylvania had an average open flow of 532 thousand cubic feet of gas per day (mcfd) and an average shut in pressure of 855 psi. (Figure 01).

2. Stripper oil wells – The 585 conventional oil wells hydraulically fractured from 2000 to 2014 in Pennsylvania had an average open flow of 7.5 barrels of oil per day (bopd) and an average shut in pressure of 215 psi. The gas volumes associated with the oil open flows average 74 mcfd (Figure 02).

3. Unconventional (high volume/high pressure shale wells) – The 2,161 unconventional shale wells hydraulically fractured from 2002 to 2014 had an average open flow of 5,876 mcfd and an average shut in pressure of 2,455 psi. (Figure 03).

Based on the volumes alone and ignoring completion duration, the production volume associated with unconventional shale wells are over 11 times greater than those of stripper wells. Therefore a "one size fits all" approach regarding the requirement for RECs on all hydraulically fractured oil wells (and hydraulically fractured gas wells) is unreasonable and results in a disproportionate technical, resource, and financial burden on small businesses operators. Please note that the referenced figures use the terms "conventional" and "unconventional". The conventional wells referenced in the figures are generally stripper wells as previously defined. The unconventional wells represent wells drilled in the Marcellus formation, are hydraulically fractured, and include horizontal components.

Comment No. 5 - Stripper wells that produce less than or equal to 15 BOED or gas wells that produce less than or equal to 90 MCFD should not be subject to additional regulation.

In most cases, newly drilled vertical hydrofractured oil and gas wells begin their productive lives as stripper wells and never exceed 90 MCFD or 15 BOED. Therefore, using the stripper well designation provides a reasonable threshold for when RECs should be incorporated into the completion process. Figure 04 summarizes data to support this statement. The analysis of the 1st year average daily production rate of 9,440 vertical gas wells and 406 vertical oil wells in Pennsylvania show production volumes well below the 90 MCFD or 15 BOED thresholds for stripper classification.

Comment No. 6 – The use of RECs on stripper oil and gas wells could impact the productivity of such wells.

The implementation of RECs could ultimately have an adverse effect on the productivity and longevity of pressure stripper wells which will translate into lost revenue for the operator and royalty owners. After the stripper well is hydraulically fractured, it is very important that the water used to fracture the well is allowed to efficiently flow from the well at the time of flowback. Restricting the flowback through the use of a choke system will likely result in an increased amount of trapped fluid left in the reservoir. In addition, the permeability of the reservoir can be altered due to the effects of the fracturing fluids left behind in reservoirs, hindering the flow of oil and gas. If excessive amounts of fracturing fluids are trapped in the stimulated formations, it could have an adverse effect on the well's ability to produce oil and gas efficiently.

Additional Concerns and Comments:

A. The proposed additional emission standards are a concern to small entities as they pertain to compressors, liquids unloading, and fugitive emissions. As an example, some small entity natural gas and oil producers utilize small reciprocating compressors at their wells. These compressors are typically driven by 18 or 20 bhp engines, moving small amounts of natural gas. The compressor standards discussed in the "White Papers" are concerning, because they imply that the proposed standards will be derived from larger compressors (such as a stage 3 compressor) moving significantly larger quantities of gas, compressing into significantly higher line pressures (500 to 1,000 psig). Information on the size of compressors and/or any potential exemptions below a certain bhp would be helpful in evaluating the potential impact of the regulations. Compressors at the well head are currently exempt from regulation under Subpart OOOO. The exemption should be maintained and carried forward to any future regulations.

B. The industry is in a down-turn. Small entity operators, particularly ones that own, operate, and maintain stripper wells in the Marcellus region have taken the hardest hit during this downturn. While NYMEX might indicate a natural gas price of $3 per MMBtu (or Therm), due to the glut of gas in the region the actual local prices for natural gas might be as low as 50% or less of the NYMEX price. We suggest that the cost/benefit analysis of any proposed new regulations take the actual local prices of natural gas into account in the analyses when determining the economic impact of such rules on small entity operators. If U.S. EPA has accounted for such regional/local price difference in the cost effectiveness analysis, that information would help us evaluate the potential impact of the regulations.

C. Due to costs associated with increased regulation, PIOGA conventional operators have not engaged in any new well development in several years. For example, one PIOGA member paid a consultant over $35,000 to simply determine compliance with new state and federal air regulations and compliance reporting preparation/submittal. Again – this did not include the cost of coming into compliance or the ongoing reporting and monitoring costs. On the small margins that certain small entities operate, that can be the difference between drilling and not drilling. Additional regulations will only exacerbate this problem. Small entity operators simply cannot absorb these additional economic burdens, especially during this regional business downturn. Additionally, the environmental benefit of additional regulations on small entity operators is unlikely to outweigh the economic impact on their operations. We suggest that the cost/benefit analysis of any proposed new regulations consider the actual local prices of natural gas into account in the analyses when determining the environmental benefit of such rules on the environment when imposed on small entity operators.

D. Our experience with Subpart OOOO has been that small operators have had difficulty interpreting the regulatory language regarding the various requirements and even the applicability of the rule . We suggest that any new regulations that will impact small entity operators be written in a clear manner, without ambiguity, that is easily understood and interpreted by the entire oil and gas industry. We also suggest that this be accomplished by U.S. EPA working with small entity operators in a collaborative manner to obtain meaningful input and ensure that any new regulatory proposals do not cause disproportionate regulatory, financial, or compliance impact.

E. The State of Pennsylvania has an Air Quality Program in place that includes an exemption from permitting. "Exemption 38a." states that a conventional well (stripper well – low pressure and volume) and its associated equipment is exempt from more rigorous air quality permitting requirements in accordance with the State Implementation Plan (SIP). To avoid overlap and ambiguity, the U.S. EPA needs to review and consider the requirements of each SIP to determine if additional and redundant air quality regulations at the federal level are truly required for small business operators.

Sincerely,

Kevin J Moody

Kevin J. Moody
General Counsel
PIOGA

cc: Lou D'Amico
Shane Kriebel
David Ochs
Roy Rakiewicz
Matt Kellogg
James Elliott

Figure 01

Conventional "Gas" and "Gas & Oil" Wells Initial Potentials			
Year Completed	# of Wells	Average of After Treatment Gas Volume (Mcf)	Average of After Treatment Rock Pressure (#'s)
2000	920	646	898
2001	1,258	631	883
2002	1,145	579	931
2003	1,323	586	906
2004	1,547	490	877
2005	1,959	501	810
2006	2,201	526	861
2007	2,134	427	829
2008	1,821	477	851
2009	825	455	774
2010	405	691	742
2011	70	348	778
2012	22	6,103	709
2013	6	133	207
2014	13	54	113
Grand Total	15,649	532	855

Figure 02

Conventional "Oil" Wells Initial Potentials				
Year Completed	# of Wells	Average of After Treatment Oil Volume (Bbl)	Average of After Treatment Gas Volume (Mcf)	Average of After Treatment Rock Pressure (#'s)
2000	55	6.2	55	443
2001	83	5.0	64	424
2002	26	10.0	18	211
2003	49	10.0	29	234
2004	47	10.0	60	309
2005	38	10.0	14	209
2006	44	8.3	107	180
2007	74	9.2	145	180
2008	53	2.0	209	174
2009	15	N/A	7	120
2010	24	N/A	9	84
2011	6	N/A	7	80
2012	19	N/A	8	63
2013	39	46.0	57	106
2014	13	N/A	50	111
Grand Total	585	7.5	74	215

Figure 03

Unconventional Wells Initial Potentials									
Year Completed	Horizontal Well			Vertical Well			Total # of Wells	Total Average of After Treatment Gas Volume (Mcf)	Total Average of After Treatment Rock Pressure (#'s)
	# of Wells	Average of After Treatment Gas Volume (Mcf)	Average of After Treatment Rock Pressure (#'s)	# of Wells	Average of After Treatment Gas Volume (Mcf)	Average of After Treatment Rock Pressure (#'s)			
2002				1	150	2,350	1	150	2,350
2003				2	115	1,200	2	115	1,200
2004				2	965	3,300	2	965	3,300
2005				1	150	2,625	1	150	2,625
2006	1	200	2,460	2	200	2,825	3	200	2,703
2007	2	475	210	29	478	1,562	31	478	1,449
2008	8	1,740	2,377	70	730	2,006	78	834	2,041
2009	94	5,884	4,903	71	1,517	2,002	165	4,005	3,504
2010	294	6,937	2,723	28	2,173	2,185	322	6,523	2,677
2011	415	5,962	2,170	5	4,764	2,107	420	5,948	2,169
2012	525	6,304	2,359	7	4,056	2,135	532	6,275	2,356
2013	368	5,981	2,399	4	7,267	2,894	372	5,995	2,405
2014	230	7,769	2,482	2	571	3,481	232	7,707	2,491
Grand Total	**1,937**	**6,391**	**2,507**	**224**	**1,423**	**2,029**	**2,161**	**5,876**	**2,455**

Figure 04

1st Year Production Averages for Conventional "Gas" and "Gas & Oil" Wells							
Year Completed	# of Wells	Average Gas Quantity (Mcf)	Average # Gas Production Days	Average Mcf/day	Average Oil Quantity (Bbl)	Average # Oil Production Days	Average Bbl/day
2000	553	10,936	306	36.8	614	356	1.71
2001	681	10,646	309	36.3	239	267	2.64
2002	553	11,200	314	37.0	94	299	0.42
2003	864	9,485	325	30.5	604	299	1.86
2004	923	9,784	321	31.4	1,263	324	3.50
2005	1,103	16,609	310	55.6	279	252	1.18
2006	1,274	9,339	313	30.7	142	130	1.09
2007	1,454	7,545	330	23.9	189	324	0.59
2008	1,147	7,026	330	22.3	115	274	0.42
2009	606	7,667	325	24.1	99	122	0.68
2010	225	8,002	309	25.9	119	334	0.44
2011	46	13,014	290	44.1	268	302	0.93
2012	11	6,089	280	22.1			
2013							
Grand Total	9,440	9,858	319	32.2	278	239	1.30

Figure 04
(continued)

1st Year Production Averages for Conventional "Oil" Wells							
Year Completed	# of Wells	Average Gas Quantity (Mcf)	Average # Gas Production Days	Average Mcf/day	Average Oil Quantity (Bbl)	Average # Oil Production Days	Average Bbl/day
2000	52	4,127	364	11.3	656	350	1.92
2001	73	3,097	365	8.5	262	362	0.74
2002	17	1,893	334	5.8	531	334	1.64
2003	32	2,458	355	6.8	555	336	1.63
2004	40	2,535	362	7.0	446	354	1.30
2005	34	3,700	305	13.2	576	286	2.28
2006	37	3,569	336	12.3	378	326	1.20
2007	32	1,477	338	4.5	339	299	1.16
2008	32	567	331	1.8	233	265	1.16
2009	6	119	350	0.3	40	300	0.13
2010	24	912	350	2.6	308	311	0.99
2011							
2012	9	230	214	1.1	178	348	0.51
2013	1	230	214	1.1	98	214	0.46
Grand Total	406	2,631	347	7.9	408	328	1.31

Data Acquired Through DEP:

Pennsylvania Internet Record Imaging System (PA*IRIS) Website:

http://www.pairis.state.pa.us/Citrix/MetaFrame/auth/login.aspx

WIS Reports:

Well Report by County
Well Initial Potential

Oil & Gas Reports

http://www.depreportingservices.state.pa.us/ReportServer/Pages/ReportViewer.aspx?/Oil_Gas/Spud_External_Data

Spud data for 1-1-2000 through 6-23-2015
*Utilized columns: Unconventional, Configuration, Well Status, Well Type, and Spud Date

Production

https://www.paoilandgasreporting.state.pa.us/publicreports/Modules/DataExports/DataExports.aspx
*Statewide data downloads for years 2000-2014

UNCONVENTIONAL WELL INFO:

Counties Included:

Allegheny	Jefferson
Armstrong	Lawrence
Beaver	Lycoming
Bedford	McKean
Bradford	Mercer
Butler	Potter
Cambria	Somerset
Cameron	Susquehanna
Centre	Tioga
Clarion	Venango
Clearfield	Warren
Clinton	Washington
Crawford	Westmoreland
Elk	Wyoming
Erie	Fayette
Forest	Greene
Indiana	

Well Type (from WIS reports) EXCLUDED:

Observation
Junked

Well Type (from Spud Data reports) EXCLUDED:

Observation

Plug Flag Status EXCLUDED:

F

Unconventional EXCLUDED:

No

The following wells had Spud Dates used in place of Completion Dates:

033-26638, 059-25035, 059-25035, 059-25280, 059-25280, 125-23901, 081-20251, 125-23981, 051-24428, 059-25609, 059-25609, 115-20574, 125-24460, 081-21011, 033-26843, 015-20706, 015-20995, 015-20997, 125-24314, 125-24406, 117-20977, 117-20981, 027-21692, 033-27071, 033-27073, 007-20334, 007-20335, 117-20982, 035-21281, 015-22144, 085-24637, 123-47020, 015-22359, 115-21437, 015-22795

Permit Number:
Remove duplicates

Unconventional IP WELL INFO:

- Exclude wells w/o IP data
- NOTE: Likely errors were found within the "After Treatment Gas Volume" due to unit conversion errors. These errors reported IP's that were likely 1,000 times less than what they actually were. These errors were left in the data to avoid judgement on what IP's were erroneous and which were correct.

CONVENTIONAL WELL INFO:

Counties Included:

Allegheny	Jefferson
Armstrong	Lawrence
Beaver	Lycoming
Bedford	McKean
Bradford	Mercer
Butler	Potter
Cambria	Somerset
Cameron	Susquehanna
Centre	Tioga
Clarion	Venango

Clearfield
Clinton
Crawford
Elk
Erie
Forest
Indiana
Warren
Washington
Westmoreland
Wyoming
Fayette
Greene

Well Type (from WIS reports) EXCLUDED:

Water Intake
Test Well
Storage
Observation
Junked
Injection
Disposal
Core
Coal Vent
Coalbed Methane

Well Type (from Spud Data reports) EXCLUDED:

Waste Disposal
Storage
Observation
Injection
Coalbed Methane

Plug Flag Status EXCLUDED:

F
P

Configuration EXCLUDED:

Deviated
Horizontal

Unconventional EXCLUDED:

Yes

Reg Status EXCLUDED:

OR (orphan)

Formation Name EXCLUDED:

Marcellus
Rhinestreet Shale

Permit Number:

Remove duplicates

Conventional IP WELL INFO:

- Exclude wells w/o IP data
- Exclude wells with Completion Date prior to the year 2000 (using completion date from WIS Well Report by County)
- Exclude wells with Completion Dates prior to the year 2000 (using drilling completion date from WIS Well Initial Potential Report)
- Exclude Completion Event status "Deviated", "Drilled Deeper", "Old Well", and "Reworked"
- NOTE: Likely errors were found within the "After Treatment Gas Volume" due to unit conversion errors. These errors reported IP's that were likely 1,000 times more than what they actually were. These errors were left in the data to avoid judgement on what IP's were erroneous and which were correct.

CONVENTIONAL WELL 1st Year Production:

1. Started with wells that had IP data and completed in the year 2000 or later
2. Eliminate years of no production
3. Only take 1st year of production reported for each well. Production year either matches the year the well was completed or the year after.
4. Exclude wells with <182 days production for either gas or oil or >372 days

Exclude the following 17 wells due to extreme likelihood of error: 083-51435, 083-51436, 083-51437, 083-51438, 083-51439, 083-51440, 083-51441, 083-51442, 083-51443, 083-51444, 083-51445, 083-5144

Prism Midstream LLC

July 6, 2015

Nicole Owens
Director, Regulatory Management
Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Re: Comments on Small Business Advocacy Review Panel for the EPA rulemaking "Emissions Standards for New and Modified Sources in the Oil and Natural Gas Sector"

Dear Ms. Owens,

Thank you for the opportunity to provide input to the Panel regarding the upcoming NSPS rulemaking and how it will impact small businesses such as ours. I believe the only categories that were discussed that would affect our midstream company are Fugitive Emissions and Pneumatic Pumps.

Fugitive Emissions

It is important to provide optionality if leak surveys are required for fugitive emissions. Options should include Method 21 and Soap Test as well as the IR Camera. Providing no alternative to the IR Camera puts the small business at a disadvantage when the demand on a limited supply is high. We lack the buying power and the resources required when there is a shortage of equipment and/or contractors. If IR Cameras are required there should be an extension of the deadline, or a rolling grace period to allow small businesses to acquire the necessary contract services.

Frequency should be no more than once a year with an exemption or a different monitoring frequency for remote locations and low emitting sources, much like the tank exemptions in previous NSPS OOOO rulemaking.

Also to consider when requiring a LDAR program are the associated administrative duties. Small businesses have limited personnel that often times have multiple responsibilities. To properly administer an LDAR program would include training, identifying affected components, determining monitoring frequency and methodology, repair strategy and timeline and recordkeeping and reporting. Small businesses do not have elaborate data management systems that track information and compile reports. Therefore, it is important to keep the recordkeeping and reporting associated with the program as straightforward and brief as possible. It is likely that additional staff or contractors would be required to comply with an LDAR program for fugitive emissions.

Pneumatic Pumps

Gas processing plants have a very small number of pneumatic pumps. It appears that there is little benefit trying to control pneumatic pump emissions from gas processing plants. Gas driven, pneumatic diaphragm pumps are sometimes used on an intermittent basis to pump out sump pumps at remote locations. These are used only a small percentage of the time (i.e. <500 hours/year). Pneumatic pumps are also used for chemical injection. These pumps are very low volume. EPA should consider an exemption for pneumatic pumps used periodically or are low volume pumps.

The decision to use pneumatic pumps is typically driven by the fact it is located in a remote location with no existing infrastructure. An exemption for remote location would seem appropriate.

Combustion controls should only be required if a control is required for another source. Emissions from pneumatic pumps alone cannot justify the installation of a flare

Lastly, why has EPA sent the rule to OMB OIRA before the comments from the SERs are received? Doesn't this reduce the impact that the SBREFA process is supposed to have in getting small business impact into the rulemaking process? Does this comply with the EPA guidance developed to conduct this process?

Sincerely,

Julie Lang

Julie Lang
Director of Regulatory Affairs
Prism Midstream LLC

TXOGA

TEXAS OIL & GAS ASSOCIATION | SINCE 1919

Jonny Jones
Chairman

D. Todd Staples
President

July 2, 2015

Nicole Owens
Director, Regulatory Management
EPA Headquarters
1200 Pennsylvania Ave NW
Washington DC 20004

RE: Comments on Draft Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector

Dear Nicole,

The Texas Oil and Gas Association (TXOGA) appreciates the opportunity to represent small entity operators (SEO) as an SER in the SBAR Panel process. TXOGA membership includes small companies that may only operate a few wells. From what was presented by EPA at the SER meeting and conference call on June 18, 2015, we do have a few comments with respect to the upcoming NSPS, Subpart OOOO rule amendment to add additional regulated sources that is expected to be proposed by late summer.

General Comments

1. Our first comment regards the role SERs truly play in the panel process itself. In its May 19th pre-panel presentation to the SERs EPA clearly stated that:

   > "It is EPA's policy to host Panels well before a proposed rule is written so we have adequate time to incorporate SER advice and recommendations into senior management decision-making about the proposed rule."

   However, just 3 business days after the SER convened to discuss the rule proposal, EPA submitted a proposed rule on June 23rd to OMB for its required review. Clearly, a proposed rule had to be drafted well before the SER meeting was convened in order to be submitted so quickly afterwards to OMB. As a result of this apparent violation of EPA's own policy, TXOGA questions the role the SERs truly play in advising the SBAR panel and EPA with respect to actual rule development. Since EPA has now given the appearance that the SBAR panel process is merely a formality rather than an important step in development of the rule, TXOGA requests that EPA explain by letter to the SERs if and how they will address SER comments being provided to them in this process.

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2. This rule is only one of four rulemakings (NSPS OOOO, Tribal Minor Source NSR Permit Streamlining, Source Determination, and BLM Venting and Flaring) and two program actions that are being proposed concurrently (Control Techniques Guidelines and Enhanced Natural Gas Star) as part of the White House's announced Climate Action Plan (CAP) also covering the oil and gas upstream operations. It will be challenging enough for large operators, but small entity operators (SEO) with limited environmental staff need more time for reviewing and providing comments on a suite of complex regulations being proposed simultaneously. A 60-day comment period is insufficient. The comment period should be at least 90 days, but to truly provide small entities with the time necessary to analyse impacts while also continuing to work on existing compliance obligations 120 days would be far more reasonable and more likely to provide the agency with the input it is seeking to obtain.

Regulation of Methane/Covered Sources

1. EPA must make a source category specific endangerment finding. EPA is authorized to establish emissions limitations for a source category under § 111 if, in the Administrator's judgment, "it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." CAA § 111(b)(1)(A). This provision is relevant for two reasons. First, it plainly requires EPA to make a source category-specific endangerment finding prior to regulating a given source category under § 111. The endangerment finding also must be pollutant-specific – i.e., a separate endangerment finding must be made for each pollutant that EPA regulates from a given source category under § 111.

2. The scope of the current source category does not include natural gas transmission and storage sources. In 1979, the EPA listed "crude oil and natural gas production" on its priority list of source categories for promulgation of NSPS (44 FR 49222, August 21, 1979). In both the initial listing and the subsequent standards, EPA only analyzed contribution to endangerment of human health and the environment from production and gas processing facilities. Nowhere in the initial source category listing or in the subsequent standards did EPA make a determination on natural gas transmission and, as such, it should be a separate source category. Transmission has a fundamentally different profile of potential emissions and controls than oil and gas production and natural gas processing. Before proceeding with any proposed standard, EPA should make a source category determination under 111(a)(b)(1)(A). If EPA fails to do so in the proposed rule, a request for comment on this issue should be provided.

Pneumatic Pumps/Controllers

1. Gas driven, pneumatic diaphragm pumps are sometimes used on an intermittent basis to pump out sump pumps at remote locations. These are used only a small percentage of the time (typically < 500 hours/year). Even if EPA proposes requirements, the agency should at least request comment on an exemption for pneumatic pumps used only periodically.

2. From the SER presentation, EPA doesn't appear to be differentiating between chemical injection pumps and larger diaphragm pumps such as those used for heat trace. EPA should not propose to regulate low volume chemical injection pumps but should instead solicit comment on control options and cost effectiveness that apply to low volume chemical injection pumps versus larger diaphragm pumps. EPA would receive data showing it would not be practical to route chemical injection pumps to a control device and perhaps costly to potentially require a solar option for a large diaphragm pump.

3. Combustion controls should only be required if a control is required for another source. Emissions from pneumatic pumps alone cannot justify the installation of a flare because FILL IN. Additionally, if a storage vessel control can be removed when uncontrolled emissions are consistently below 4 tpy VOC, it is important that pneumatic pump control provisions not be written to prohibit removing this control. At a minimum, a request for comment on this issue should be provided in the preamble.

4. EPA should ensure that glycol recirculation pumps for glycol dehydrators are exempted from any pneumatic pump requirements. Emissions route through the still vent which is generally regulated through Subpart HH.

Compressors

1. Many well site compressors are rental units on site for periods of several days to several months or even longer. Because of the irregularity of service time on location, rod packing replacement schedules will be complicated to manage as maintenance is usually done by the rental vendor not the operator and any compressor moving site to site with different operators will make it difficult to track operating hours between rod packing replacement. EPA should take comment with respect to exempting well site compressors that are on site for less than 12 months which would be consistent with stationary source exemptions for engines.

2. EPA cannot justify regulating reciprocating compressors at well sites. In its July 2011 Technical Support Document for Subpart OOOO (EPA-453/R-11-002), EPA rightly determined that the VOC Cost Effectiveness for rod packing replacement technology for compressors at well sites was approximately $56,000/ton even with methane savings included. Methane Cost Effectiveness was approximately $15,500/ton. For all of the other O&G sectors (Gathering and Boosting, Processing, Transmission, and Storage) the VOC Cost Effectiveness was from 15 to 200 times <u>less</u> $/ton, which simplified the decision to regulate compressors in those sectors. Nothing has changed from the previous determination so a different result is not justified. Compressors at well sites operate at much lower first stage pressure than those at gathering/boosting,

processing, transmission, etc. and have smaller rod diameters; therefore, they inherently leak much less gas through rod packing. In addition, unless it is operating as a gathering line compressor, in most instances, shutting down a compressor at a well site requires the well(s) production to be shut-in, which is a cost not previously factored into the Subpart OOOO cost analysis.

3. EPA asked the SERs directly what might constitute a "small compressor" and other types of compressors. For informational purposes only, the simplest option for defining "small compressor" is to be consistent with the small engine threshold of <500 hp for engines (as discussed in the final rule preambles) in 40 C.F.R. Part 63, Subpart ZZZZ (see 69 Fed. Reg. 33,477 for major sources and 73 Fed. Reg. 3,583 for area sources).

4. Also, not all engines have compressor packing, and thus those engines cannot comply with the requirements of NSPS OOOO. Most of the currently manufactured examples (listed below) are small units that are typically utilized at well sites. (e.g., CompressCo's Gas Jack compressors that where originally made from a Ford V8 cylinder block and use one bank as power pistons and the other bank for compression). EPA should request comment on appropriate exemptions based on certain compressor designs.

Equipment Leaks

1. EPA asked questions about other technologies for leak detection beyond method 21 or an optical imaging camera. During the conference call, TXOGA mentioned that soap bubbles should be considered a viable technology. While larger operators can spread the cost of an IR camera across hundreds of well, small entities with only a handful of wells or less will have a much higher cost of implementation per site than larger operators. Soap bubbles are an effective technique at finding leaks, particularly if the goal is simply find and fix. It would be another option to keep cost down for small operators. EPA should at least seek comment on the use of soap bubbles as an alternative technique to find and fix equipment leaks.

2. In the cost effectiveness analysis, EPA should consider or seek additional input on a comprehensive list of cost items that would be incurred by the SERs when repairing a leak identified in the survey.

3. The cause of a leak and the type of repair required vary widely. Some repairs can be very costly, even cost-prohibitive. EPA should seek input on cases in the oil and gas industry, especially for SERs, where cost for repair is unreasonably high, and consider establishing exemptions for such cases.

4. Leak detection equipment can detect very minute leaks, which may not be cost-effective to repair. EPA should seek input on how to establish criteria for exempting small leaks from repair requirements.

5. EPA should provide flexibility that allows operators to make a site-specific determination when a repair is or is not appropriate.

Thank you for the opportunity to provide comment. Should you have additional questions, please contact me at mruckel@txoga.org or (512) 617.8892.

Sincerely,

Mari V. Ruckel

Mari Ruckel
Vice President
Government and Regulatory Affairs

COMMENTS OF UNITIL
July 6, 2015

ON US EPA OPTIONS FOR EMISSION STANDARDS FOR NEW AND MODIFIED SOURCES IN THE OIL AND NATURAL GAS SECTOR

As Presented at June 18, 2015 Small Business Advocacy Review Meeting And Supplemental Material June 26, 2015

Unitil respectfully requests consideration of the following comments on the options U.S. EPA is considering for the upcoming proposed PCB Use Authorizations Update Rule, as presented during the Small Business Advocacy Review (SBAR) Pre-Panel Outreach Meeting held on Wednesday, December 4, 2013.

In this SBAR proceeding, EPA is seeking information regarding the potential impact of its proposed rule changes on small businesses and other small entities as defined by the Small Business Administration's (SBA) size regulations. Unitil operates a small, investor-owned gas and electric utility serving customers in Maine, Massachusetts and New Hampshire, and a natural gas pipeline in New England that qualifies as a small natural gas transmission pipeline under SBA's size regulations.[1]

These comments focus on the potential impact of U.S. EPA's contemplated revisions to the new source performance standards (NSPS) for the natural gas sector under 40 C.F.R. Part 60, Subpart OOOO, particularly relating to natural gas transmission facilities.

Gas Distribution

Unitil is pleased to see that EPA is *not* proposing costly, mandatory NSPS for methane or volatile organic compound (VOC) emissions from natural gas distribution systems. EPA has recognized the continuing downward trend in methane emissions from the distribution sector based on voluntary process improvements and pipe replacement programs. In light of this progress, we understand EPA will create incentives for further distribution reductions through an enhanced Natural Gas STAR program to be proposed later this summer.

Compressors

Reciprocating Compressors – Alternative option / flexibility for rod packing replacement: Subpart OOOO currently includes prescribed maintenance for reciprocating compressor rod packing replacement. The original rule requires

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1 The Small Business Administration (SBA) has established size standards in 13 C.F.R. section 121.201 identifying small businesses in specific sectors identified by NAICS codes, pursuant to the Small Business Act. Under the SBA size regulations, Unitil qualifies as a small natural gas distribution utility with less than 500 employees (NAICS Code 221210), a small electric power distribution utility (NAICS Code 221122), and it operates a small natural gas transmission pipeline with annual receipts less than $27.5 million (NAICS Code 48621).

replacement every 26,000 operating hours or three years if operating hours are not monitored. A recent amendment added an option to recover and re-use the gas from rod packing vent lines. EPA should add another work practice option that provides flexibility while ensuring performance.

Rod packing is not always the sole source of excessive leakage. Unitil recommends that EPA should include "condition based maintenance" of the equipment, since other compressor cylinder issues could be responsible for an excessive leak. EPA could also include incentives to use low emission rod packing.

EPA should also be aware that gas recovery could create safety concerns.

As EPA is aware, some leakage is expected from reciprocating compressor rod packing. Prior to EPA's development of Subpart OOOO, some operators used a "condition based maintenance" program to determine when to perform rod packing or other maintenance. With this approach, the rod packing leak rate is periodically monitored, and an increase in rod packing leak rate above a defined level triggers rod packing maintenance.

An EPA Natural Gas STAR lessons learned document, "Reducing Methane Emissions from Compressor Rod Packing System,"[2] provides an example of condition-based maintenance practices. In the STAR program example, rod packing gas leaks are periodically monitored and the value of the incremental leaked gas (relative to post-maintenance/replacement leak rates) is tracked. When the incremental lost gas value exceeds the maintenance/replacement cost, the rod packing maintenance/replacement is cost-effective. This same philosophy can be applied in Subpart OOOO, but the maintenance decision should be based on a defined leak rate or change in leak rate over time indicative of degradation in rod packing performance. In California, the Air Resources Board (ARB) is contemplating similar regulations for reciprocating compressor rod packing leakage. Draft regulatory language from ARB allows condition based maintenance with a leak threshold of 2 scfm.[3]

Subpart OOOO should include condition based maintenance of reciprocating compressor rod packing as an optional alternative to the current standards. Flexibility to use condition based maintenance is warranted because rod packing performance may be acceptable when the prescribed time interval elapses. This approach avoids unnecessary costs and down time to replace packing that is still functional. In addition, it provides the ability to identify packing that degrades prematurely. Rod condition can also lead to leaks that will degrade packing at an accelerated rate and not be minimized by changing packing. A condition-based maintenance program allows operators to address underlying causes in a cost-effective manner.

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[2] http://www.epa.gov/gasstar/documents/ll_rodpack.pdf
[3] http://www.arb.ca.gov/cc/oil-gas/meetings/Draft_Regulatory_Language_4-22-15.pdf . §95213(e).

Reciprocating Compressors – Small compressors: Feedback from small entity representatives (SERs) was requested regarding an appropriate threshold for "small" compressors. For smaller applications, compressors are nearly always driven by a reciprocating engine. In national emission standards for hazardous air pollutants (NESHAP) and NSPS regulations for reciprocating internal combustion engines (RICE), EPA has already reached a conclusion regarding the size threshold for "small" units. A consistent threshold is recommended for Subpart OOOO to avoid unnecessary confusion regarding applicability of EPA regulations.

In the RICE NESHAP (40 CFR, Part 63, Subpart ZZZZ) and Spark Ignited Internal Combustion Engine NSPS (40 CFR, Part 60, Subpart JJJJ), 500 horsepower (hp) is used to categorize "small" units versus larger units. EPA discussed the basis for this decision in the preamble to the June 2004 NESHAP as well as January 2008 NESHAP amendments. The ARB draft regulatory language also uses 500 hp as the threshold for small versus large compressors. Since compressors in oil and gas operations subject to Subpart OOOO will be driven by reciprocating engines subject to Subpart ZZZZ, Subpart OOOO should use the same 500 hp threshold to define a small compressor.

Centrifugal Compressors – Reconstruction or Modification: For centrifugal compressors, EPA is focused on emissions associated with wet seal oil degassing vents. It is understood that new units will employ dry seals. However, an existing unit can become subject to an NSPS if modified or reconstructed. If that occurs for an existing unit with wet seals, Subpart OOOO compliance costs would be burdensome. Replacing wet seals with dry seals is cost prohibitive and not economically feasible. Recovering and reusing or flaring the vent stream would also add significant costs with minimal environmental benefit, and it is unlikely that such measures would be cost effective. EPA should contemplate and analyze the implications for an existing centrifugal compressor with wet seals that triggers NSPS applicability. EPA should consider including provisions in Subpart OOOO to ensure that applicability is not triggered for existing units. For example, EPA could clarify that a reconstruction analysis includes the compressor, driver, and peripheral support equipment when evaluating the cost of a comparable new facility.

Pneumatic Controllers

Pneumatic controller regulation is not warranted for transmission and storage operations because emissions are over-estimated: It is likely that EPA is considering adding requirements for "low bleed" pneumatic controllers for the transmission and underground storage (T&S) segments. It is not likely that such a requirement would result in meaningful reductions. For example, the EPA estimate of T&S pneumatic controller emissions in the annual GHG inventory is based on the 1996 EPA-GRI project reports. Emissions are over-estimated because current operations are more likely to use low bleed pneumatics or air systems.

Information from Subpart W of the GHG Reporting Program and recent studies indicate emissions from pneumatic controllers in T&S operations are significantly lower than estimates based on 20-year old data. Regulating pneumatic controllers in the T&S

segments is not warranted because meaningful reductions would not be realized. If this action is being considered, EPA should carefully assess current emissions and the emission reductions that are likely to be realized from regulation.

Unitil appreciates the opportunity to comment.

Respectfully,

Thomas Murphy
Manager, Environmental Compliance & Business Continuity
Unitil Corporation
6 Liberty Lane West
Hampton, NH 03842
murphyt@unitil.com

cc: Pamela A. Lacey
American Gas Association
placey@aga.org

WESTERN ENERGY
ALLIANCE

July 6, 2015

Nicole Owens
Director, Regulatory Management
U.S. Environmental Protection Agency
1200 Pennsylvania Ave. NW
Washington, DC 20460

Dear Ms. Owens:

Western Energy Alliance, in its role as a Small Entity Representative (SER), respectfully submits the following comments to the Small Business Advocacy Review (SBAR) Panel for the EPA rulemaking *Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector*. EPA is soliciting SER input for its SBAR Panel to offer the perspective of small entities that will be required to comply with EPA's forthcoming rulemaking.

Western Energy Alliance represents over 450 companies engaged in all aspects of environmentally responsible exploration and production of oil and natural gas in the West. The Alliance represents independents, the majority of which are small businesses with an average of fifteen employees.

EPA Has Not Provided Adequate Time for Review

As we commented during the pre-panel process, we believe that EPA has not provided adequate information for SERs to thoroughly review the cost and impacts on small entities, which limits the scope and specificity of our input. On June 18th, EPA provided SERs with unsupported cost estimates for a wide range of emission control strategies that lacked any background information on the assumptions, sources, and decisions behind those cost estimates.

Analysis of the cost information is impossible due to the many assumptions made by EPA and lack of supporting information. Therefore, we request clarification from EPA on the supporting information behind its cost assumptions. As an example, the representative gas analysis information used in the oil well completion calculations assumes a 46.732% methane concentration by volume for associated gas. EPA references a memorandum in support of this estimate, yet the memorandum itself does not provide any data for the basis of this assumption.[1] There are numerous other points that require clarification before we can determine the accuracy of EPA estimates, therefore we request an

[1] *Memorandum to Bruce Moore EPA/OAQPS/SPPD:* *Composition of Natural Gas for use in the Oil and Natural gas Sector Rulemaking*, Docket ID EPA-HQ-OAR-2010-0505-0084, Heather Brown, , July 2011.

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additional meeting with EPA once participants have been given adequate time to review the material presented on June 18th.

On June 23rd, EPA submitted its draft rules to the Office of Management and Budget (OMB) despite not having completed the SBAR panel process. It is our understanding that the SBAR panel is designed to inform rulemaking and provide information on how EPA can avoid disadvantaging small businesses. However, by releasing the rule for OMB review prior to receiving SER input, it does not appear that EPA intends to take the SBAR panel's recommendations into account. This action undermines the SBAR process and demonstrates a lack of concern over the rule's impact on small businesses.

Leak Detection and Repair Program Concerns

In our initial comments, we expressed significant concern regarding the inclusion of a Leak Detection and Repair (LDAR) program in the forthcoming regulations. In particular, we provided information on why Colorado's Regulation 7 LDAR program is not suitable as a national model. In response to EPA's request for additional information on the Colorado model, we draw EPA's attention to an economic analysis conducted by Louis Berger Group to review the Colorado Department of Public Health and Environment (CDPHE) analysis.[2]

Louis Berger evaluated the impact of Colorado's LDAR program on marginal wells and determined that the stringent LDAR program implemented by CDPHE has high compliance costs that would make many marginal wells un-economic. Louis Berger's analysis showed that 55% of active wells in Colorado produce less than two barrels of oil per day (bopd). In 2013 when the analysis was conducted, the economic limit at which production revenues no longer cover lease operating expenses was 0.43 bopd. Under Colorado's LDAR program, that number is estimated to be more than double, at 1.05 bopd. Over the life of currently producing wells, this additional burden will ultimately result in 128 million barrels of oil being left in place, $11.6 billion in lost revenue to producers, $2.3 billion in lost royalties, and $579 million in lost severance taxes in Colorado. Given the current oil price environment, the break-even threshold is likely even higher than 1.05 bopd, which will result in even greater production losses and revenue losses. The burden of compliance on marginal wells will be especially detrimental for small producers who may not have a large asset base to offset compliance costs.

Colorado's LDAR program poses numerous compliance issues in addition to the loss of marginal wells. It imposes overly strict inspection schedules that offer minimal environmental benefit. In the overwhelming majority of instances, after initial leaks are found and fixed, the rate of leak frequencies drops dramatically. The benefits of subsequent rounds of inspection diminish greatly over time, which further reduces the cost-effectiveness of the program. However, CDPHE failed to account for this diminishing

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[2] *Testimony to Colorado Air Quality Commission of Regulation 7 Economic Impact Analysis*, Lisa McDonald, February 19-23, 2014, p. 39-55.

return in its cost analysis and as a result, created a flawed rule. This problem is compounded in areas where locations are remote and difficult to access. Long travel times create additional expense, produce vehicle emissions that negate any possible air quality benefits and rarely detect any leaks in later years. Additional costs that must be accounted for include the:

- Time and resources to fulfill LDAR reporting requirements, either in-house or third-party
- Cost for parts necessary to repair leaks
- Cost of time to repair leaks
- Cost of time to re-camera the leaking equipment after repairs to ensure no leaking
- Time to complete paper work to document completed and effective repairs
- Lost production from equipment downtime during leak repairs
- Cost of infrared cameras and maintenance of camera, factoring in the length of warranty
- Operator or third-party vehicle maintenance to perform LDAR
- Cost to identify accurate component counts used for LDAR, as well as other functions, such as permitting.

In many cases, the additional resources required for an extensive inspection program will disproportionately impact small businesses that do not have large dedicated compliance groups. In the June 18th presentation, EPA discussed "reduced frequencies" of inspections. We strongly encourage EPA to clarify what this means in a follow-up presentation and allow small entities to take that information into consideration. In the original New Source Performance Standards Subpart OOOO, EPA avoided overly-prescriptive inspection requirements and instead allowed monthly or quarterly audio, visual, and olfactory (AVO) inspections, which may be an approach to consider for oil well completions. AVO inspections are as effective in finding the leaks as the infrared camera inspections but are more cost effective.

EPA should also consider the timing of repairs following leak detection. In some instances, it may be counterproductive to repair a leak right away. For safety concerns, some repairs may require well blowdowns that result in far greater emission releases than the initial leak itself. An LDAR program must provide regulatory flexibility to allow for common-sense operational considerations.

Pneumatic Controls, Pneumatic Pumps and Compressors

In slides presented on June 18th, EPA estimated the proposed controls would cost $200-$8,000 depending on the process chosen. However, these cost estimates appear to only consider the cost of the equipment itself. EPA does not acknowledge in its presentation or its white papers the cost of the time consumed and verification of repairs, which disproportionately burdens small entities with limited resources and staff. Controls for gas pneumatics also would likely not be cost-effective based on the volumes of emissions recovered. EPA also proposes instrument air as a substitute for gas pneumatics; however this is not practical due to the remote location and lack of power at many upstream locations. EPA needs to revise its compliance options and cost estimates to reflect the full implementation cost.

The exemption for well-site compressors should remain unchanged. The existing rules for non-wellsite compressors are aligned with prevailing compressor maintenance practices, but adding small compressors would dramatically expand the scope of this rule. A one-size-fits-all compressor rule would likely pull in far more than the 50-100 sources anticipated by EPA. If EPA expands the rules to cover small wellsite compressors, it will need to dramatically revise the estimates and consider those additional impacts.

Oil Well Completions

In the June 18th presentation, EPA asked for additional information regarding exemptions from oil well completions based on production thresholds and gas-to-oil ratios (GOR). We do not recommend using production-based thresholds or GOR for exemptions from oil well completion requirements because this information is not available at the pre-fracturing stage. It would be more effective to base exemptions on field-wide production in barrels per field or company size in revenue or number of employees, rather than GOR or well production thresholds

We also question EPA's analysis of the oil well completion emission benefits. In its analysis, EPA states that methane is 46.732% of the volume of gas produced during a well completion. Based on initial surveys of operators, this number is highly inaccurate. Given the limited time provided by EPA, we have not been able to conduct extensive data gathering. However, our preliminary analysis suggests a more representative range would be 40-80% methane with many basins producing gas that is over 60% methane. It is important to note that the remaining gas volume is not entirely volatile organic compounds (VOCs). Gases like ethane, carbon dioxide, and nitrogen can make up significant volumes of produced gas. In many cases, VOC emissions are likely 10-30% of total volume. Again, these data are only preliminary due to the lack of time EPA has given us to review and gather information, but it would appear that EPA's oil well completion numbers need substantial revision.

Serving to further complicate matters, EPA presents information in an annualized format with the cost savings already included, which makes it difficult to pull apart the assumptions. In order to provide EPA with more accurate oil well completion information, we surveyed members regarding their oil well completion practices. Given the extremely limited timeframe and the large amount of data needed, this table must be considered preliminary and requires further information before it can be treated as complete.

Oil Well Completion Data

	DJ Basin	Williston Basin	Powder River Basin
Days to complete (flowback)	2-7	2-7	21-28
Additional green completion cost per day ($/day)	$2,000-$7,200	$3,500-$10,800	$8,400
Average volume of gas produced during completion (MCF/day)	1,500-3,000 MCF	300-2,500 MCF	100-1,500 MCF
Average % gas currently flared during completion	50-80%	50-80%	90-100%
Average % gas currently sold during completion	20-50%	20-50%	0-10%
Average % gas currently vented during completion*	< 1%	< 1%	< 1%
Methane gas composition %	40-80%	50-70%	70-80%
VOC gas composition %**	10-30%	10-30%	10-20%

The data show that gas is largely controlled through flaring or capture and sales. For safety reasons operators vent as little gas as possible. Regulations seeking to minimize venting for oil well completions are redundant under current industry practices. Also of note is the high variability of well flowback times and costs per green completion. A one-size-fits-all cost analysis will almost certainly fail to capture the highly variable nature of well completion operations. Small operators also tend to be on the high end of completion costs. They typically conduct completions less frequently and lack the purchasing power to get the discounted prices service companies offer to larger operators, therefore a one-size-fits-all cost estimate would likely not adequately represent the cost burden faced by small operators.

The high variability of well completion practices underscores that it is not possible to conduct the comprehensive analysis that is needed for these complex operations within the time EPA has provided. EPA should provide SERs with more time to gather meaningful input on how to classify oil well completion thresholds and determine the cost of reduced emission completions. We strongly recommend that EPA hold another review session for SERs after they have been given adequate time to gather this necessary information as EPA clearly does not have enough information at this point to make an informed decision on how to define oil well completion exemptions. Oil well completion controls, if applied too broadly, could greatly disadvantage small producers that may not be able to absorb the incremental costs of those controls.

Upstream Methane Control Strategies are Not Cost-Effective

We raised concerns over targeting upstream methane emission sources in our pre-panel comments, but these concerns are still not adequately addressed in the information presented by EPA to date. A methane control strategy for upstream oil and natural gas operations threatens to skew the economic hardship towards small upstream operators without offering cost-effective reductions. Instead, a control strategy aimed at achieving the greatest emission reductions at the lowest incremental cost must focus on the natural gas processing, transmission and storage sectors. EPA's own series of white papers on emission sources notes that upstream methane emissions from compressors are 86,000 MT at gas production sites versus 1,985,000 MT from gas processing, transmission and storage sites. These downstream operations emit at 23 times the rate of upstream sites and clearly present the opportunity to achieve greater emission reductions. Upstream compressor controls would be extremely burdensome for many small operators given the significant capital expense associated with compressors and would clearly miss the bulk of emission reduction opportunities, which are found downstream.

According to a study by the University of Texas, Austin, methane emitted from all upstream source categories at natural gas production sites represents just 0.42% of gross natural gas production volumes.[3] Chasing a small source of emissions is not cost-effective, and will be particularly burdensome on small producers. In addition, it is counterproductive to the President's overall climate change goals, as greater use of natural gas, particularly for electricity generation, is one of the main reasons for decreases in overall U.S. greenhouse gas emissions. Putting in place expensive requirements to capture a small source of emissions at the upstream sector will result in less natural gas production, higher prices for consumers, and hence, less climate change benefit.

Thank you for considering these comments and recommendations. We appreciate the opportunity to participate in the process. However, to provide meaningful input we require additional time, data and clarification from EPA regarding the cost estimate assumptions in its white papers and presentations. EPA has not satisfactorily provided the information needed to fully address the impacts of forthcoming regulations on small businesses. We look forward to additional details so that we can help EPA understand the full cost implications.

Sincerely,

Kathleen M. Sgamma
Vice President of Government & Public Affairs

[3] "Measurements of methane emissions at natural gas production sites in the United States," *Proceedings of the National Academy of Sciences of the United States of America Vol. 110 No. 4*, Allen et. al., August 19, 2013.

Testimony of Lisa A. McDonald PhD

Senior Economist, The Louis Berger Group, Inc.

Economic Impact Analysis

Background & Experience

- Twenty years of experience conducting economic studies for federal, state, and private clients
- Completed several studies/analyses focused on issues related to the oil and gas industry in Colorado, Wyoming, Utah, and Texas
- Ph.D. in Mineral Economics from the Colorado School of Mines

Summary of Expert Opinions

- The Proposed Rules are:
  - Significantly more expensive than estimated by Division
  - Significantly more expensive ($1,000/tank higher) outside the NAA
  - Not cost-effective at the proposed frequencies of LDAR monitoring

- Proposed Rules would result in:
  - 125.1 million barrels of oil left in the ground
  - $1.9 billion in lost revenue (discounted)
  - $374 million in lost royalties (discounted)
  - $80 million in lost severance taxes (discounted)

Methodology and Approach

- Considering Effectiveness of LDAR in EIA
  - control technology effectiveness ≠ LDAR effectiveness (*see* B. Ross and J. Christopher)
- Must appropriately account for all LDAR components in cost analysis (*e.g.*, record keeping, reporting, set up, camera training, repair and re-monitoring)
- Our cost estimates are based on current data and tailored to the various provisions of the Proposed Rules

LDAR Cost Comparison

Item	Total Annual Cost (LB)	Total Annual Cost (Division)	Total Cost Per Facility/ Tank (LB)	Total Cost Per Facility/ Tank Costs (Division)	Cost Per Ton of VOC Reduced (LB)	Cost Per Ton of VOC Reduced (Division)
STEM – Initial Yr	$76.0M	$28.1M	$14,305	$5,301	$1,233	$527
STEM – Subsequent Yrs	$73.7M	Same as above	$13,867	Same as above	$5,079	Same as above
WPF – LDAR Initial Yr	$90.4M	$23.8M	$11,101	$2,934	$5,684	$1,259
WPF LDAR – Subsequent Yrs	$51.1M	$22.2M	$6,275	$4,171	$17,015	$1,580
CS – LDAR Initial Yr	$8.3M	$1.5M	$41,664	$7,650	$4,674	$1,382
CS – LDAR Subsequent Yrs	$5.3M	Same as above	$26,227	Same as above	$12,528	Same as above

*Costs do not include product savings.

Source: JIWG-Revised Final EIA; APCD-REB R7.finalEIA

Well Production Facility LDAR Assumptions

Assumption	Louis Berger	Division
Uncontrolled Emissions	2.56 TPY	4.6 TPY (NAA) 3.9 (ROS)
Number of components	592	1,238
LDAR Control Effectiveness	Initial Emission Reductions: 75.3% with annual; 76.5% quarterly; 80% with monthly; Subsequent reductions: 23.5% of initial reductions	Constant annual emission reductions: 40% annual; 60% quarterly; 80% monthly
Inspection Cost	Labor: $150/hr Supervision: $100-$200/facility/year Record Keeping/Reporting: $1,530-$3,060/facility/year Travel:$30/inspection (NAA) for fuel and per diem; $40/inspection (ROS)	$101/hr, includes inspection, supervision, travel, record keeping, reporting, overhead, fringe as well as annualized capital costs

Source: JIWG-Revised Final EIA; APCD-REB R7.finalEIA

Well Production Facility LDAR Assumptions (2)

Assumption	Louis Berger	Division
LDAR Program Set up costs	$100/Facility	Not Included
AVO Inspection Costs	12 inspections/year; 0.5 hours/inspection; $100/hour. Supervision: $100/facility. Training costs: $7,500/year/300 facilities	Not Included
Re-monitoring	All inspections would require re-monitoring in initial year; between 64 and 70% of inspections would require re-monitoring in subsequent years	Not Included
Camera Training Costs	$7,500/year/100 facilities	Not included

Source: JIWG-Revised Final EIA; APCD-REB R7.finalEIA

Well Production Facility LDAR Assumptions (3)

Assumption	Louis Berger	Division
Repair Costs	75% of leaks can be repaired online with 1 hour of repair time; 25% of leaks would need to be shut-down with 4 hours to repair leak Hourly rate: $75	Repair time: 0.17 to 16 hours/component; average of 0.73 hours/repair Hourly rate: $66.24
Camera Life	5 years	5 years
Camera Repair and Maintenance Costs	$12,500/year/camera	$7,500/year (included in annualized inspection costs)
Inspection time	4.75 hours/inspection in NAA 5.75 hours/inspection in ROS	3.4 hours/inspection in NAA 6.1 hours/inspection in ROS
Leak Rates – Initial Year	1.7%/inspection	1.18% for annual 1.77% for quarterly 2.36% for monthly
Leak Rates – Subsequent Years	0.4%/inspection	Same as above

Source: JIWG-Revised Final EIA; APCD-REB R7.finalEIA

Revised LDAR Costs for Well Production Facilities

Tanks Uncontrolled Emissions	Total Costs, Initial Years	Total Costs, Subsequent Years	Total Cost Per Ton, Initial Year	Total Cost Per Ton, Subsequent Years
less than 6 TPY	$14,998,781	$2,980,398	$2,745	$5,454
6 to 12 TPY	$7,451,523	$5,894,163	$2,736	$9,197
12 to 50 TPY	$36,781,875	$23,950,936	$6,430	$17,794
greater than 50	$31,211,573	$18,299,547	$15,583	$38,829
Total (Revised EIA)	$90,443,751	$51,125,043	$5,684	$17,015
Total (Final EIA)	$136,686,370	$58,151,950	$8,590	$19,354

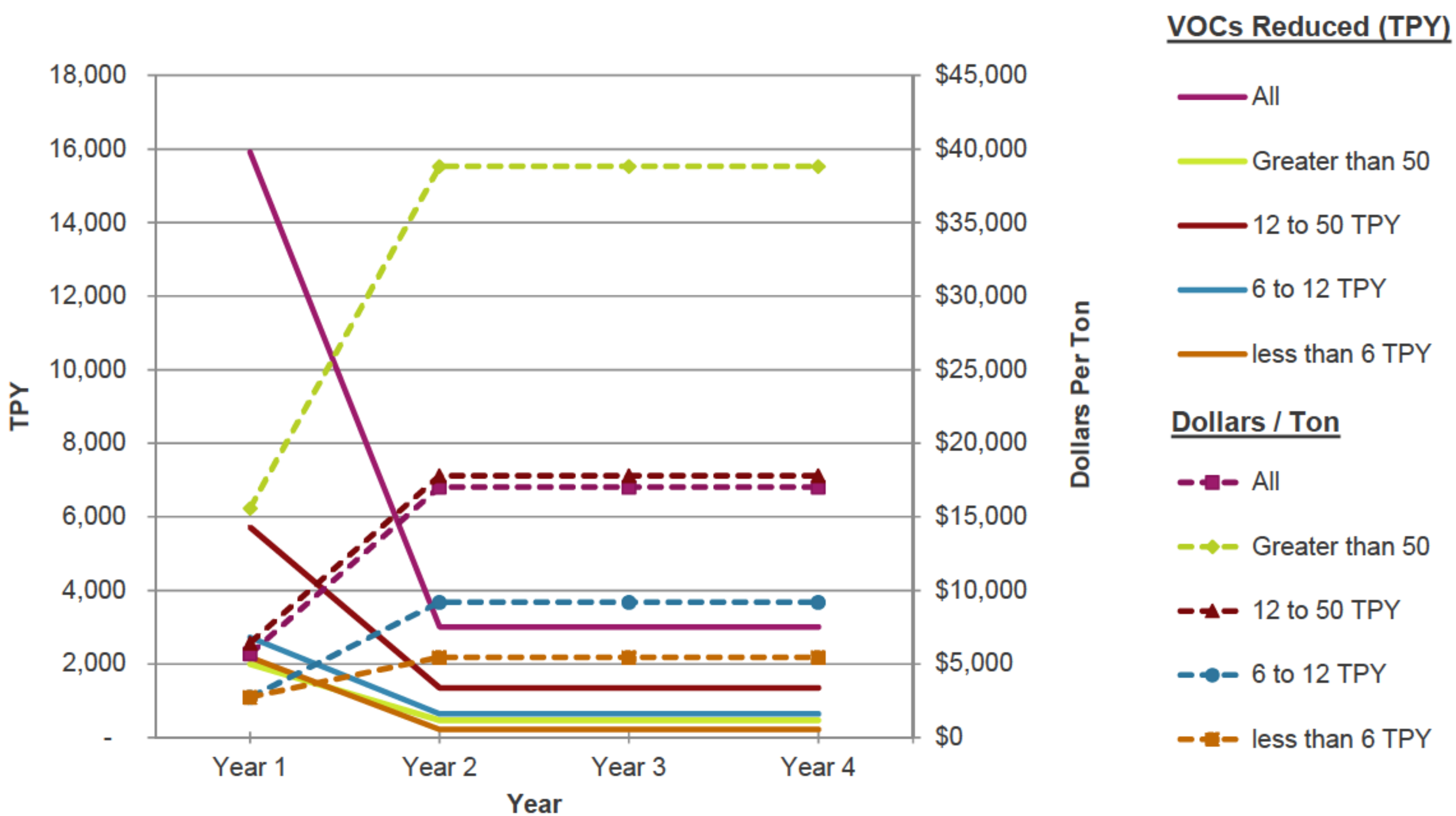
Source: JIWG-Revised Final EIA

Geographic Differences – LDAR Annual Costs per WPF

Uncontrolled VOC At Tank Battery	Initial Year NAA	Initial Year Rest of State	Subsequent Years NAA	Subsequent Years Rest of State
Less than 6TPY	$5,195	$5,513	$1,051	$1,051
6 to 12 TPY	$5,198	$5,522	$4,104	$4,394
12 to 50 TPY	$12,451	$13,722	$8,073	$9,212
Greater than 50 TPY	$30,971	$36,425	$17,837	$22,895

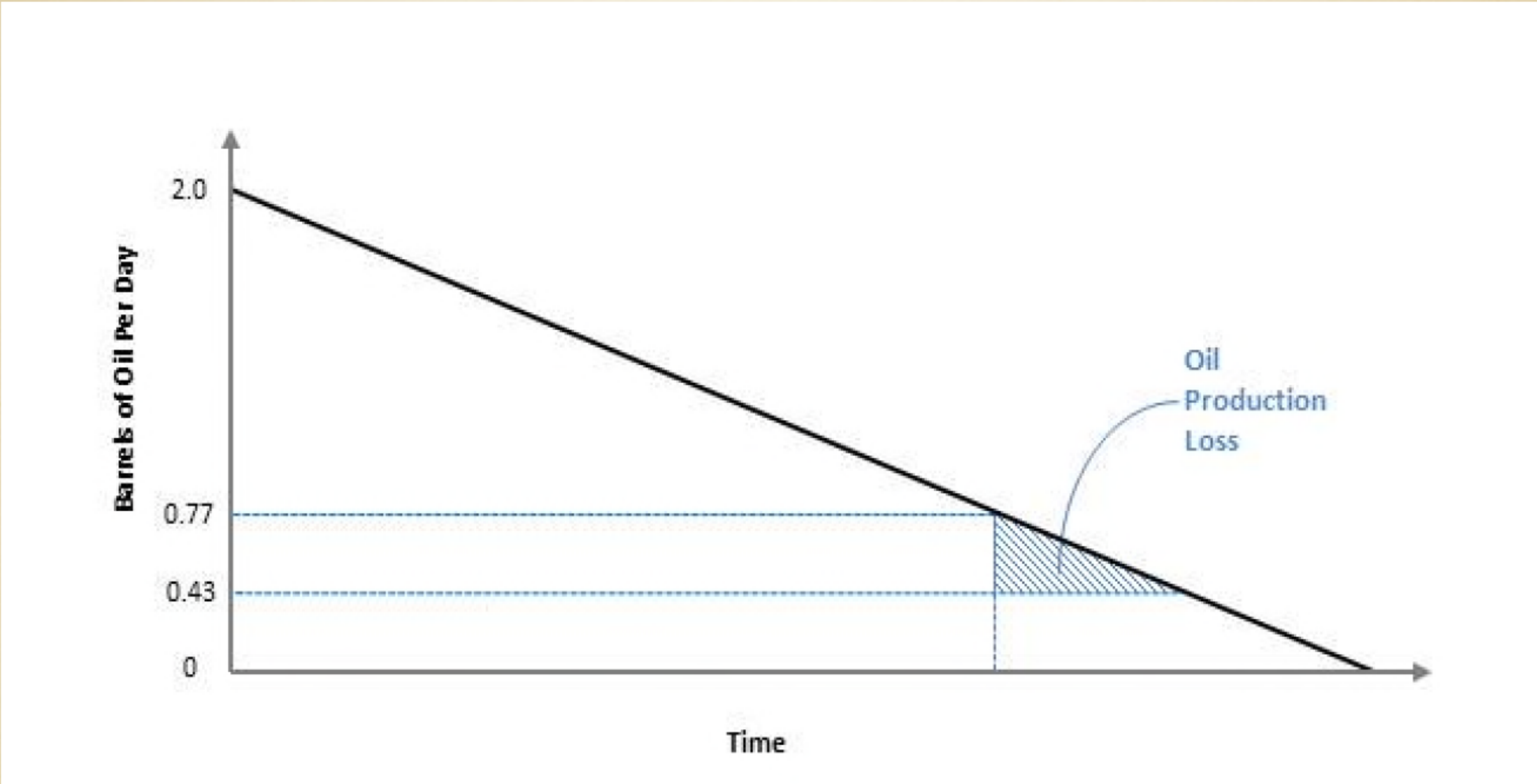
Source: JIWG-Revised Final EIA

Monitoring Frequency - WPF



Source: JIWG-Revised Final EIA

Increasing Costs will Change the Economic Limit for Marginal Wells



Source: JIWG-Revised Final EIA

Marginal Well Analysis

- 55 percent of active wells in state produce less than 2 BOPD
- Current economic limit where production revenues no longer cover lease operating expenses is 0.43 BOPD
- Over time an estimated 125.1 million barrels of oil would be shut in due to increased costs of proposed rules

Item	Total (Not Discounted)	Total (Discounted at 10% over 60 years)
Production Lost (BO)	125.1 million	
Value of Lost Production ($)	$11.3 billion	$1.9 billion
Lost Royalties ($)	$2.3 billion	$374.0 million
Lost Severance Taxes ($)	$562.9 million	$80.1 million

Source: JIWG-Revised Final EIA

Value of Recovered Product

	Louis Berger Initial Year	Louis Berger Subsequent Years	Division Estimates All Years
Value of Recovered Product from Well Production Facilities	$12.5M	$2.4M	$4.5M
Percent of WPF Repair and Re-monitoring Costs	28.5%	19.2%	77.6%
Percent of Total LDAR Costs (not including value recovered)	13.8%	4.7%	20.3%

Source: JIWG-Revised Final EIA; APCD-REB R7.finalEIA

Final Opinions

- Fundamental flaws in Division's approach:
  - Fails to consider diminishing returns of LDAR
  - Improperly excludes program set up, AVO, camera training costs, and re-monitoring costs
  - Underestimates other program costs
- The costs estimated by Louis Berger are <u>significantly</u> higher than those estimated by the Division
- The increased regulatory costs will affect smaller producers more significantly than larger producers/emitters
- The increased costs will disproportionally impact producers outside the NAA