Message

From: Lee Fuller [lfuller@ipaa.org]
Sent: 12/21/2017 9:32:29 PM
To: Schwab, Justin [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=eed0f609c0944cc2bbdb05df3a10aadb-Schwab, Jus]
Subject: EPA Oil and Natural Gas Production Regulations -- Low Producing Wells
Attachments: IPAA-AXPC Coalition Comments on NODA with Attachments.pdf

Justin,

In the past, I've sent you various comments that IPAA has filed on the EPA methane/VOC regulatory package – NSPS Subparts OOOO and OOOOa and Control Techniques Guidelines for existing oil and natural gas production facilities in Ozone Nonattainment areas. Attached here are comments submitted on the recent EPA Notice of Data Availability proposal to alter compliance dates on several elements of Subpart OOOOa.

In general, these comments support EPA's proposal to extend compliance deadlines. One that is addressed specifically is the fugitive emissions program. In particular, the comments address the implications of EPA's decision to apply the requirements to low producing wells (15 b/d and less of oil; 90 mcfd of natural gas) after initially proposing an exclusion for these wells.

Part of the issue with EPA technology and cost effectiveness determinations for the fugitive emissions program, which also applies to other requirements but less clearly, involves understanding the differences between production operations when wells are large producers and when they are low producing wells. EPA bases its analyses on large production facilities. However, because the fugitive emissions program places a perpetual cost on the operation, the cost effectiveness is very different when the well is new – at 5000 mcfd, for example – than it is when at the average low producing well rate of 22 mcfd.

EPA has the authority under the Clean Air Act to create subcategories when it structures NSPS. The oil and natural gas production industry is a good example of when it should use this authority. Technology and cost effectiveness determinations should be based on realistic operating conditions and the economics of these low producing wells.

IPAA would recommend that EPA – as it revisits the methane/VOC regulations for oil and natural gas production facilities – creates a low producing well subcategory. In early 2018, I'd like to discuss this concept and how to approach it with you.

Thanks,

Lee Fuller

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December 8, 2017

The Honorable Scott Pruitt, Administrator
US Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

VIA E-MAIL AND E-FILING

Re: Environmental Protection Agency's Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements at 82 Federal Register 51788 (November 8, 2017)

Docket ID No. EPA-HQ-OAR-2010-0505

Dear Administrator Pruitt:

The following comments are submitted on the above-referenced proposed rule and notice of data availability ("NODA") on behalf of the following national and state trade associations: the Independent Petroleum Association of America ("IPAA"), American Exploration & Production Council ("AXPC"), Domestic Energy Producers Alliance ("DEPA"), Eastern Kansas Oil & Gas Association ("EKOGA"), Illinois Oil & Gas Association ("IOGA"), Independent Oil and Gas Association of West Virginia, Inc. ("IOGA-WV"), Indiana Oil and Gas Association ("INOGA"), International Association of Drilling Contractors ("IADC"), Kansas Independent Oil & Gas Association ("KIOGA"), Kentucky Oil & Gas Association ("KOGA"), Michigan Oil and Gas Association ("MOGA"), National Stripper Well Association ("NSWA"), North Dakota Petroleum Council ("NDPC"), Ohio Oil and Gas Association ("OOGA"), Oklahoma Independent Petroleum Association ("OIPA"), Pennsylvania Independent Oil & Gas Association ("PIOGA"), Texas Alliance of Energy Producers ("Texas Alliance"), Texas Independent Products & Royalty Owners Association ("TIPRO"), and West Virginia Oil and Natural Gas Association ("WVONGA") (collectively, "Independent Producers"). The Independent Producers have participated individually or through IPAA in most, if not all, of the rulemakings and associated litigation since the Environmental Protection Agency ("EPA" or "Agency") proposed to revise the New Source Performance Standards ("NSPS") for the Oil and Natural Gas Sector in August 2011. 76 Fed. Reg. 52,738 (Aug. 23, 2011). While most of the Independent Producers represent companies that engage in large volume hydraulic fracturing horizontal or unconventional drilling, a significant portion of their membership is also comprised of "mom and pop" operations that engage in some form of hydraulic fracturing as defined by EPA, generally involving vertical wells drilled into geological formations currently referred to as conventional wells. From the beginning of these rulemakings, most of the Independent Producers have tried to illustrate to the EPA that their "one-size-fits-all" approach to regulating this industry is inappropriate. The NODA represents another, necessary, opportunity to work with the EPA to tailor 40 C.F.R. Part 60, Subpart OOOOa ("Subpart OOOOa") to reduce the impact on the Independent Producers and their individual members while still providing adequate protection of the environment. The Independent Producers' Petition for Reconsideration submitted on August 2, 2016, to the EPA outlines the primary issues that should be addressed during the two-year time period set forth in the NODA.[1] As a result of various factors, including the regulatory burden, many individual members of the Independent Producers have not drilled a single well in the past five years. The two-year extension of compliance deadlines set forth in the NODA will have a tremendous benefit to the Independent Producers and their individual members, while having little to no negative impact on the environment. The proposed two-year time period is entirely appropriate for the Independent Producers to educate the new Administration on their concerns, as well as make the appropriate and necessary changes to current regulations. The following comments are generally organized according to the questions and topics set forth in the NODA. These comments include remarks from certain members of the Independent Producers who request anonymity while others are not concerned with being recognized. To the extent the EPA would like additional information regarding a particular comment, please contact me and I will serve as an intermediary to provide additional information.

GENERAL COMMENTS

A. Legal Basis for EPA Revision of Original Proposal

The Independent Producers concur that the EPA has adequate authority to pursue either a stay of an extension of implementation pursuant to the Agency's authority under both Clean Air Act ("CAA") Section 111 as well as the Federal Administrative Procedures Act ("APA") Section 705. Moreover, the EPA need only establish that the reasons for the new policy are sound.

> [T]he agency must show that there are good reasons for the new policy. But it need not demonstrate to a court's satisfaction that the reasons for the new policy are better than the reasons for the old one; it suffices that the new policy is permissible under the statute, that there are good reasons for it, and that the agency believes it to be better, which the conscious change of course adequately indicates.

[1] A copy of the Independent Producers' August 2, 2016 Petition for Reconsideration is attached for inclusion in the administrative record.

FCC v. Fox Television Stations, Inc., 556 U.S. 502, 515 (2009) (emphasis omitted).

In anticipation of commentary from environmental groups who will presumably object to a stay or extension, the Independent Producers remind the EPA of the holding in the *National Association of Home Builders* case in 2012. "The fact that the original [rule] was consistent with congressional intent is irrelevant as long as the amended rule is also 'permissible under the statute.'" *Nat'l Ass'n of Home Builders, et al., v. EPA*, 682 F.3d 1032, 1037 (citing *Fox*, 556 U.S. at 515). The petitioners acknowledge that, although they believe the original rule was better, the amended rule is permissible. Oral Arg. Recording at 17:40-:43. As *Fox* made clear, that "suffices" as far as the court is concerned. *Fox*, 556 U.S. at 515. As *Fox* noted, the Supreme Court has "neither held nor implied that every agency action representing a policy change must be justified by reasons more substantial than those required to adopt a policy in first instance." *Fox*, 556 U.S. at 514 (citing *Motor Vehicle Manufacturers Ass'n of the United States, Inc., et al., v. State Farm Mutual Automobile Insurance Co., et al.*, 463 U.S. 29, 42 (1983)). To the contrary, the *State Farm* case affirmed that "[a]n agency's view of what is in the public interest may change, either with or without a change in circumstances." *State Farm*, 463 U.S. at 57 (quoting *Greater Boston Television Corp. v. FCC*, 444 F.2d 841, 852 (D.C.Cir.1970)); *see Am. Trucking Ass'ns v. Atchison, Topeka & Santa Fe Ry. Co., et al.*, 387 U.S. 397, 416 (1967) (declaring that an agency, "in light of reconsideration of the relevant facts and its mandate, may alter its past interpretation and overturn past administrative rulings"). *Nat'l Ass'n of Home Builders*, 682 F.3d at 1037.

The Independent Producers generally feel that an extension, as opposed to a stay, is a more appropriate approach and more in keeping with the agency's discretionary authority under the two applicable statutes.

B. Reinstate Low Production Well Exemption

Perhaps the single most important issue to many of the Independent Producers is the need to reinstate the low production well exemption from the fugitive emissions requirements (Leak Detection and Repair ("LDAR")) and extend the compliance deadline for two years while the exemption is reevaluated. The following comment was received from a small independent operator in Texas and is representative of many smaller companies across the country:

> I am a small operator of marginal oil wells and have been operating at a negative cash flow the last few years. My production facility has back pressure vent valves and I have passed recent Railroad Commission field inspections. My lease produces less than 15 barrels of oils per day or equivalent ("BOE") and adding an additional regulatory expense burden will force me to discontinue operations and plug and abandon the existing marginal wells.

It is that simple. The LDAR requirements on low production wells represents the death knell to many wells and has little environmental benefit. Application of the fugitive emissions program on low producing wells and on refractured existing wells should be delayed until the EPA can reconsider its position on these facilities

When the EPA proposed Subpart OOOOa, it excluded the application of its fugitive emissions requirements for low producing wells – oil wells producing 15 BOE or less and natural gas wells producing 90 mcfd or less. In finalizing Subpart OOOOa, the EPA withdrew the low producing well exclusion. It based this decision on a specious analysis of methane emissions by the Environmental Defense Fund ("EDF"). The Independent Producers petitioned the EPA to reconsider its action. The EPA granted portions of the Independent Producers' Petition for Reconsideration, including the removal of the low production well exemption on April 18, 2016. For the reasons set forth below, the EPA should, at a minimum extend the compliance deadlines for low production wells complying with the LDAR provisions as well as the reduced emission completions requirements as they apply to low production wells.

The impact of the fugitive emissions program falls more heavily on low producing wells than larger producing wells. Moreover, unlike other provisions of Subpart OOOOa, the fugitive emissions requirements are perpetual operating costs rather than initial capital costs. The EPA's regulatory analysis made no determination that addressed the differences in the cost effectiveness of its fugitive emissions program on low producing wells. Compounding this failure, the EPA's use of an inappropriate definition of modification in Subpart OOOOa is suppressing normal processes to extend the life of oil and natural gas production operations because these actions would trigger application of the fugitive emissions requirements.

Moreover, as the Independent Producers explained in their Petition for Reconsideration, the EPA's logic and reasoning in Subpart OOOOa is internally inconsistent. The EPA assumes that replacing equipment that increases production will increase emissions because of pressure and production. Yet, the EPA ignored that reality when it came to low production wells and indicated pressure and production did not play a role in emissions – and instead claimed that it was a function of the number of components and connections. That is manifestly unfair and the provisions need to be stayed or the compliance deadline needs to be extended until the EPA cannot only explain their inconstant logic, but also better understand the quantity of emissions from leaks at low production wells and the costs associated with the LDAR requirements, especially as they apply to small entities. The EPA previously recognized the legitimacy of this concern and granted an opportunity for notice and comment in the Administrator's letter to the Independent Producers, *et al.*, dated April 18, 2017. The following is a detailed explanation supporting this request.

When EPA finalized Subpart OOOOa, the rule included the following assertions:

Several commenters stated that the EPA should not exempt low production well sites because they are still a part of the cumulative emissions that would impact the environment. ***One commenter indicated that low production well sites have the potential to emit high fugitive emissions.*** (Emphasis added) Another commenter stated that low production well sites should be required to perform fugitive emissions monitoring at a quarterly or monthly frequency. One commenter provided an estimate of low producing gas and oil wells that indicated that a significant number of wells would be excluded from fugitive emissions monitoring.

Based on the data from DrillingInfo, 30 percent of natural gas wells are low production wells, and 43 percent of all oil wells are low production wells. The EPA believes that low production well sites have the same type of equipment (*e.g.*, separators, storage vessels) and components (*e.g.*, valves, flanges) as production well sites with production greater than 15 boe per day. Because we did not receive additional data on equipment or component counts for low production wells, we believe that a low production well model plant would have the same equipment and component counts as a non-low production well site. This would indicate that the emissions from low production well sites could be similar to that of non-low production well sites.

We also believe that this type of well may be developed for leasing purposes but is typically unmanned and not visited as often as other well sites that would allow fugitive emissions to go undetected. We did not receive data showing that low production well sites have lower GHG (principally as methane) or VOC emissions other than non-low production well sites. In fact, the data that were provided indicated that the potential emissions from these well sites could be as significant as the emissions from non-low production well sites because the type of equipment and the well pressures are more than likely the same. In discussions with us, stakeholders indicated that well site fugitive emissions are not correlated with levels of production, but rather based on the number of pieces of equipment and components. Therefore, we believe that the fugitive emissions from low production and non-low production well sites are comparable.

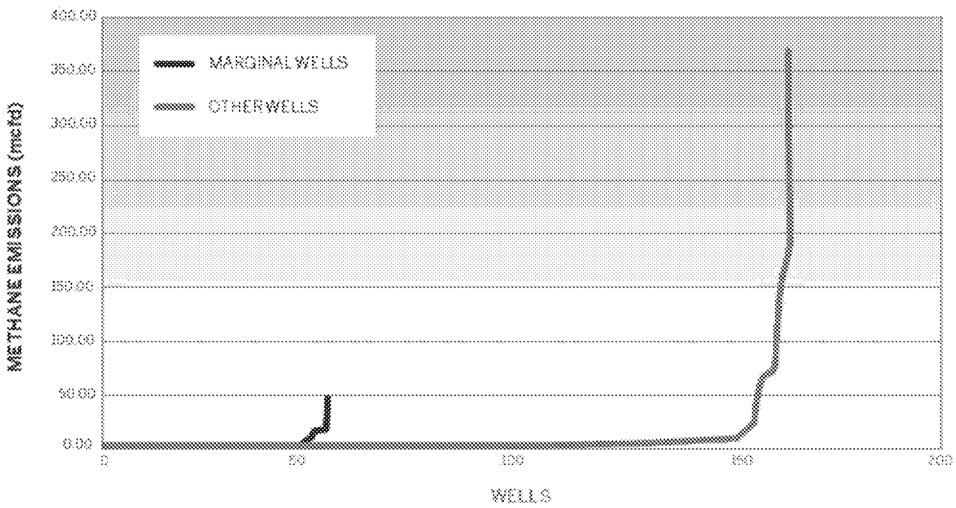
Based on these considerations and, in particular, the large number of low production wells and the similarities between well sites with production greater than 15 boe per day and low production well sites in terms of the components that could leak and the associated emissions, we are not exempting low production well sites from the fugitive emissions monitoring program. Therefore, the collection of

> fugitive emissions components at all new, modified or reconstructed well sites is an affected facility and must meet the requirements of the fugitive emissions monitoring program.

Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources, 81 Fed. Reg. 35824, 35856 (June 3, 2016). The italicized sentence above refers to an EDF study designed to create the illusion that low producing wells were really "super-emitters." This study was then characterized as the basis for removing the low producing well exclusion for the Subpart OOOOa fugitive emissions program. Contrary to this study, a recent Department of Energy-funded, peer-reviewed study conducted by researchers from Pennsylvania State University found that methane leakage rates from natural gas wells and other infrastructure in the Northeast Marcellus Shale are roughly 0.4% of production. This leakage rate is well below the threshold for natural gas to maintain its climate benefits over other traditional fuel alternatives. This study may be publicly accessed at the following internet link https://www.atmos-chem-phys.net/17/13941/2017/acp-17-13941-2017.pdf. This new information contradicts the EDF study and is sufficient basis for the EPA to stay the compliance deadline for LDAR requirements as they pertain to low production wells.

It is important to understand that the EDF study used data from a number of different studies to support its theory. All of the underlying studies generated their data by driving vehicles with samplers downwind of production sites, hunting for methane plumes. None of them used samples taken on the production site. This creates two issues. First, it measures everything emitted at the site – fugitive emissions and permitted vents. Second, the data was collected over minutes – maybe over an hour – but not over an entire day. The data in the studies is presented as if they were daily emissions but the studies merely scale-up hourly estimates. Consequently, an emission that might occur for several hours, but not the full day, would be overstated.

Before turning further to describe the submitted study, it is useful to look at the same data using a direct graph of emissions.



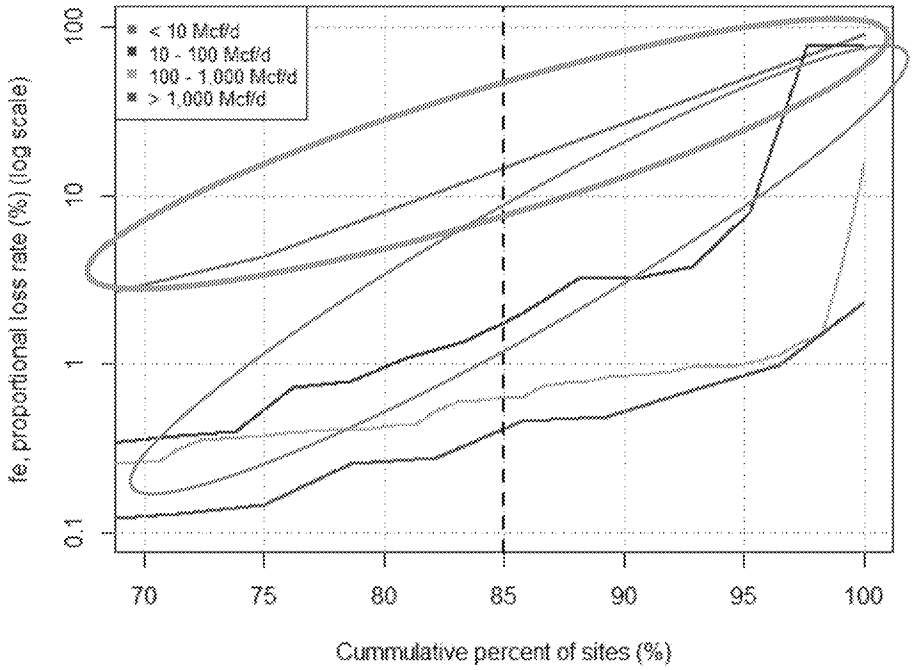
In this graph, marginal wells are those with production volumes of 90 mcfd or less.

Graphing the data this way is consistent with information from other studies showing that a small portion of wells have an emission profile for some reason with high emissions and most wells have really low emissions. Importantly, it also clearly shows that marginal wells – low producing wells in the context of the regulation – have far smaller emissions. But, since this graph is using the same data as the study, it could also be overstating emissions because of scaling short term emissions to a daily amount.[2]

With this background, turning to the presentation of the same material in the study demonstrates how it was manipulated.

Below is the graphic used to present the data. It would suggest that the worst emitting operations – the "super-emitters" – are the smallest wells (the orange line and the blue line, circled in green). Having directly plotted this data, the obvious issue is how such a result can occur.

[2] For example, a recent National Oceanic & Atmospheric Administration study, *Improved Mechanistic Understanding of Natural Gas Methane Emissions from Spatially Resolved Aircraft Measurements*, raised issues regarding the time of day when data is collected because of normal operational and maintenance activities that occur during morning and midday hours.



It is a busy and confusing graph – it is intended to be. The study uses data analysis tricks to create the appearance that marginal wells are "super-emitters."

First, it shows emissions as a percentage of production rather than actual emissions. Thus, 1 mcf emitted out of 10 mcf produced is 10%, but 50 mcf emitted out of 1000 mcf produced is 5%. As a result, it skews the perception of the data to imply that low producing wells are large emitters when they are not.

Second, its production volumes are sales volumes, not the amount extracted from the wellhead. Consequently, a "proportional loss rate" of 50% would be the calculated loss divided by the volume sold. If the percentage of loss were calculated based on extracted volumes, the 50% "proportional loss rate" would drop to 33% because the loss would be added to the sales volume to obtain the extracted volume.

Third, it only shows data from the 70th percentile of information. This excludes all of the virtually zero emissions that dominate the data.

Fourth, it uses a logarithmic scale to present the data. One of the reasons to use logarithmic scales is to flatten curves to make them look more like straight lines.

These observations can be made without conducting an intense investigation of the study. They are obviously intended to contort data to create a specific result. Yet, with all the investigative power at the EPA, with all of the research the EPA has conducted, the EPA took this contrived study at face value to make its determination to remove the low producing well exclusion in the Subpart OOOOa regulations.

In addition to this mischaracterization of the emissions nature of low producing wells, the EPA never did a cost effectiveness analysis of the fugitive emissions program as it applies to these facilities. Not surprisingly, the impact is significantly different between small and large wells. For the past several years, the EDF has scammed the country and many regulators with an analysis that it developed showing that a variety of methane controls are cost effective. The EDF likes to state that these controls only cost a few cents.

The problem is that the EDF's analysis is flawed and, when the average low producing well produces 22 mcf per day, a few cents per mcf means a lot. The EDF initially contracted with the ICF International ("ICF") to develop its economic analysis of methane emissions controls. In 2016, ONE Future Inc., contracted with the ICF to revisit its prior work using more realistic assumptions.[3] One key assumption – an assumption that is also problematic with the EPA's economic analysis for Subparts OOOO and OOOOa – is the value of methane used in the analyses. The EDF and the EPA use a value of $4.00/mcf. This is not a realistic value. The ONE Future analysis used $3.00/mcf, which is close to the current national wellhead price for natural gas but still conservative (low). Equally important, it reflected that a producer does not receive this amount due to royalties and fees that are about 25% of the wellhead price and therefore reduces the net to the producer to about $2.25/mcf. However, even the ONE Future/ICF report does not attempt to distinguish the cost effectiveness of controls based on size of operation.

However, it can be done. The ONE Future/ICF study developed information on the cost of a fugitive emissions leak detection and repair (LDAR that approximates the Subpart OOOOa biannual testing program. It concluded that the annual cost for the program is $3,436.[4]

There are little data on the emissions from low producing wells. However, in the EPA's April 2012 Technical Support Document for its NSPS,[5] it created a model plant well pad for one well that estimates methane emissions at 0.330 tons/year.[6] This translates to 16 mcf/year.

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[3] *Economic Analysis of Methane Emission Reduction Potential from Natural Gas Systems*, ICF International, May 2016.

[4] As noted and set forth in their own cost analyses below, the Independent Producers submit that this agency estimate is low.

[5] *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Background Supplemental Technical Support Document for the Final New Source Performance Standards*, EPA, April 2012.

[6] Ibid, Appendix C.

The ICF analysis uses an estimate that 50% of these emissions would be reduced by the LDAR program. Using the more realistic product prices, this recovery adds about $17.50 to the income of the well and reduces the net cost to about $3,418/year. It is noteworthy to point out that even this small recovery may overstate the amount. Field experience with state fugitive emissions programs indicates that after the first examination of a facility and the initiation of operation and maintenance programs on equipment, subsequent LDAR reviews find far fewer leaks to repair.

The larger question is what impact does this have on a low producing well. Using the ICF assumptions, the average low producing well (22 mcf per day) would receive daily income of $49.50 ($18,000 per year).

It is difficult to determine operating costs but the Energy Information Administration ("EIA") released a report in March 2016, *Trends in U.S. Oil and Natural Gas Upstream Costs*, which assessed a wide range of costs and looked at several production areas. One of its evaluations addressed operating costs in the Marcellus play – the world-scale natural gas play in the northeastern states. The report estimated that Marcellus operating costs range from $12.36/BOE to $29.60/BOE. Using the standard 1 BOE = 6 mcf conversion, it produces operating costs ranging from $2.06/mcf to $4.93/mcf. Applying these costs to the average low producing well results in a daily cost range of $45.32 to $108.46.

Consequently, the average low producing well would have to manage its finances in a range from a daily income of $4.18 to a loss of $58.95. In this difficult financial situation, the application of the EPA LDAR program is a more significant factor than EPA has presumed in its analysis. The daily cost of its program would be $9.36 – after taking into account methane recovery. For a low producing well, this small change would drive the well into a net loss ranging from about $5.00/day to $68.00/day.

Clearly, there are many factors that come into play in this analysis – price of natural gas, cost of the LDAR program, operating costs. The fundamental point is that an LDAR program that *may* be justified for large producing wells will have a very different impact on small ones. The EPA should develop a methodology that reflects these differences and it has not.

Additionally, in the context of the EPA's immediate need to consider staying the fugitive emissions requirements, the impact of the Subpart OOOOa NSPS on modifications is significant. The CAA defines "modification" in the context of Section 111 as:

> …any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.

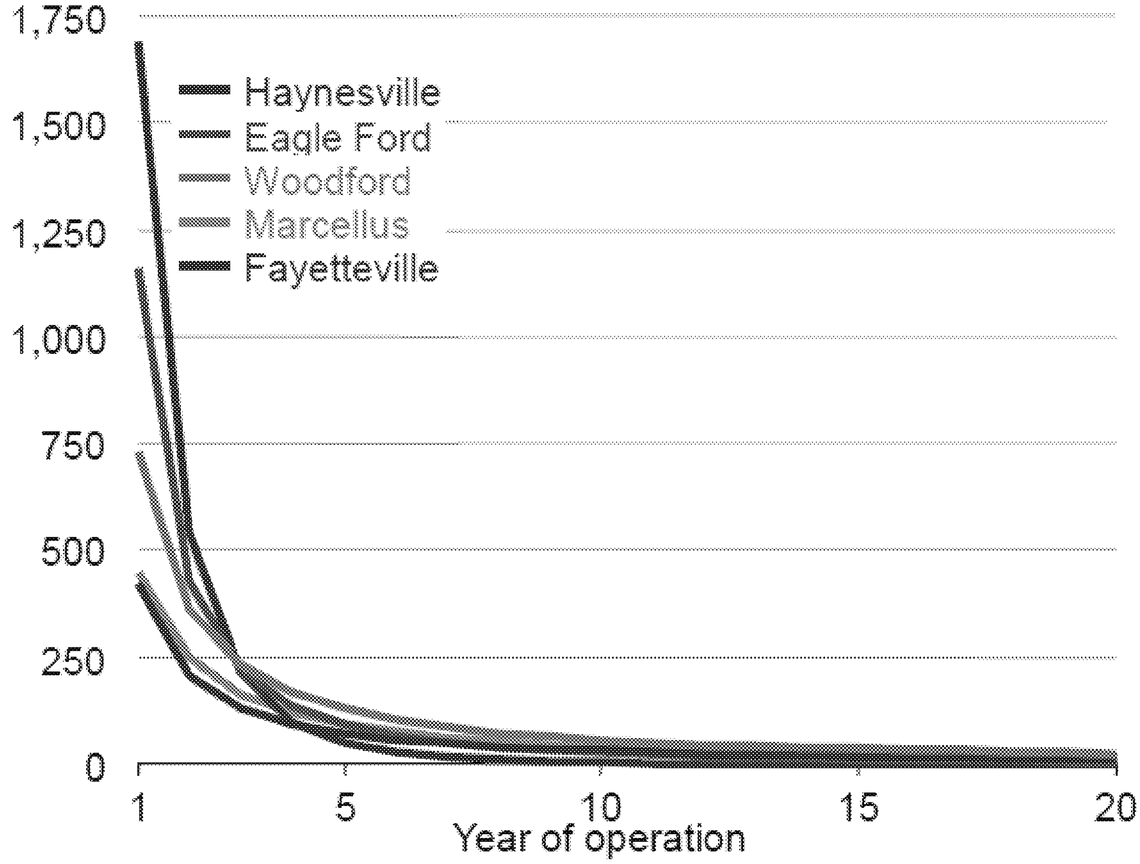
42 U.S.C.A. § 7411(a)(4) This is not the criteria that the EPA used in defining "modification" in Subpart OOOOa. In Subpart OOOOa, the EPA states:

> A "modification" to a well site occurs when:
>
> (i) A new well is drilled at an existing well site;
>
> (ii) A well at an existing well site is hydraulically fractured; or
>
> (iii) A well at an existing well site is hydraulically refractured.

81 Fed. Reg. 35900 (June 3, 2016). The EPA justifies its use of this definition in the Federal Register Notice on Subpart OOOOa by stating:

> The EPA believes the addition of a new well or the hydraulically fracturing or refracturing of an existing well will increase emissions from the well site for the following reasons. These events are followed by production from these wells which generate additional emissions at the well sites. Some of these additional emissions will pass through leaking fugitive emission components at the well sites (in addition to the emissions already leaking from those components). Further, it is not uncommon that an increase in production would require additional equipment and, therefore, additional fugitive emission components at the well sites. We also believe that defining "modification" to include these two events, rather than requiring complex case-by-case analysis to determine whether there is emission increase in each event, will ease implementation burden for owners and operators. For the reasons stated above, EPA is finalizing the definition of "modification" of a well site, as proposed.

81 Fed. Reg. 35881 (June 3, 2016). This rationale is generally incorrect because emissions do not arise from the fracturing of a well but from production and the equipment to manage these emissions would be in place at the time of the fracturing. But, it is specifically incorrect with regard to the refracturing of wells. Refracturing of a well is a normal operational practice to sustain production from existing wells. The EPA has never seemed to grasp the concept that oil and natural gas wells decline over time. The following graph shows a typical decline curve for hydraulically fractured wells.



As a well produces, its rate declines over time. The equipment that manages air emissions at a facility must be designed for its initial production. A normal practice to extend the life of a well is a workover or secondary recovery project that recovers some portion of the well's production. For hydraulically fractured wells, refracturing is a method that allows additional production from the well. Importantly, refracturing will not bring the well production back to its initial volume or pressure. Therefore, refracturing will not increase emissions at the well site because the emissions management facilities will operate below their initial design volumes.

In using the Subpart OOOOa modification definition, the EPA violates the direct definition of modification in Section 111 of the CAA. And, it is creating consequences.

Because the fugitive emissions requirements are a perpetual cost that attaches to each well that becomes subject to Subpart OOOOa, declining wells that need to be refractured to maintain their production are not being addressed. As a result, American oil and natural gas that could be produced, will not be produced. The loss of this production should concern the EPA and it should act to forestall these adverse consequences.

In addition to these adverse consequences, there are unforeseen consequences of Subpart OOOOa. In West Virginia, and other states, facilities that were, prior to Subpart OOOOa, not subject to minor source permitting are finding themselves subject to state minor source permitting for the first time. Not only does that minor source permitting require them to expend limited resources on permitting fees ($1000 to $3000), but it exposes them to additional liability. These additional "compliance costs" were not contemplated or accounted for in the EPA's cost/benefit analysis of the LDAR requirements.

The Independent Producers petitioned the EPA to reconsider its decision regarding the inclusion of low producing wells in Subpart OOOOa and to address the incorrect definition of modification. As a part of the EPA's actions to stay the immediate implementation of the fugitive emissions requirements of Subpart OOOOa, the EPA should defer application of the fugitive emissions program on low producing wells and on refracturing of existing wells until it completes action on the pending petition for reconsideration.

C. The EPA Must Re-evaluate the Costs of Compliance with More Representative Gas Prices and Assumptions.

An Independent Operators[7] provided the following information regarding cost associated with the regulations. The Independent Operator administers approximately 1,000 wells with an average of 9 barrels of oil per day per well. As a result of the numerous regulations passed during the previous Administrations, the Independent Operator was forced to double its regulatory personnel and to contract an environmental company to help comply with the regulations. The Subpart OOOOa regulations are just another example of severe government overreach that will further drive costs up even with little benefit. The Independent Operator estimated it spends an average of $1,363,000 per year to meet current state and federal regulations (about 4.3% of the total operating budget). If Subpart OOOOa regulations are implemented, the Independent Operator could easily spend $2,500,000 to comply at all battery and well sites, suffering an increase in its operating budget of almost 8% in the first year and an increase of 3.1% in subsequent years. Considering the majority of the wells have a gas-oil ratio of 200 or less, this would mean that the Independent Operator would have to spend the equivalent of $4.76/mcf of gas in the first year to modify batteries and equipment, and $1.90/mcf of gas in following years to repair and constantly upgrade equipment. With existing gas contracts, gas production going forward would be uneconomical and potentially devastating. Currently, gas production due to processing fees and historically low prices is marginal, at best, with average gross prices at $3.00 or less, and net prices at $1.50 or less.

[7] Individual members of the Independent Producers who wish to remain anonymous are referred to as "Independent Operator."

Most importantly, the cost of eliminating "fugitive" emissions is astronomically high. The Independent Operator mentioned above estimated reduction in emissions company-wide amounts to a decrease of about 14.4 mcf per day. In other words, the Independent Operator would spend $4.76/mcf of fugitive gas to stop "potential" emissions, while the gas is worth less than $3.00/mcf in the market! Then, the Independent Operator would spend $1.90/mcf of fugitive gas on an ongoing basis to stop potential emissions. This makes no economic sense but is very real for many independent operators.

The EPA states that much of the methane and volatile organic compounds ("VOCs") that are captured as a result of this regulation will be sold into the natural gas market. The EPA is expecting owners and operators to use the gas sales to offset compliance costs.

Most of the gas that is not being sold today costs too much for owners and operators to collect, process, transport, and sell into the natural gas market. Management teams at energy companies have fiduciary responsibility to use owners' and investors' capital in the most efficient way possible. If projects to collect, process, and sell gas were economically attractive, companies would have already made the investment.

Many of the wells are drilled and produced in the Illinois Basin have a gas to oil ratio that is greater than the minimum threshold, but far below the quantity to justify a profitable project. The associated gas would need to be purified to make it pipeline quality, which is a significant investment for the small volume of produced gas. This particular company estimate that the construction of a gas processing facility could cost $1 million to $2.5 million, depending on gas quantity and quality.

Most operators in the Illinois Basin do not have gas gathering pipelines installed to enable collection and processing of the gas. Gas gathering lines could exceed $500,000 per field to procure right of way, install the pipeline network, and install measurement instrumentation. There are a few interstate pipelines crossing the Illinois Basin, but in addition to the cost of building the gathering lines, the required tie-in and associated measurement equipment on an interstate pipeline may cost an additional $250,000 to $500,000.

The Independent Operator evaluated several natural gas projects in the Illinois Basin. In every case, the projects were uneconomic because nitrogen is a common contaminant in the separated gas; and it is very expensive to remove. These projects do not produce enough gas to justify cryogenic nitrogen removal, which is the lowest cost option. The next best alternative is a pressure swing absorption ("PSA") system or equivalent filtering method. With the produced gas, this results in an additional processing cost of approximately $1.00/mcf. According to the EIA, the Henry Hub contract price for natural gas in June 2017 is approximately $3.30/mcf. At the current gas price, any project that requires nitrogen removal will lose money for the investor.

The Independent Operator also performed Monte Carlo simulations around expected gas production, gas quality, compliance cost, operating cost, and product pricing. The outcome of these simulations shows that none of the projects were profitable (positive Net Present Value ("NPV")) and any management team would reject the investment opportunity. Every well that Independent Operator may drill would only have additional compliance costs added to operation and no economic benefit would be realized from the typical well fields that they produce.

Many of the oil producers in the Illinois Basin do not process and sell gas that is associated with oil production because the processing costs are high relative to the volume of associated gas and because interstate pipelines are not readily accessible to the operators. Figure 1 (source: United States Geological Survey ("USGS")) shows a map of the Illinois Basin and Figure 2 (source: EIA) shows interstate and intrastate natural gas pipelines in Indiana and Illinois.

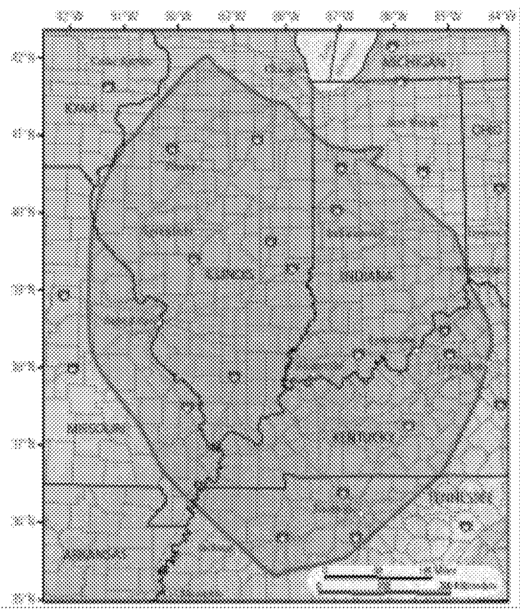


Figure 1. Illinois Basin

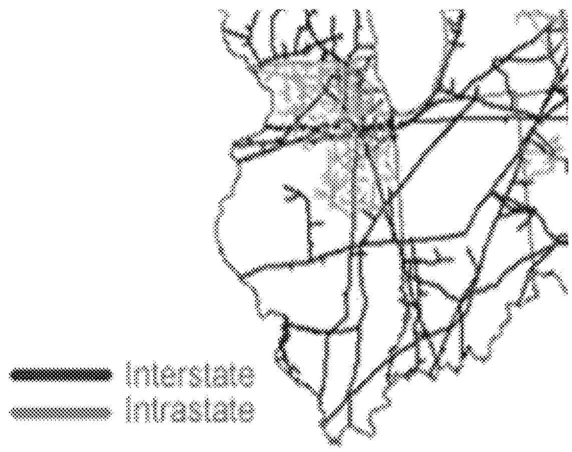


Figure 2. Illinois and Indiana Natural Gas

Most of the oil wells do not have reasonable access to interstate or intrastate pipelines to transport produced gas to market. The cost to purchase right of way, install gas pipelines, tie into transportation pipelines, and install custody transfer instrumentation exceeds the economic benefit of selling the gas.

This particular Independent Operator's interpretation of the EPA's economics is that the EPA assumes installing a gas gathering pipeline is relatively low cost and that a right of way is easy to procure. Instead, the Independent Operator's experience is that pipelines are expensive to install and maintain and acquiring a right of way ranges from easy to difficult.

Some land owners are accommodating while other land owners have no interest in having any type of pipeline on their property. The ability to secure a right of way has significantly impacted projects, ranging from additional cost to project cancelation. The effort and cost to secure rights of way should not be underestimated for any type of pipeline project.

SPECIFIC ISSUES RAISED IN THE NODA

Throughout the NODA, the EPA asks specific questions regarding the technological, resource, and economic challenges with implementing certain aspects of Subpart OOOOa, including the fugitive emissions requirements, well site pneumatic standards, and the requirements for certification of closed vent systems by a professional engineer. The Independent Producers pulled from the NODA the specific questions and solicited their members for specific input. The Independent Producers tried to provide the necessary background information for the questions sought by the EPA. The questions presented to the members are reproduced below and the responses are summarized below the corresponding question.

1. **Should a phase-in period be implemented to allow a scale-up of the number of qualified professional engineers (to meet the rule's certification requirement by such professionals of (1) the closed vent systems routing emissions from various equipment and (2) technical infeasibility of routing emissions from a well site pneumatic pump to an existing control device or process onsite).**

- An Independent Operator suggests a phase-in period to provide the EPA the time necessary to address issues arising from ambiguities or internal contradictions that are latent within the drafting of the regulation. The regulation should be modified to encourage and permit additional Professional Engineers to practice in this area or eliminate the requirement for a Professional Engineer review.

  The EPA provides the following definition of a Qualified Professional Engineer:

  > *Qualified Professional Engineer* means an individual who is licensed by a state as a Professional Engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge and experience to make the specific technical certifications required under this subpart. Professional engineers having these certifications must be currently licensed in at least one state in which the certifying official is located.

81 Fed. Reg. 35935 (June 3, 2016). A search of qualified Professional Engineers was conducted throughout the Illinois Basin. While this was not an exhaustive search, only one engineering firm has been identified that meets the requirements set forth by the EPA in Subpart OOOOa. The engineering firm does not primarily perform work in the Oil Exploration and Development business segment, but rather specializes in industry plant design and modifications. The engineering firm only meets the EPA's criteria because it performs flare system design for chemical plants and oil refineries, and because it has engineers licensed in one of the states in the Illinois Basin.

While the identified engineering firm may be available for some of the operators in the Illinois Basin, not all operators are permitted to work with the identified engineering firm. Per the EPA's definition, the Professional Engineer must be licensed in at least one state in which the certifying official is located. Several of the operators do not have operations in the state where the engineering firm is located, which eliminates this option for compliance.

Working with a large engineering firm to meet the EPA's compliance requirement is much more expensive than working with small engineering firms or independent Professional Engineers. Larger engineering firms have sufficient staffing and capabilities (*i.e.*, computer modeling software) to validate vent system design or technical infeasibility. Most of the smaller engineering firms or independent Professional Engineers are not able to afford the staffing or tools to perform the work that is required by the EPA.

The additional staffing and capabilities come at a cost to the operator. For example, a vent system conceptual design cost could exceed $10,000, with the detailed design provided by the engineering firm exceeding $100,000. The Professional Engineer certification for each installation may cost an additional $3,000. The cost to install a vent system could be $30,000 to $60,000, based on the emission rate (*i.e.*, pipe and certified combustor sizing). With the typical cost of a new tank facility in the Illinois Basin being $40,000 to $50,000; the cost to meet the EPA's regulation will total more than the initial cost to construct the tank facility. Most small operators are not able to incur this type of additional cost for low producing wells. A low producing well might have the potential to emit 10 tons per year during initial production, but in less than a year is emitting less than 5 tons per year due to production decline. This regulation is excessively burdensome for small operators with a large inventory of low producing wells.

During the search for qualified Professional Engineers, several independent Professional Engineers and small engineering companies were interviewed. Of the few Professional Engineers that met the EPA's narrow definition, even fewer were willing to sign the EPA's liability statement. The EPA requires the Professional Engineer to execute and date the following statement for each technical infeasibility or each vent system design:

> *I certify that the assessment of technical infeasibility was prepared under my direction or supervision. I further certify that the assessment was conducted and this report was prepared pursuant to the requirements of §60.5393a(b)(5)(iii). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete. I am aware that there are penalties for knowingly submitting false information.*
>
> *I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted and this report was prepared pursuant to the requirements of subpart OOOOa of 40 CFR part 60. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete. I am aware that there are penalties for knowingly submitting false information.*

This search found that many Professional Engineers are not willing to accept the exposure to the EPA over a vent system design. Many of the Professional Engineers did not believe that the professional exposure was worth the risk of the EPA being involved with their practice. Several of the Professional Engineers are willing to forego the additional revenue in exchange for the reduced risk of not being open to an EPA audit.

Approximately 18 months after Subpart OOOOa was published to the Federal Register, only one qualified engineering firm could be identified within the three states that Illinois Basin crude oil is produced. A sufficient number of qualified Professional Engineers are not available for all of the operators throughout the three states. Additional time will not significantly improve the number of Professional Engineers to perform this work in the Illinois Basin.

- Range Resources indicated a phased-in period is recommended to allow for adequate time for a qualified Professional Engineer to become familiar with the closed-vent system ("CVS") design that is being, or will be used to meet regulatory requirements. Technical feasibility of controlling emissions from a pneumatic pump is a function of its location, relative to a process or the control device. Pneumatic pumps that are near processes or control devices are more likely able to be controlled than units that are situated at greater distances. Alternatively, units that are located too far from available control options will likely not be technically feasible to control. To comply with the emission reduction requirements, site equipment layouts will need to be revised to strategically locate pneumatic pumps.

- Another Independent Operator suggests that these portions of the regulation should be considerably modified or eliminated from the regulation because they require operators to utilize resources that are not widely available. Qualified Professional Engineers are generally not available due to many of the requirements set forth by the EPA in the regulation. The few resources that are available are unnecessarily expensive for many operators to incur the additional compliance cost and still have a profitable project.

- LINN Energy ("LINN") indicated the primary problem is that a lengthy time period is needed in order to get the adequate design approved. A cookie cutter design does not necessarily work and it often requires more time than the rule allows after the site is operational in order to properly design the CVS. Often a company will not even know if the design will work until the site is in routine operation. If the site is a horizontal drill with fracturing, it may take even longer to ensure that the CVS is adequately designed. This has been an on-going issue for operators since the rule has been implemented.

- Comments submitted by Tom C. Roberts, President, National Society of Professional Engineers ("NSPE") points out "according to the National Council of Examiners for Engineering and Surveying, there were over 400,000 resident PE licenses and 400,000 nonresident licenses issued (a single individual can possess both) in 2016." We agree that Professional Engineers provide a great service to American industry and that they have unique qualifications, expertise, and the legal and ethical capability to ensure public health, safety, and welfare in their designs. While our industry agrees that a great number of Professional Engineers are practicing in many engineering disciplines throughout the United States, very few of the Professional Engineers meet the EPA's qualifications to provide certifications. Many of our companies employ Professional Engineers, but the Professional Engineer is unable to provide a service to their employer as a result of the narrow definition that the EPA provided for a Qualified Professional Engineer.

2. How long a phase-in period is necessary in order to achieve the scaleup of qualified professional engineers?

- Subpart OOOOa was published to the Federal Register approximately 18 months ago. One Independent Operator's experience over that time period, is that none of the Professional Engineers that have been interviewed have worked towards meeting the EPA's requirements to approve a vent system design or technical infeasibility. The Independent Operator believes additional time should be permitted to provide the EPA an opportunity to consider how to best change the regulation to meet operators needs and the EPA's desire to ensure that vent systems are correctly implemented.

If the EPA desires to have Professional Engineers review and approve vent system designs or technical infeasibility, the EPA will need to find additional methods to incentivize engineers to meet the EPA's requirements. Currently none of the engineers that have been interviewed have indicated an interest to become qualified to meet EPA's requirements.

Two years would be a minimum, but five years would be a more realistic time horizon for EPA to evaluate options, complete the public comment period, issue the final ruling, and then provide a period for industry to prepare to implement the revised regulation. The 60 days that EPA originally provided to begin compliance was wholly inadequate.

- Another Independent Operator indicated that the certification is not currently a common industry practice, so probably two to four year time period would be more reasonable for this to become a common set of engineering calculations Professional Engineers in the petroleum industry routinely make.

- Range Resources indicated a minimum of 12 months is recommended – but 24 months would be preferred – for existing in-house staff to obtain professional credentials, or independent, third party Professional Engineers to comprehend design changes and operations of site specific designs and operations. Professional Engineer Examinations require months of preparation and are only offered bi-annually.

  Contract engineers are required to adjust to changing production parameters as well pad designs are continuously evolving in response to equipment changes and different production techniques (*e.g.*, longer laterals). Standard designs are generally modified each year as data becomes more available for mechanical, electrical, and instrumental modifications/improvements.

3. What challenges are sources experiencing difficulty in carrying out requirements of:

(i) securing the necessary equipment and/or personnel to conduct the required monitoring survey of fugitive emissions; and

- One Independent Producer is experiencing a number of challenges in being able to comply with Subpart OOOOa fugitive emission survey requirements. The challenges will be discussed individually below:

  a) Equipment Purchase Cost: Performing fugitive emission surveys as required by the EPA by purchasing equipment is not cost effective.

1) The cost to purchase equipment (*i.e.*, forward looking infrared ("FLIR") camera) is approximately $100,000, plus training and insurance cost. Most small operators in the Illinois Basin cannot justify the cost to purchase equipment and provide training for field staff.

2) Many of the operators initially only have a small number of wells and tank facilities that meet the requirement for the LDAR program. The cost of equipment cannot be spread over a large number of wells and tank facilities.

3) Most operators in the United States, not just the Illinois Basin, do not have available cash to purchase monitoring equipment and pay for training. The oil exploration and production business segment is entering into the fourth year of the most severe industry downturn since the 1980's. Most operators are struggling to provide sufficient cash to operate their business.

b) Contract Services for Compliance: Contracting with a third-party company to complete LDAR survey requirements.

1) Several companies have been interviewed to provide LDAR services to the Illinois Basin. No company in the Illinois Basin has been willing or able to purchase equipment to perform the inspection services due to the high cost of equipment and risk of not being able to cover the personnel, equipment, and training costs. All contract resources are located outside of the Illinois Basin.

2) No companies are currently located in the Illinois Basin, which results in additional travel cost. Travel and Per Diem cost could add thousands of dollars in compliance cost with no additional benefit.

3) If compliance equipment is rented without a trained operator (*i.e.*, rent a FLIR camera and train company employees to operate the camera), equipment is available for approximately $1,000 per week. While this might appear to be the most cost effective option, it still requires an employee to be sent to training at a costs of $3,000 to $5000. The operator is also liable for damage to the equipment, potentially purchasing the $100,000 camera if it is broken. This option also comes at an opportunity cost from the employee that is directed to complete compliance activities instead of other duties that provide other benefits to the operator.

4) Contract inspection services is an option that is available to operators. Contract services have been quoted at $350/hour, plus Per Diem with door to door service (*i.e.*, from the minute that the employee leaves their office until the minute that they

return to the office the operator is charged). It is estimated that two to four wells could be inspected per day in the Illinois Basin. At a cost of $2,800, plus a daily Per Diem, this will add $800 to $1,600 in operating cost to each affected facility for every inspection performed. This cost is doubled because wells and tank facilities are required to be inspected every six months.

c) Survey Frequency: The EPA requires operators to inspect wells and tank facilities within 60 days after startup or modification and every six months after the initial inspection. With the required inspection dates spread throughout the year, performing well site and tank facility inspections will be expensive because the operator will eventually have a continual requirement to inspect well sites and tank facilities. The way that the inspections are currently established, operators are not able to cost effectively contract an inspection company to perform LDAR inspections on all facilities twice per year. The EPA may consider changing the inspection requirement to have all well sites and tank facilities initially inspected using a low-tech method, such as soap bubbles, and then inspect the location within six months of startup using Optical Gas Imaging ("OGI"). Making this change will enable operators to have all well sites and tank facilities inspected at the same time by a qualified contractor.

   The EPA also requires an inspection after each fugitive gas emission point has been repaired. This requirement will increase the cost of inspections because the inspection company will either have to spend time waiting for a leak to be repaired or traveling back to the location after a repair has been completed (which could be up to 30 days later). In either case, the subsequent inspection will result in considerable additional cost to the operator.

   Updating the inspection requirements will enable existing inspection companies a greater opportunity to perform inspections for other companies. As the regulation is currently structured, an operator may have an inspection company contracted to perform all of their inspections. Due to the inspection requirements covering several months, the inspection company may be unwilling or unable to accept new clients due the inspection requirements of existing contracts.

d) The documentation required during the monitoring survey of fugitive emissions will be the most time consuming and expensive part of the LDAR program. The EPA recently released the annual reporting template. In the template the EPA requires general information (19 fields) to be completed for each well or tank facility, 25 additional fields to be completed for LDAR monitoring at each affected tank facility, and 27 fields to be completed for LDAR monitoring each affected well facility. The data that are required for the annual reports do not include all of the other data that the EPA requires operators to collect and store for five years during each fugitive emission survey. The documentation collection (not just for the LDAR section) is the most burdensome part of the entire regulation. Reducing the documentation that needs to be collected and stored should be included in the review.

The following information is required for each fugitive emission survey. Similar volumes of documentation are required for other sections of the rule.

i. Date of survey

ii. Beginning time

iii. End time

iv. Name of operator(s) performing the survey

v. Training and experience of OGI operator

vi. Ambient temperature

vii. Sky condition

viii. Maximum wind speed at the time of the survey

ix. Monitoring instrument used (manufacturer and model number)

x. Deviations from the monitoring plan, or a statement that there were no deviations from the monitoring plan

xi. Number of components where fugitive emissions were detected

xii. Type of components where fugitive emissions were detected

xiii. Number of fugitive emission components that were not repaired as required in Section 60.5397a(h) (routine monitoring of fugitive emission components)

xiv. Type of fugitive emission components that were not repaired as required in Section 60.5397a(h) (routine monitoring of fugitive emission components)

xv. Number of difficult to monitor fugitive emission components monitored

xvi. Type of difficult to monitor fugitive emission components monitored

xvii. Number of unsafe to monitor fugitive emission components monitored

xviii. Type of unsafe to monitor fugitive emission components monitored

xix. Date of successful repair of fugitive emission component

xx. Number of fugitive emission components placed on delay of repair

xxi. Type of fugitive emission component placed on delay of repair

xxii. Explanation for each fugitive emission component placed on delay of repair

xxiii. Type of instrument used to resurvey repaired fugitive emission component that could not be repaired during the initial fugitive emissions findings

This list does not yield a benefit for the operator collecting the data or the EPA in reviewing the data. We believe that most of the data that are required can be eliminated and not impact the results of the fugitive gas emission survey.

- Devon Energy ("Devon") suggests a revision to annual LDAR instead of semi-annual for well sites and compressor stations. In general, Devon has not had issues with securing personnel, equipment, etc. for LDAR as it is done in-house but is extremely expensive. Devon would revise the repair obligations to repair leakers within two years or *at next scheduled shutdown*.

- Range Resources also commented on the survey equipment being expensive: a single OG1 camera typically costs $85,000 to $95,000 to purchase and requires annual maintenance that costs approximately $3,000. Experienced corporate staff that have performed initial surveys often have additional ongoing environmental responsibilities so new staff will be required to conduct periodic surveys.

- Another Independent Operator indicated acquiring two (2) additional new OGI cameras took more time than it had anticipated. The Independent Operator anticipated a one-month delivery delay, but the OGI cameras were not received until two months after ordering.

- Internally EnerVest compared cost/benefits of undertaking the survey provisions in-house versus certified consultant LDAR surveyor. Although initially the person would most likely not be needed full time as drilling is slow, the company will still be looking at approximately $100,000 to cover salary, truck, gas, medical, etc. The additional specific equipment and training would include:

    - FLIR camera cost: $97,000, plus extra battery ($165), software, etc.

    - Certification cost: 3-day course $2,000, plus hotel and meals

- Suggested general maintenance (mainly lens cleaning): yearly $1,200
- Suggested to trade in after 5 to 7 years, get credit for older model

In terms of hiring someone, EnerVest estimated an initial $750 per facility, plus $125 hourly charge for re-survey, plus hotel and mileage costs. There are also issues associated with the availability of a consulting LDAR surveyor: When a survey is cancelled due to inclement weather or other uncontrollable situations, the consultant may not have time to re-survey within the regulation re-survey guidelines. This can cause non-compliance for the company. For this reason, EnerVest has moved to obtain an in-house certified surveyor.

- Another Independent Operator had the following annual costs for complete LDAR on a per well basis:[8]
  - Rockies (WY and ND fields): $1,200/well
  - Permian (oil fields): $1,700/well
  - South Texas (gas field): $600/well
  - Some regions per well costs will vary due to LDAR analogs being in place at the state level such that the repair "infrastructure" is already in place.
- Based on its history implementing the LDAR surveys, another Independent Operator calculated a per facility cost of approximately $1,200 per well and that the cost does not go down appreciably if there are multiple wells per site.
- Another Independent Producer provided Statewide Area ("SWA") Wyoming LDAR cost based on 2016 annual LDAR survey and includes both in-house and contractor costs
  - Assesses overall costs per ton reduction and incremental costs per ton reduction at annual, semi-annual, and quarterly monitoring frequencies
  - *70 sites, including 169 wells and approximately 84,000 components*
  - 428 fugitive emissions counted during annual OGI

[8] This same Independent Operator identified another developing issue in the Permian field that Enardo tank valves are in very short supply. Operators order 50 for repairs/replacements but only get 5. So the larger point is that EPA should not just be concerned about challenges/limitations around LDAR camera, operators, repair contractors, etc. It is likely that, at least for the first few events, common types of leaks could result in bottlenecks in repair/replacement materials and thus in delays in the ability to conduct said repairs due to parts unavailability backlog.

- Associated counts of specific types of fugitive emission components based on equipment present on site

- Fugitive Emission Rates

  - Wyoming actual fugitive emission rate = 0.51%.

  - The EPA uses 1.18% fugitive emission rate from its OOOOa analysis

  - Colorado (CO) Regulation 7 and EPA erroneously reference fugitive emissions reductions in their technical documents

    - There are no semi-annual data from the CO Reg. 7 Study, yet the EPA referenced CO Regulation 7 document and used a 60% reduction rate.

    - The EPA utilized 80% reduction for quarterly monitoring, which is actually the reduction rate used in CO Regulation 7 for *monthly* monitoring.

    - This is important because EPA/CO underestimate annual monitoring benefit (51.7% vs. 40%) and overestimate reductions at semi-annual (57% vs. 60%) and quarterly (61% vs. 80%). This in turn, affects economic feasibility at various monitoring frequencies.

Monitoring Frequency	***Fugitive Emissions Monitoring (FEM) / LDAR Program Emissions Reduction***		
	CO Regulation 7	**EPA OOOOa**	**Wyoming Study**
Annually	40%	40%	51.7%
Semi-Annual	NA	60%	57.0%
Quarterly	60%	80%	61.0%
Monthly	80%	NA	NA

The following tables summarize the annual/semi-annual/quarterly Statewide Area LDAR costs:

STATEWIDE AREA COST BASIS - ANNUAL, SEMI-ANNUAL and QUARTERLY LDAR MONITORING[6]

IN HOUSE	Costs in $1000's	Cost Description
Camera	$30.10	One IR Camera: $92.25k + 13.39k 6° lens + $8.5k Extended Warranty = 114.14k ($2014)
		(Amortized @10% and 5 yr) = $30.1k / yr/camera. One-Time Cost, includes 100 mm lens and insurance.
Maintenance/yr.	$3.00	FLIR maintenance and shipping costs annually
FTE	$120.00	Cost for 1 FTE = $60/hr ($120 K/yr)
Training/employee	$1.00	$5,000/yr over 5 years = $1,000 annual cost
Vehicles	$10.50	Cost for vehicle/year
Mileage Cost	$0.70	$ per mile
Recordkeeping/Reporting	$90.00	Annual Monitoring = 0.75 FTE for Niobrara Program. Contractor = Internal costs for Recordkeeping/Reporting.
	$120.00	Semi-Annual Monitoring = 1.0 FTE
	$180.00	Quarterly Monitoring = 1.5 FTE
Parts/Labor Repair Costs (In House or Contractor)	$0.31	Average Repair Cost per Leak
Mileage Traveled	3,579	Annual Monitoring - Total miles based on average in-house technician mileage per site
	7,158	Semi- Annual Monitoring
	14,316	Quarterly Monitoring
CONTRACTOR		
OGI Contractor Costs for Niobrara	$0.90	$900/site for OGI

PAW LEAK DETECTION AND REPAIR (LDAR) COSTS ANALYSES - STATE WIDE AREA (SWA) - SUMMARY RESULTS

OVERALL COST ANALYSIS

FREQUENCY	TOTAL LEAKS	LEAK RATE	EMISSIONS CONTROLLED (Tons VOC)		TOTAL COSTS ($1,000's)		COST/TON VOC CONTROLLED ($1,000's)			
							Internal		Contractor	
			Based on Component Leaks Proportionate to Component Count	Based on Actual Leak Counts	Internal	Contractor	Based on Component Leaks Proportionate to Component Count	Based on Actual Leak Counts	Based on Component Leaks Proportionate to Component Count	Based on Actual Leak Counts
Annual	207	0.25%	62.95	58.33	$321.19	$217.08	$5.10	$5.51	$3.45	$3.72
Semi-Annual	184	0.22%	69.40	64.30	$346.66	$303.05	$4.99	$5.39	$4.37	$4.71
Quarterly	167	0.20%	74.27	68.82	$406.37	$483.75	$5.47	$5.90	$6.51	$7.03

INCREMENTAL COST ANALYSIS - SUMMARY RESULTS

APPLYING ADJUSTED LEAK RATES(%) TO INTERNAL and CONTRACTOR COST DATA

FREQUENCY	^ DELTA INTERNAL COST/TON VOC REDUCED	^ DELTA CONTRACTOR COST/TON VOC REDUCED
Baseline	NA	NA
Annual	$5.10	$3.45
Semi-Annual	$3.95	$13.32
Quarterly	$12.26	$37.10

Based on Leaks Proportional to Component Counts

FREQUENCY	^ DELTA INTERNAL COST/TON VOC REDUCED	^ DELTA CONTRACTOR COST/TON VOC REDUCED
Baseline	NA	NA
Annual	$5.51	$3.72
Semi-Annual	$4.26	$14.38
Quarterly	$13.23	$40.04

Based on Actual Leak Counts

^ Delta Internal/Contractor Cost Per Ton VOC Reduced = Reduced Contractor Total Cost/Tons VOC Reduced for given frequency of monitoring

PAW FEM/LDAR OVERALL COST ANALYSES - STATE WIDE AREA (SWA)					
NO. LEAKS REDUCED (Frequency)	REDUCED VOC EMISSIONS	REMAINING LEAKS	REMAINING EMISSIONS	TOTAL COSTS	COST/TON VOC REDUCED
				Contractor	Contractor
428 (Start)	NA	NA	112.7		
221 (Annual)	58.25	207	54.42	$217,084	$3,727
244 (Semi-Annual)	64.22	184	48.45	$303,052	$4,719
261 (Quarterly)	68.73	167	43.94	$483,745	$7,039

Incremental Emissions and Cost Analysis

- True measure of cost-effectiveness – assess costs and VOC reductions between FEM/LDAR monitoring frequencies (Incremental Analysis("IA"))

APPLYING ADJUSTED LEAK RATES (%) TO CONTRACTOR COST DATA				
	No. Leaks Reduced (based on increased Monitoring Frequency)	+TONS VOC REDUCED (based on increased Monitoring Frequency)	++REDUCED CONTRACTOR TOTAL COST (based on increased Monitoring Frequency)	+++INCREMENTAL CONTRACTOR COST/TON VOC REDUCED
BASELINE	0	NA	NA	NA
ANNUAL OGI	221	58.25	$217,084	$3,727
SEMI-ANNUAL OGI	23	5.97	$85,968	$14,397
QUARTERLY OGI	17	4.51	$180,693	$40,095

+ Tons VOC Reduced = Original Tons VOC for each Frequency - Tons VOC from next lesser frequency - e.g. - Semi-Annual = Original Tons Annual OGI - Original Tons Semi-Annual OGI

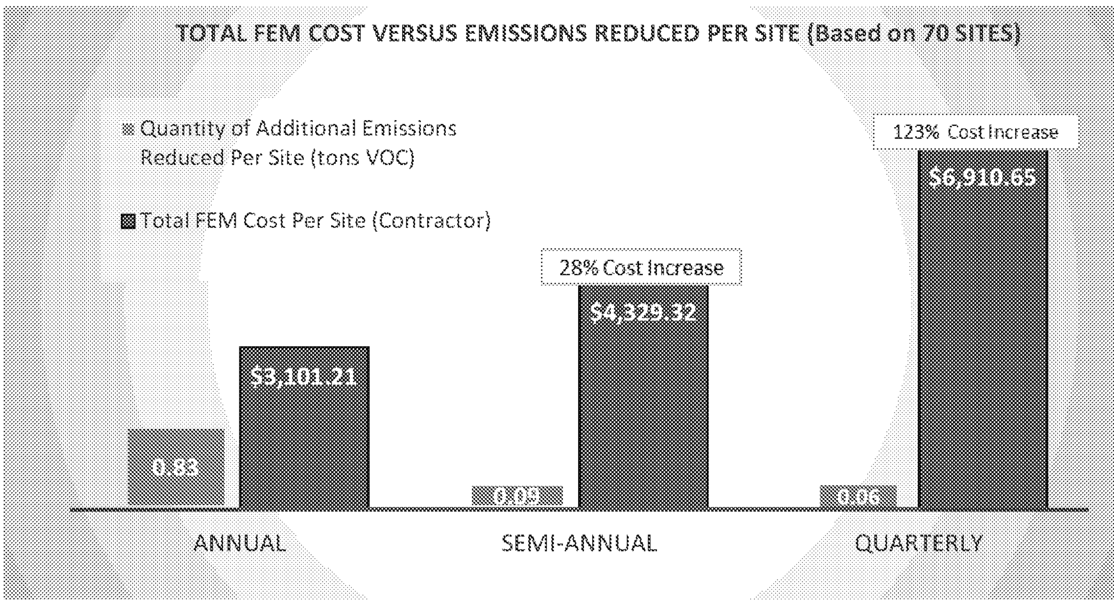
++ Baseline costs are assumed to be $0 as there was no LDAR Program in place.

+++ Reduced Contractor/Internal Total Cost = Cost of level of Monitoring - Cost of next lesser frequency of Monitoring - e.g. - Cost = Semi-Annual Original Cost -Annual Original Cost

Incremental Internal/Contractor Cost Per Ton VOC Reduced = Reduced Contractor Total Cost/Tons VOC Reduced for given frequency of monitoring

Leak and Emissions Reductions Versus Total FEM/LDAR Cost Per Site[7]

FREQUENCY OF MONITORING	LEAKS REDUCED PER SITE	Quantity of Additional Emissions Reduced Per Site (tons VOC)	Total FEM/LDAR Cost Per Site (Contractor)	COST INCREASE
ANNUAL	3.16	0.83	$3,101.21	NA
SEMI-ANNUAL	3.49	0.09	$4,329.32	28%
QUARTERLY	3.73	0.06	$6,910.65	123%



To summarize the data provided above:

- The data presented above is typical of a mid-sized operation in the SWA. *Costs associated with small operators can be much higher per site* than are represented with this data.

- *Fugitive emissions ARE NOT a significant source at upstream oil and gas facilities* (9% to 17%) from which to extract further emissions reductions through increased frequency of FEM/LDAR monitoring with the intent of reducing VOC's as an ozone precursor for the foreseeable future.

- Subpart OOOOa will be reconsidered in the near future and the incorrect basis of establishing semi-annual FEM/LDAR monitoring frequency will be challenged -

  - *The Petroleum Association of Wyoming ("PAW") recommends that the Wyoming Department of Environmental Quality ("WYDEQ") await results of Subpart OOOOa reconsideration process to utilize new data and analyses to inform FEM/LDAR presumptive best available control technology for SWA in Wyoming.*

- Using conservative component population greenhouse gas ("GHG") emissions factors, actual leak counts and control efficiencies from the WY Study results in the following when compared to EPA/CO Regulation 7 analyses:

- Wyoming-based data results in:

  - Annual = 221 leaks or 51.7% reduction (40% using EPA)

  - Semi-Annual = 23 leaks or additional 5.3% reduction (20% reduction using EPA)

  - Quarterly = 17 leaks or 4% further reduction (20% reduction using EPA)

- Incremental costs per ton VOC reduced between increasing monitoring frequencies are not cost-effective:

  - Annual to Semi-Annual = Only 23 leaks and 5.97 tons VOC reduced at a cost of $14,397/ ton

  - Semi-Annual to Quarterly = Only 17 leaks and 4.51 tons VOC reduced at a cost of $40,095/ton VOC

  - Annual to Quarterly Frequency = $25,445 /ton VOC reduced

- The EDF single-facility cost analysis using correct 60% control efficiency at quarterly monitoring = $8,271 /ton VOC controlled (does not include cost of leak repair)

- Incremental costs per site are very high with little benefit (Note: lower emission control effect and much higher cost/ton if using AP-42 emission factors versus actual GHG factors used)

- Annual = Cost of $3,101 per site, only 3 leaks and 0.83 tons VOC are reduced

- Semi-Annual = Cost of $4,329 per site, only an additional 0.33 leaks and 0.09 tons VOC are reduced

- Quarterly = Cost of $6,911 per site, only an additional 0.24 leaks and 0.06 tons VOC are reduced

- WYDEQ vs. PAW BACT Comparison – WYDEQ Meeting with PAW

  - Contains "WDEQ Analysis" – which only considered annualized capital costs and maintenance costs on camera

  - Added WYDEQ Analysis with operating costs – includes incremental costs for mileage and FLIR operation at each LDAR frequency. Basis of WYDEQ dropping reference to quarterly LDAR in pBACT for SWA.[9]

(ii) phase-in period until November 30, 2018,[10] to connect well site pneumatic pumps to an existing control or process onsite.

- From EnerVest's experience, it is typically infeasible to connect vapors from pump to controls due to pressure differential, distance to control, design of facility with truck and other workover traffic. One would need another pump to pump the vapors to the control. For sites that have no controls, it is infeasible to add a control for the pneumatic pump. EnerVest uses solar pumps

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[9] *See* WYDEQ vs PAW BACT Comparison Excel Spreadsheet (attached as Exs. A1, A2 and A3).

[10] November 30, 2016 is the date identified in the proposed notice but that date is an artifact of the original proposal "[t]herefore, we are finalizing the compliance period to begin on November 30, 2016 to allow sufficient time for these necessary tasks to be completed." 81 Fed. Reg. 35851 (June 3, 2016). Given the two-year stay proposal, this would presumably shift that date to November 30, 2018. The NODA in its estimated cost savings section gives a time frame of January 2018 to December 2019. Thus, the Independent Producers are presuming that the EPA's proposed two-year stay (or phase-in window) presumably shifts that date to November 30, 2018.

but its facilities have lots of sun. Tree areas of the country may not be able to use solar. This part of the rule should be eliminated.

- Range Resources is of the opinion that for operators with large numbers of well locations without necessary control devices, the two-year phase-in period is appropriate.

- LINN has not been using well site pneumatic pumps, but if it were to use them, all of them will be classified as technically infeasible because the difference in pressure inside of the closed vent system in comparison to what is coming out of the storage tanks will be too great to design a safe system.

- Another Independent Operator commented on the Alternative Means of Emission Limitation ("AMEL") Leak Repair Data – The EPA included leak costs in their cost analysis to justify semi-annual leak repair for NSPS Subpart OOOOa. The EPA assumed a 1.18% leak rate, equivalent to 3 leaks repaired for their 22 well site "Model Plant." The EPA derived a total cost of $597 for leak repair. We used an average cost of repair of $310/leak based on cost input from our operations staff.

- Another Independent Operator has calculated the following costs for a voluntary program that is not the mandatory Subpart OOOOa program.

	2014	2015	2016
# of Inspections (# of wells surveyed)	3071	5592	5618
Component Leaks per well surveyed	0.18	0.15	0.15
Leaking Component % (Total Leaking components observed/Total estimated components at site)*.	0.06%	0.06%	0.06%
SWN SMART LDAR Implementation Cost **(Not OOOOa)**	$378,000	$546,000	$582,000
Component Gas Recovered MMSCF	90	135	126
Component Leak MCF/Well Surveyed	29	25	23
Component Leak Recovery Value (US $)**	$270,000	$274,000	$245,000

Source: Southwestern Energy, EPA Natural Gas STAR Methane Challenge Annual Implementation Workshop, October 25, 2017

* 2234 components found leaking relative to an estimated component count of over 3.8 million between 2014 and 2016 at 14,281 wells.

** 2014 based on $3/MMSCF after royalty reduction, 2015 based on $2.03/MMSCF after royalty reduction; 2016 based on $1.95/MMSCF after royalty reduction

This Independent Operator anticipates there may be some increase in costs to comply with the administrative burden under the Subpart OOOOa LDAR relative to LDAR in its voluntary programs.

4. Should EPA amend the above mentioned phase-in periods in the 2016 Rule instead of simply staying the requirements? What is the appropriate length of a phase-in period to address the challenges sources are experiencing in carrying out the requirements in the 2016 Rule?

- One Independent Operator believes that a phase-in approach is more appropriate to address the concerns of operators and service industry that will be contracted to meet compliance requirements. The phase-in period should be at least two years, but could be up to five years based on the EPA's estimates of when equipment and service companies will be available to support operator's requirements.

  The EPA's original compliance schedule required operators to meet initial compliance with Subpart OOOOa within 60 days of the regulation being published to the Federal Register. The rule provided a brief phase-in for operators to begin using equipment for Green Completions and one year to complete the initial fugitive gas inspections. At the same time, the EPA had more than a year to develop a method to accept the required data from operators' compliance activities. The EPA was several months late publishing the data collection template for operators to begin the reporting process.

  The EPA was unable to meet the original compliance schedule, but only had a fraction of the work to complete. 60 days was not a realistic schedule for operators to achieve compliance with the many facets of this regulation. The Independent Operator believes that a minimum phase-in period of two years is possible, but a five-year phase-in period is more appropriate. Subpart OOOOa is an extensive and complex regulation that will require significant resources from industry to understand the regulation and to develop and implement compliance programs.

  During the phase-in period, the EPA should continue to evaluate opportunities to reduce the burden placed on operators while continuing to meet the intent of the regulation. Opportunities to reduce the burden could include: reducing the volume of documentation that is required for every operator to collect, store, and report annually; implementing the low production well exemption that was included in the proposed rule; and implementing lower cost inspection tests such as soap bubble test for inspecting fugitive gas emission components.

- LINN believes that the proposed time periods are sufficient for implementation.

- Another Independent Operator favored staying the rule to provide regulatory certainty. Many of the requirements are ambiguous and overly burdensome. The regulated community would be required to comply with potentially two different versions of the rule and currently under an ambiguous rule that leaves many of the requirements uncertain.

- Range Resources suggested a minimum phase-in period of one year for a qualified Professional Engineer to become familiar with the field assets that are subject to the CVS requirements. The recent downturn in the production segment of the industry has created challenges in retaining experienced Professional Engineers to design and review newer CVS.

<u>Fugitive Emissions Requirements</u>

5. How is the availability of contractors and monitoring instruments, and the impact on owners and operators complying with the requirements at well sites and compressor stations impacting:

(i) requesting and receiving approval for the use of an AMEL and the applicability of the fugitive emissions requirements to low production well sites; and

- The Independent Producers' position on the fugitive emissions requirements is set forth in the "General Comments," because of its importance to its members.

- Section 111(h) of the CAA outlines the procedures for getting AMEL work practices approved and requires the person applying to show "equivalency" in emissions reduction as compared to current practice in the rule. AMEL also requires a public notice of application in the Federal Register, with a comment period and an opportunity for public hearing. This process is labor intensive, time consuming and provides little incentive to use it. Adherence to Section 111(h) requirements is too burdensome, not feasible, and not necessary. The American Petroleum Institute ("API") overarching recommendation is that the pathway for approval for state equivalency and emerging technology not be required to adhere to Section 111(h).

<u>Emerging Technology:</u>

New leak detection technologies are in development and various operators are partnering with manufactures to pilot new, cutting edge technologies. These technologies have the potential to be more effective and efficient at detecting leaks than methods approved under the rule. So that innovation is not stifled but rather encouraged, the EPA should provide a reasonable and streamlined pathway for approval under the rule. At a minimum, API recommends at a minimum that the EPA allow modeling to show performance of technology and/or "equivalency" in emission reduction, require only limited monitoring data to be collected, allow manufacture/vendor to apply for approval, and allow approved technology to be used for all sites subject to rule.

The Independent Producers suggest the following changes to Subpart OOOOa to allow more entities to utilize the AMEL provisions:

- Allow modeling to show performance of technology and/or "equivalency" in emission reduction (as required per Section 111(h));
- Require only limited monitoring data to be collected (just data that are needed to plug into model);
- Allow manufacture/vendor to apply for approval (not operator as its currently written); and
- Allow approval of technology to be used for all sites subject to rule (not a site-specific approval as rule is currently written)

State Equivalent LDAR Programs:

Additionally, state LDAR programs should be deemed alternative compliance, or "equivalent," if the requirements are included in a state enforceable permit and meets minimum threshold requirements in regard to frequency and repair time frames. The EPA took a similar approach for tanks in Subpart OOOOa. Requiring operators to comply with two concurrent, yet different, LDAR programs with the same end goal, at the same sites is burdensome, costly and logistically difficult.

- Devon supports revising the AMEL provisions so that compliance with any similar state LDAR requirements meets Subpart OOOOa requirements in that state and support a much simpler AMEL for other LDAR technologies.

(ii) for securing certified monitoring survey contractors and monitoring instruments

- A number of the larger Independent Operators indicated they purchased the necessary equipment and received the necessary training to bring the operations in-house.
- One Independent Operator indicated securing equipment with a single contractor was feasible for the initial monitoring surveys in 2017. It took approximately 4 months with a single camera and operator to survey 70 LDAR facilities. It took about 3 months to plan this work out with the contractor.

In evaluating whether to purchase a camera the main bottleneck the company found was with recalibration time for the cameras. This summer it stood at about 3 months. Between the recalibration time and inclement weather days it appears a single camera will only be operational about half the year. While this did not affect the initial LDAR surveys, it would logically be a significant problem on the next round of surveys, which the industry has yet to experience.

The Independent Operator did not find any contractors who know how (but all had varied opinions) to comply with the rules and still much uncertainty on what is required and expected especially in regards to reporting and recordkeeping. Each company interviewed had a different view on the regulations and there is no consensus on what the 120 pages of text in Subpart OOOOa actually mean and require of well operators.

6. Should the phase-in period be extended, and if so the appropriate length of the phase-in period to allow for an adequate buildup of the personnel and equipment required for meeting the fugitive emissions requirements? Does the impact of this requirement and any feasibility issues affect only a few sources or is this a systemic issue related to many sources?

- One Independent Operator found that the availability of personnel and equipment, or lack thereof, in the Illinois Basin is systemic; this is a problem for all of the operators in the basin. All of the major exploration and production companies left the Illinois Basin decades ago. This basin only produces approximately 30,000 per day, which does not attract large companies or significant investment.

  Most of the wells in the Illinois Basin are marginal/low production wells with low gas to oil ratios. Most of the wells require pumping units to be installed just to begin production because the reservoir pressure is very low. The feasibility to implement a basin-wide program with qualified fugitive gas emission inspection companies and qualified Profession Engineers is very low.

  A minimum of a two-year phase-in period, with consideration to extend to five years would provide an opportunity for contractors to meet the needs of major basins around the United States and then begin to consider extending their business model into smaller basins around the country. At this point, none of the service companies that support major oil and gas production basins are interested in establishing a presence in legacy basins such as the Illinois Basin.

  In addition to the Illinois Basin being a legacy basin, the oil and gas exploration and production business segment has been financially struggling to survive over the past three years. With little indication that the financial stress that is currently applied to the industry being abated, most service companies are more focused on surviving than incurring the risk to expand into a new basins with small business growth potential.

- Range Resources is of the opinion that the phase-in period should be extended a minimum of 12 months to train additional, dedicated staff and/or consultants for surveys. Existing experienced staff have been used to fulfill initial regulatory requirements; however, additional trained staff or consultant resources will be needed to perform the ongoing periodic surveys. New OGI operators will require an eye exam to identify color blindness issues, safety training, instrument training, education in infrared theory and operation, process equipment operation, diagnostics, and software and report writing.

- Another Independent Operator is of the opinion the rule should be stayed until it is revised to provide regulatory clarity and reasonable reporting and recordkeeping requirements. The Independent Operator also believes that a reasonable phase-in time frame might be an annual percentage of surveyed facilities to allow companies to determine how to adequately comply (*e.g.*, 10 facilities in 2018, 25% in 2019, 50% in 2020, 75% in 2021, and 100% by 2022).

7. **Applicability of the fugitive emissions requirements to third-party equipment at well sites which is ancillary to production (e.g., equipment such as meters owned by midstream operators). The 2016 Rule requires that all fugitive emissions components at a well site be monitored and repaired, but there has been confusion as to the appropriate scope of components that are included in the definition of the well site for the fugitive emissions requirements. EPA received feedback that ancillary midstream assets (*e.g.*, meters) should be excluded from the fugitive emissions requirements because they are owned by legally distinct companies from the well site owner and operator and could have limited emissions. EPA is soliciting comment on this feedback, specifically:**

    (i) **What legal and logistical issues could prevent midstream operators, or other operators of ancillary third-party equipment, from compliance with the 2016 Rule? What are suggestions for addressing this issue?**

- Devon supports the removal of the requirement for LDAR of third-party on-site equipment such as meter runs, etc., that is not owned by the operator of the well site or compressor station.

- One Independent Operator is of the opinion that the small number of midstream components and miniscule associated emissions at a well site do not justify additional separate regulation. There is no regulatory justification for aggregating these components and their emissions with third-party controlled and operated assets. As such, midstream components should be exempt from the rule.

(ii) What number of contracts that would need to be renegotiated and what is the associated burden/cost to the regulated community of doing so?

- LINN believes this is huge burden and short coming of Subpart OOOOa. Hundreds of midstream contracts would need to be re-negotiated within the company in order to account for this level of compliance because LINN is not responsible for the maintenance of these meters or facilities and cannot even legally touch them. The contract would have to be amended in order to properly ensure compliance because existing contracts do not provide the company with the authority to dictate maintenance of these meters to the midstream companies.

- Similarly, MarkWest argues the EPA cannot force a party to aggregate it emission sources with a third-party by contract or any other vehicle. Aggregation principles should recognize the separation of third-party owned and operated assets. There is not an enforceable, constitutional method to make a third-party midstream operator combine its assets for permitting and/or monitoring purposes with a well operator.

- Another Independent Operator argued that the midstream gas contracts would have to be re-negotiated or at a minimum would place an additional $2,000/year for a separate survey cost on each well site to third-parties. Many of these third parties could fall under the small business definition and would ultimately bear the costs.

(iii) In light of the above, should EPA stay or otherwise extend the phase-in period as it applies to third-party equipment on well sites until after EPA has addressed this compliance issue?

- During development of Subpart OOOOa, the EPA failed to recognize many of the complex issues that exist within the oil and gas exploration and production business segment. The EPA further developed a major regulation with a "one-size-fits-all" perspective in an effort to publish the regulation prior to the end of the Obama Administration instead of working with industry representatives to co-develop a comprehensive regulation. Many comments that were provided to the EPA through several venues (such as the Small Business Administration office or public comment period) were ignored by the Administration to meet the environmental agenda. As a result, the EPA and industry continue to expend vast resources to address issues with the regulation.

Addressing the interface between business entities will be a challenging issue for many companies to develop solutions. In most cases, this will not be a quick resolution as corporate contract departments will need to develop options and select the best option available. Options will need to be reviewed by legal departments, which could substantially increase the time to implement solutions. Many of these reviews will take time and involve a variety of resources to implement a solution.

The interface between equipment of separate legal entities will create legal and logistical challenges that will need to be addressed to meet compliance requirements. When a shutdown occurs that will result in a financial loss (*i.e.*, shut in production), companies will need to develop solutions to address these occurrences. Not only will companies incur maintenance cost to address fugitive emissions, shutdown and startup costs must also be considered as considerable labor may be required to facilitate these events.

We recommend that the EPA rely upon data provided by operators and equipment manufacturers to perform a risk assessment for the typical equipment that exists at the interface point where companies will need to spend a time developing agreements related to addressing fugitive emissions. If data supports that the equipment has a high probability to emit fugitive emissions, companies should be required to develop solutions. If data shows that a low probability of fugitive emissions exists the EPA should exempt this equipment from leak detection and repair requirements while the equipment is operating.

- Given the length of time it takes to amend a contract, LINN believes a 3 or 4-year phase-in period would be better for this item.

- MarkWest believes the EPA should clarify that the rule applies to well site equipment owned by the well-site owner or operator, and that third-party equipment should not be considered part of the well-site, and should not require monitoring, absent the volume of emissions or components of such third-party equipment exceeding a certain threshold, the amount of such threshold to be the subject of a future valid rule-making process.

- Similarly, Range Resources believes the ancillary midstream assets and associated emission requirements should be defined separately from well site monitoring requirements.

Third-party equipment should not be the responsibility of the well site operator since employees are not permitted to operate or repair such equipment. In some cases, access is not available to third-party equipment due to security arrangements. The current regulations require repairs to be made as soon as practicable, which is typically during the monitoring survey and no late than 30 days after detection.

8. **Regarding technical, safety, and environmental issues associated with the delay of repair provisions in the 2016 Rule, EPA proposed that if "repair or replacement [of**

a leaking fugitive emissions component] is technically infeasible or unsafe to repair during operation of the unit, the repair or replacement must be completed during the next scheduled shutdown or within 6 months, whichever is earlier." Stakeholders responded with concerns about "delays lasting longer than six months due to availability of supplies needed to complete repairs and information regarding the frequency of delayed repairs." Some commenters also indicated that in some cases, requiring prompt repairs could lead to more emissions than if repairs were able to be delayed, for example if a well shut-in or vent blow-down is required. EPA has received feedback that requiring repair or replacement of fugitive emissions components during unscheduled or emergency vent blowdowns could result in natural gas supply disruptions, safety concerns, and increased emissions. Stakeholder feedback suggests that compliance with this provision could result in prolonged shutdowns impacting natural gas supply if necessary parts and skilled labor is unavailable, and avoidable blowdowns resulting in greater emissions than the leaking component. Feedback additionally indicates that these events may not necessarily result in the blowdown of all equipment located onsite and, thus, the equipment needing repair may not have been affected by the blowdown. EPA is soliciting comment on this feedback, specifically:

(i) What are the shutdown, shut-in, or blowdown scenarios that result in the technical, safety, and environmental issues described? And suggestions for addressing these issues.

- Many operators are concerned with the safety issues associated with forced, unplanned shutdowns for marginal environmental gain. For safety and technical concerns, operators may have to shut-in production to replace thief hatches on tanks, where such tanks are connected by a common overhead vapor line that does not allow for isolation of tanks for repairs. The Independent Producers recommend Subpart OOOOa require (technically infeasible/unsafe) repairs at the next scheduled shutdown and *not* set an arbitrary six-month deadline.

  See the language in 40 CFR § 60.482-9a(a) (NSPS Subpart VV for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry) and as relied upon by natural gas processing plants in NSPS Subpart KKK (40 CFR § 60.633(b)(3)(i)) and in NSPS Subpart OOOO (40 CFR § 60.5401(b)(3)(i)) providing, "[d]elay of repair for equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown."

- One Independent Operator commented that it had encountered ESP cables around wells heads, compressor parts on the intake or discharge, main gas supply lines at production facilities. If any of these are found to have small leaks, a large amount of equipment, wells, and gas usually will be required to be shut-in. Almost all of this equipment is designed to be run continually usually requires some amount of fits and starts when re-starting which inevitably leads to gas discharges while each component re-pressurizes and re-starts. Each re-start exposes multiple employees to equipment start-up risks, which is almost always the most dangerous aspect of any facility operations. Shutting down and de-pressurizing each vessel is the only safe method to allow repairs to be made which is a trade-off for personal safety and startup emissions.

- Blowdowns themselves can result in significant emissions. Both on tanks and piping, and gathering lines. For example, in order to repair a small leak on a thief hatch, you may have to blowdown the tank, or if there is a series of production tanks, would have to blowdown all to repair one.

  In regard to the delay of repair, if you shut down a site to do a repair, there may be more venting to do the repair than what was originally leaking.

  Anytime gas is vented, there are safety concerns due to possible flammability and the potential relaease of hydrogen sulfide.

  And the language re: repair at next shutdown or within 6 months creates a backlog and logistics mess trying to track all of this. Repair should simply be required at the next scheduled shutdown and the "or within 6 mo." language should be removed.

(ii) Should EPA stay or otherwise extend the phase-in period as it applies to equipment requiring delay of repair at well sites and compressor stations until after the EPA has addressed this compliance issue.

- The Independent Producers strongly support a stay or an extension of the phase-in period while the EPA works to address the issues associated with this requirement. Any unscheduled shut down may cause problems from a technical, safety, or environmental standpoint because the cause of the unscheduled shutdown could be almost anything. If it is a safety or environmental concern, the first priority is always going to be these issues first, getting the site operational second and repairs to unrelated items third.

  Further, these kinds of repairs are often difficult to schedule with roustabout crews with unscheduled shutdowns because you never know when they are going to occur nor how long they will last. You may have one tomorrow or in 6 months and sometimes the unscheduled shut down may last for only 30 minutes or it may last for days.

The EPA should remove the unscheduled shutdown part and only require the repair during the next planned shutdown. This would allow companies to better prepare and schedule repairs and alleviate all logistical or environmental, health and safety concerns.

- One Independent Operator supports the concept to not shut down and repair equipment that will result in greater emissions if the leaking fugitive emission component is not repaired when the leak occurs. Companies incur substantial risk and financial burdens when operating equipment is shut down for maintenance. The Independent Operator does believe that these occurrences will be relatively low frequency, which will minimize the environmental impact. When this type of event occurs, the operator should quantify the emissions from the existing fugitive emission source and the emissions as a result of the shutdown. If the leaking fugitive gas emission source is considerably less than the impact of shutting down equipment for repair, then temporary solutions should be explored to minimize the impact while safely operating the equipment.

Well Site Pneumatic Pump Requirements

9. EPA proposed to stay for 2 years the requirements for well site pneumatic pump standards while it reconsiders the technical infeasibility exemption and the definition of "greenfield site." EPA acknowledges that the technical infeasibility exemption that the EPA finalized in the 2016 Rule adopted a different approach than previously applied to the oil and gas industry and created an unanticipated and unnoticed distinction between "greenfield" (new development) and "non-greenfield" sites. Some stakeholders have suggested that this distinction has caused confusion among owners and operators on what sites qualify for the technical infeasibility flare. EPA is soliciting comment on:

(i) What are the technical constraints of new "greenfield" sites and specific site designs such as these which present challenges in implementing the well site pneumatic pump requirements in the 2016 Rule?

- Range Resources believes the technical feasibility of controlling emissions from a pneumatic pump is a function of its location, relative to a process or the control device. Pneumatic pumps that are near processes or control devices are more likely able to be controlled than units that are situated at greater distances. Alternatively, units that are located too far from available control options will likely not be technically feasible to control. To comply with the emission reduction requirements, site equipment layouts will need to be revised to strategically locate pneumatic pumps.

- LINN states that a new field that is being developed will have numerous unknowns such as no available oil/water samples, no production information, no sour gas information, etc. It is virtually impossible to adequately design a system to handle these unknowns for any greenfield site. No matter how well the system is designed, it is going to have to be modified in the field in order to get it working properly and equipment will necessarily be shuffled on and off site. This process can easily take upwards of 6 months to a year and you may not have a good idea about how a greenfield site will work until you have drilled multiple wells in the area.

- Devon supports removing the "greenfield" and "brownfield" distinction for determining viability of controlling pneumatic pump emissions. Operators should be able to show technical infeasibility in all cases.

(ii) Should EPA extend the phase-in period for 2 years (the time period the EPA estimates its reconsideration process and the issuance of the resulting rule would take), so that the EPA may provide the necessary clarification or revision in conjunction with its reconsideration process, thereby addressing all issues in one rulemaking?

The Independent Producers support at least a two-year phase-in – it should be extended to 3 or 4 years.

(iii) Should EPA extend the phase-in period (and if so for what length of time) for the well site pneumatic pump requirements as an alternative to the proposed stay of these requirements?

The Independent Producers support at least a two-year phase-in – it should be extended to 3 or 4 years.

<u>Professional Engineering Certification Requirements</u>

10. EPA proposed to stay for 2 years the requirement for closed vent system certification by professional engineer while the EPA evaluates the benefits, as well as the cost and other compliance burden, associated with this requirement. EPA received feedback that owners and operators had to reanalyze and potentially redesign the closed vent systems in order to meet this certification requirement. EPA received feedback from some stakeholders that owners and operators have struggled to obtain professional engineers to complete these certifications primarily because of a shortage of professional engineers certified in each state of operation with experience in the design of these systems. EPA is soliciting comment on:

(i) What is the availability of professional engineers qualified in each state of operation and experienced in the oil and gas field?

Based on the responses from members of the Independent Producers, the answer is "it depends." It depends on location and size of the company.

(ii) What are the costs associated with completing the certification requirements in the 2016 Rule?

The Independent Producers indicated completing the certification requirements cost between $1,200 and $2,500.

(iii) What are the costs of reanalyzing and redesigning sites in order to comply with the requirements of the 2016 Rule?

As indicated above – "it depends." One Independent Operator provided the following rough estimates:

- Emissions/permit evaluations: $2,000;
- New Flare cost: 20,000;
- Redesign existing well (vent line, scrubber pots): $5,000 plus, if applicable, a new combustor and associated equipment; and
- Addition of by-pass flow meter: $2,500 meter and $1,500 additional equipment.

(iv) Should EPA providing a period to phase in this certification period as an alternative to staying this requirement?

The Independent Producers would prefer the certification provisions be removed in their entirety but a phase-in period is needed

If the EPA has any questions or concerns regarding the information and comments provided above, please do not hesitate to contact me.

Sincerely,

James D. Elliott

cc: Bill Wehrum, EPA (via E-mail)
Amanda Gunasekara, EPA (via E-mail)
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August 2, 2016

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

Re: Request for Administrative Reconsideration EPA's Final Rule "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources"

Dear Administrator McCarthy:

The following trade associations hereby submit this petition for administrative reconsideration of the final rule entitled "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources," published at 81 Fed. Reg. 35824 (June 3, 2016) ("Subpart OOOOa" or "Methane NSPS"). We request that you take the time to review what and who these trade associations represent and not simply jump to the issues we are seeking reconsideration of. Many of these trade associations have been around since or before the 1950s. The trade associations represent the "independent" exploration and production companies – from the "mom and pop" operations to some of the larger producers in the country – but that is all they do and it is all they know. Subpart OOOOa, as finalized, will have a disproportionate impact on independents and especially independents that constitute "small business" under the Regulatory Flexibility Act. The issues raised in this petition fall into two categories: 1) issues that are entitled to reconsideration under Section 307(d)(7)(B) of the Clean Air Act ("CAA"), 42 U.S.C. § 7607(d)(7)(B), where it is impracticable to raise an objection during the period of public comment or if the grounds for such an objection arise after the public comment period (but within the time specified for judicial review), and if such objections are of central relevance to the outcome of the rule; and 2) issues the independents commented on, either through their trade association or as an individual company, that the U.S. Environmental Protection Agency ("EPA" or "Agency") failed to address in the final rule and that will have devastating impacts to the exploration and production segment of the industry if not addressed.

The national and state level trade associations joining in and filing this petition for reconsideration, collectively referred to as the "Independent Associations," are described below.

The Independent Petroleum Association of America ("IPAA") is an incorporated trade association that represents thousands of independent oil and natural gas producers and service companies across the United States that are active in the exploration and production segment of the industry, which often involves the hydraulic fracturing of wells. IPAA serves as an informed voice for the exploration and production segment of the industry, and advocates its members' views before the United States Congress, the Administration and federal agencies.

The American Exploration & Production Council ("AXPC") is an incorporated national trade association representing 29 of America's largest and most active independent oil and natural gas exploration and production companies. AXPC members are "independent" in that their operations are limited to exploration for and the production of oil and natural gas. Moreover, its members operate autonomously, unlike their fully integrated counterparts, which operate in additional segments of the energy business, such as downstream refining and marketing. AXPC members are leaders in developing and applying the innovative and advanced technologies necessary to explore for and produce oil and natural gas, both offshore and onshore, from non-conventional sources in environmentally responsible ways.

The Domestic Energy Producers Alliance ("DEPA") is a nationwide collaboration of 25 coalition associations, representing about 10,000 individuals and companies engaged in domestic onshore oil and natural gas production and exploration. Founded in 2009, DEPA gives a loud, clear voice to the majority of individuals and companies responsible for enduring work to secure our nation's energy future.

The Eastern Kansas Oil & Gas Association ("EKOGA") is a nonprofit organization founded in 1957 to become a unified voice representing the unique interests of eastern Kansas oil and gas producers, service companies, suppliers and royalty owners on matters involving oil and gas regulations, safety standards, environmental concerns and other energy related issues.

The Illinois Oil & Gas Association ("IOGA") was organized in 1944 to provide an agency through which oil and gas producers, land owners, royalty owners, and others who may be directly or indirectly affected by or interested in oil and gas development and production in Illinois, may protect, preserve and advance their common interests.

The Independent Oil and Gas Association of West Virginia, Inc. ("IOGA-WV"), is a statewide nonprofit trade association that represents companies engaged in the extraction and production of natural gas and oil in West Virginia and the companies that support these extraction and production activities. IOGA-WV was formed to promote and protect a strong, competitive, and capable independent natural gas and oil producing industry in West Virginia, as well as the natural environment of their state.

The Indiana Oil and Gas Association ("INOGA") has a rich history of involvement in the exploration and development of hydrocarbons in the State of Indiana. INOGA was formed in 1942 and historically has been an all-volunteer organization principally made up of representatives of oil and gas exploration and development companies (operators), however, it has enjoyed support and membership from pipeline, refinery, land acquisition, service, supply, legal, engineering and geologic companies or individuals. INOGA has been an active representative for the upstream oil and gas industry in Indiana and provides a common forum for this group. INOGA represents its membership on issues of state, federal, and local regulation/legislation that has, does and will affect the business of this industry. INOGA is a

501(c)(6) trade association incorporated as Non-Profit Domestic Corporation under the statutes of Indiana.

Since 1940, the International Association of Drilling Contractors ("IADC") has exclusively represented the worldwide oil and gas drilling industry. IADC's contract-drilling members own most of the world's land and offshore drilling units that drill the vast majority of the wells producing the planet's oil and gas. IADC's membership also includes oil-and-gas producers, and manufacturers and suppliers of oilfield equipment and services. Through conferences, training seminars, print and electronic publications, and a comprehensive network of technical publications, IADC continually fosters education and communication within the upstream petroleum industry.

The Kansas Independent Oil & Gas Association ("KIOGA") is a nonprofit organization founded in 1937 to represent the interests of oil and gas producers in Kansas, as well as allied service and supply companies. Today, KIOGA is a trade association with over 4,200 members involved in all aspects of the exploration, production, and development of crude oil and natural gas resources.

The Kentucky Oil & Gas Association ("KOGA") was formed in 1931 to represent the interests of Kentucky's crude oil and natural gas industry, and more particularly, the independent crude oil and natural gas operators as well as the businesses that support the industry. KOGA is comprised of 220 companies which consist of over 600 member representatives that are directly related to the crude oil and natural gas industry in Kentucky.

The Michigan Oil And Gas Association ("MOGA") represents the exploration, drilling, production, transportation, processing, and storage of crude oil and natural gas in the State of Michigan. MOGA has nearly 850 members including independent oil companies, major oil companies, the exploration arms of various utility companies, diverse service companies, and individuals. Organized in 1934, MOGA monitors the pulse of the Michigan oil and gas industry as well as its political, regulatory, and legislative interest in the state and the nation's capital. MOGA is the collective voice of the petroleum industry in Michigan, speaking to the problems and issues facing the various companies involved in the state's crude oil and natural gas business.

The National Stripper Well Association ("NSWA") was founded in 1934 as the only national association *solely* representing the interests of the nation's smallest and most economically-vulnerable oil and natural gas wells before Congress, the Administration and the Federal bureaucracies. It is the belief of NSWA that producers, owners, and operators of marginally-producing oil and gas wells have a unique set of needs and concerns regarding federal legislation and regulation. NSWA is a member based trade association with nearly 800 members nationwide across 43 states.

The North Dakota Petroleum Council ("NDPC") is a trade association representing more than 590 companies involved in all aspects of the oil and gas industry, including oil and gas production, refining, pipeline, transportation, and storage, as well as mineral leasing, consulting, legal work, and oil field service activities in North Dakota, South Dakota, and the Rocky

Mountain Region. Established in 1952, NDPC's mission is to promote and enhance the discovery, development, production, transportation, refining, conservation, and marketing of oil and gas in North Dakota, South Dakota, and the Rocky Mountain region; to promote opportunities for open discussion, lawful interchange of information, and education concerning the petroleum industry; to monitor and influence legislative and regulatory activities on the state and national level; and to accumulate and disseminate information concerning the petroleum industry to foster the best interests of the public and industry.

The Ohio Oil & Gas Association ("OOGA") is a trade association with over 2,600 members involved in all aspects of the exploration, production, and development of crude oil and natural gas resources within the State of Ohio. OOGA represents the people and companies directly responsible for the production of crude oil, natural gas, and associated products in Ohio.

Founded in 1955, the Oklahoma Independent Petroleum Association ("OIPA") represents more than 2,500 individuals and companies from Oklahoma's oil and natural gas industry. Established by independent oil and natural gas producers hoping to provide a unified voice for the industry, OIPA is the state's largest oil and natural gas association and one of the industry's strongest advocacy groups.

The Pennsylvania Independent Oil & Gas Association ("PIOGA") is a non-profit corporation that was initially formed in 1978 as the Independent Oil and Gas Association of Pennsylvania ("IOGA of PA") to represent the interests of smaller independent producers of Pennsylvania natural gas from conventional limestone and sandstone formations. Effective April 1, 2010, IOGA of PA and another Pennsylvania trade association representing conventional oil and natural gas producers, Pennsylvania Oil and Gas Association ("POGAM"), merged and the name of the merged organization changed to its present name. PIOGA's membership currently is approximately 500 members: oil and natural gas producers developing both conventional and unconventional formations in Pennsylvania; drilling contractors; service companies; engineering companies; manufacturers; marketers; Pennsylvania Public Utility Commission-licensed natural gas suppliers ("NGSs"); professional firms and consultants; and royalty owners. PIOGA promotes the interests of its members in environmentally responsible oil and natural gas operations, as well as the development of competitive markets and additional uses for Pennsylvania-produced natural gas.

The Texas Alliance of Energy Producers ("Texas Alliance") became a statewide organization in 2000 with the merger of two of the oldest oil & gas associations in the nation: the North Texas Oil & Gas Association and the West Central Texas Oil & Gas Association. The Texas Alliance is now the largest statewide oil and gas association in the country representing Independents. With members in 34 states, the Texas Alliance works on behalf of our members at the local, state, and federal levels on issues vital to the industry.

The Texas Independent Producers & Royalty Owners Association ("TIPRO") is a trade association representing the interests of 3,000 independent oil and natural gas producers and royalty owners throughout Texas. As one of the nation's largest statewide associations representing both independent producers and royalty owners, members include small family businesses, the largest, publicly-traded independent producers, and mineral owners, estates, and trusts. Members of TIPRO are responsible for producing more than 85 percent of the natural gas and 70 percent of the oil within Texas, and own mineral interests in millions of acres across the state.

Chartered in 1915, the West Virginia Oil and Natural Gas Association ("WVONGA") is one of the oldest trade organizations in the State, and is the only association that serves the entire oil and gas industry. The activities of our members include construction, environmental services, drilling, completion, gathering, transporting, distribution, and processing.

The Independent Associations respectfully request the Agency reconsider the following issues.

A. SECTION 307(D)(7)(B) RECONSIDERATION ISSUES

1. The low production well (15 barrels of oil equivalent ("boe")/day) exemption from leak detection and repair ("LDAR") and reduced emission completions ("RECs") requirements should be reinstated in the final rule and the requirements regarding low production wells should be stayed pending reconsideration.

In the proposed rule, EPA sought comment on and proposed to exclude low production wells (i.e., those with an average daily production of 15 barrel equivalents or less per day) from REC and LDAR requirements. 80 Fed. Reg. 56633-34, 56639, 56665 (Sept. 18, 2015). The trades representing the independents uniformly supported the low production well exemptions. Based on the preamble discussion of the low production well exemption, EPA listened to, understood, and accepted the arguments and comments set forth by "small entities" during the Small Business Advocacy Review Panel ("Panel") process, in compliance with Section 609(b) of the Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 ("SBREFA"). Small entity representatives ("SERs"), including trade associations that are part of this petition, met with the Panel, which included EPA personnel, on May 19, 2015, and June 18, 2015, and submitted written comments. The SERs' message was clear – the potential REC and LDAR requirements would be the most onerous aspect of any additional controls on their operations. The SERs explained how and why these potential requirements would disproportionality impact small entities. The SERs explained the physical differences associated with low production wells (e.g., primarily pressure and volume) and the marginal profitability of low production wells. EPA seemed to "get it" and stated in the preamble:

> We believe the lower production associated with these wells [low production wells] would generally result in lower fugitive emissions. It is our understanding that fugitive emissions at low production well sites are inherently low and that such well sites are mostly owned and operated by small businesses. We are concerned about the burden of the fugitive emission requirement

> on small businesses, in particular where there is little emission reduction to be achieved.

80 Fed. Reg. 56639. Numerous oil and natural gas trade associations, including many of the parties to this petition filed comments in support of the exemptions and the rationale behind them.

Despite the information provided to EPA during the SBREFA process and Final Report of the Panel, EPA reversed course in the version of Subpart OOOOa and did not provide the low production exemption from either the REC or LDAR requirements. In the preamble to Subpart OOOOa that "one commenter" stated that low production wells have the "potential" to emit high fugitive emissions; "another commenter" stated that the LDAR survey should be conducted quarterly or monthly; and "one commenter" provided an estimate that a "significant" number of wells would be excluded under the low production well exemption. What appears to be EPA's principal reason for reversing course is that

> [S]takeholders indicated that well site fugitive emissions are not correlated with levels of production, but rather based on the number of pieces of equipment and components. Therefore, we believe that the fugitive emissions from low production and non-low production well sites are comparable.

81 Fed. Reg. 35856. EPA's rationale, that fugitive emissions are a function of the number and types of equipment, and not operating parameters such as pressure and volume, is inconsistent with EPA's justification for what constitutes a "modification" for an existing well site. EPA assumes that fracturing or refracturing an existing well will increase emissions because of the additional production, i.e., the additional pressure and volume. EPA cannot ignore the laws of physics to the detriment of low production wells in one instance and then "honor" them in another context to eliminate an "emissions increase" requirement in the traditional definition of "modification."

The estimation or correlation of fugitive emissions with the number or types of components at low production versus non-low production wells was not discussed during the Panel process nor was comment sought by EPA in the proposed rule. If EPA proposed to correlate fugitive emissions at low production well sites with the number or types of components – in place of operating parameters such as line pressure and volume, independents would have been put on notice that additional information and comments were needed on the issue. No such comment was sought and EPA rationale and revocation of the low production well exemption is confounding. An administrative stay of the REC and LDAR requirements to low production wells is warranted pending outcome of the reconsideration proceeding. Although the effective date of the requirements has been extended 180 days, the impact of the regulations is immediate on low production wells. The marginal profitability will mean that many wells will be shut in instead of making the investment to conduct LDAR surveys. Similarly, low production wells that are currently in the planning stage will be reevaluated to take into consideration the additional costs of RECs and it is likely that the plans to drill many wells will be scrapped. For the reasons set forth above, it is appropriate for EPA to grant reconsideration of this issue.

2. The requirement in Section 60.5375a of Subpart OOOOa that requires a separator be "onsite during the entirety of the flowback period" was not part of the proposal and imposes an unnecessary cost on many conventional wells drilled by independents.

From the inception of the Subpart OOOO rulemaking, independent operators have informed the Agency that operating parameters during flowback of certain hydraulically fractured wells, often what is referred to as "conventional" wells, are such that a separator does not "work" – or as EPA has focused on is not technically feasible. EPA initially seems to understand this point and states:

> … we do not have sufficient data to consistently and accurately identify the subcategory or types of wells for which these circumstances occur regularly or what criteria would be used as the basis for an exemption to the REC requirement such that a separator would not be required to be onsite for these specific well completions. In order to accommodate these concerns raised by commenters, the final rule requires a separator to be onsite during the entire flowback period for subcategory 1 wells (i.e., non-exploratory or non-delineation wells, also known as development wells), but does not require performance of REC where a separator cannot function. We anticipate a subcategory 1 well to be producing or near other producing wells. We therefore anticipate REC equipment (including separators) to be onsite or nearby, or that any separator brought onsite or nearby can be put to use. For the reason stated above, we do not believe that requiring a separator onsite would incur cost with no environmental benefit.

81 Fed. Reg. 35881. Independent Associations take issue with the conclusion that requiring a separator onsite throughout the entire flowback period would incur no cost. The cost of having the separator on site is a significant cost and could be a limitation on the operations of certain operators. The existing regulations make clear that a separator must be utilized during the separation flowback stage and EPA has increased the record keeping and monitoring associated with the different stages of flow back. In addition to these requirements, there is the general duty clause to reduce emissions. The requirement to have a separator onsite throughout the flowback process is an unnecessary cost to many independent operators that provides no economic benefit. The proposed rule did not contemplate requiring a separator to be onsite throughout the flowback process and in fact inferred just the opposite. For the reasons set forth above, it is appropriate for EPA to grant reconsideration of this issue.

3. Subpart OOOOa added a variety of requirements associated with "technical infeasibility" that were not purposed or even mentioned in the proposed rule

that increase the cost of compliance with disproportionally impacts on independent operators.

While the Agency has appropriately accepted the concept that it is not technically feasible to implement certain controls, EPA added a number of requirements in Subpart OOOOa that were not proposed or discussed in the proposed rule:

- The final rule requires that Professional Engineers ("PE") certify connections of pneumatic pumps (§60.5393a) or closed vent systems (§60.5411a(d) are not technically feasible at brownfield sites. The certification by a PE will add considerable cost with no demonstrated benefits. As with many of these requirements. the independent operators do not have the ability in-house to meet these requirements and are dependent on third-party contractors. As EPA pushes the envelope on new/additional requirements, economies of scale favor the larger operators and to the extent the contractors are available for hire, it comes at a premium cost for the smaller entities and/or independent operators.
- Without discussion in the proposed rule, the Agency has also removed the "technical infeasibility" option for controls at "greenfields." Neither the proposed rule nor Subpart OOOOa define what constitutes a brownfield versus a greenfield. At some point in time a greenfield becomes a brownfield. Not only does the proposed rule fail to mention the concept of brownfield versus greenfield, Subpart OOOOa fails to provide any differentiation.
- The additional recordkeeping requirements added in Subpart OOOOa, at end of §60.5420a(c)(1)(iii)(A), associated with technical infeasibility, which were not part of the proposed rule, demonstrates that the Agency fails to understand that such requirements disproportionally impact small entities and many independent producers and operators.

The additional requirements associated with technical infeasibility were not only not addressed in the proposed rule, but the Agency failed to consider and address the disproportionate impact they would have on independent operators.

B. ADDITIONAL ISSUES IN NEED OF REVISION

The following issues were arguably addressed in some manner during the SBREFA and/or notice and comment process, but based on a review of the record, the Independent Associations believe they warrant additional discussion. The Independent Associations will provide the Agency additional information on these issues of concern.

1. The definition of "modification" as it relates to refractured wells and the LDAR requirements needs to be clarified and changed. The refracturing of wells does not necessarily mean emissions will increase. Emissions must increase to meet the NSPS definition of modification. As currently defined, Subpart OOOOa would unjustifiably subject "existing sources" that have not necessarily been modified to extensive and costly requirements.

2. Certain oil wells should be exempt from the LDAR requirements. Similarly, there should be a different definition of "low pressure well."

3. There should be an "off ramp" for the LDAR requirements when existing wells or new wells become "low production" or marginal wells.

4. Although Subpart OOOOa provides a state equivalency process for LDAR programs, the procedure set forth in the regulations (§60.5398a) is overly burdensome to the point that states are unlikely to avail themselves of the provisions.

5. The digital/video LDAR related requirements (§60.5420a) are unnecessary and should be removed.

6. EPA should reinstate options to reduce the emission surveys to annual surveys. While certain operators might prefer the consistency of bi-annual surveys, many independent operators and small entities would still benefit from the ability to reduce survey frequency by demonstrating few/no leaks during consecutive surveys.

7. Extended implementation periods are necessary and warranted for small entities that lack the bargaining power and resources (and the in-house capabilities) to contract with consultants to undertake the surveys, testing and documentation required by Subpart OOOOa. .

As indicated above, the Independent Associations will provide additional information on the issues raised above. In the interim, if the EPA has any questions or concerns, please do not hesitate to contact me.

Respectfully submitted,

James D. Elliott

Counsel to the Independent Associations

cc: Janet McCabe, EPA
Peter Tsirigotis, EPA
David Cozzie, EPA
Bruce Moore, EPA

Company Name:

Facility Name:

Wyoming Air Quality Standards and Regulations - Chapter 6, Section 2(c)(v)

Best Available Control Technology Control Cost Analysis Worksheet

(Based on Office of Air Quality Planning and Standards, EPA, OAQPS Control Cost Manual, Fourth Edition, EPA 450/3-90-006, January 1990, Section 2.3.2)

							Targeted Emission		
Reference No.	Site Rating (units)	Manufacturer	Model	Control Method	Controlled or Targeted Emission	Typical BACT (units)	without Control (TPY)	with Control (TPY)	
1		OGI Camera		Monitoring	VOC	50%	6.0	3.0	Semi-Annual
2		OGI Camera		Monitoring	VOC	60%	6.0	2.4	Quarterly

Reference No.	Interest Rate (i)	Control System Life (n)	Capital Recovery Factor (CRF)	Capital Investment (P)	Annual Maintenance Cost	Capital Recovery Cost (CRC)	Realized Economic Benefit
1	0.1	5	0.264	$110,000	$6,250	$29,018	$0
2	0.1	5	0.264	$110,000	$6,250	$29,018	$0

"n" is the control system economic life, typically thought to be 10-20 years.

"i" is the considered the annual pretax marginal rate of return on private investment (i.e., what it may cost you to borrow the money).

P is the capital investment required to install the controls (i.e., equipment purchase cost, installation/retrofit cost, engineering, etc.).

Annual Maintenance Cost is the yearly costs to maintain the control effectiveness (i.e., cleaning, testing, etc).

WDEQ DOES NOT INCLUDE Operating Costs (i.e., Mileage, leak repair costs (EPA uses in OOOOa analysis), cost of paying contractor or internal camera operator, etc.). These are included in PAW Analysis

CRC = CRF * P

CRC = Capital Recovery Cost (Annualized cost of control over the life of the control)

CRF = Capital recovery Factor P = Capital Investment

CRF = i(1+i)n/(1+i)n-1

i = Annual Interest Rate

n = Economic life of the control

Total Annual Cost (TAC) = Annual Maintenance Cost + Capital Recovery Cost - Realized Economic Benefit

Cost to Control = TAC / (Targeted Emission Volume Without Control - Targeted Emission Volumn with Control)

Reference Number	TAC ($)	Cost to Control ($/Ton)
1	$35,268	**$11,756**
2	$35,268	**$14,695**
		($9,797 in WDEQ Analysis)

Does the control have "Economic Reasonableness" and "Technical Practicability"?

The cost to control under the 2010 O&G Guidance ranged from a low of $6,300 per ton of VOCs to an upper bound of $14,700 per ton of VOCs. Based on the cost range, shown above, semi-annual and quarterly monitoring would be cost-effective for VOC emission control

Company Name:

Facility Name:

Wyoming Air Quality Standards and Regulations - Chapter 6, Section 2(c)(v)

Best Available Control Technology Control Cost Analysis Workshee t

(Based on Office of Air Quality Planning and Standards, EPA, OAQPS Control Cost Manual, Fourth Edition, EPA 450/3-90-006 , January 1990, Section 2.3.2)

Reference No.	Site Rating (units)	Manufacturer	Model	Control Method	Controlled or Targeted Emission	Typical BACT (units)	Targeted Emission		
							without Control (TPY)	with Control (TPY)	
1		OGI Camera		Monitoring	VOC	**50%**	6.0	3.0	Semi-Annual
2		OGI Camera		Monitoring	VOC	**60%**	6.0	2.4	Quarterly

Reference No.	Interest Rate (i)	Control System Life (n)	Capital Recovery Factor (CRF)	Capital Investment (P)	Annual Maintenance Cost	Annual Operating Costs	Capital Recovery Cost (CRC)	Realized Economic Benefit
1	0.1	5	0.264	$110,000	$6,250	$2,505	$29,040	$0
2	0.1	5	0.264	$110,000	$6,250	$65,011	$29,040	$0

"n" is the control system economic life, typically thought to be 10-20 years.

"i" is the considered the annual pretax marginal rate of return on private investment (i.e., what it may cost you to borrow the money).

P is the capital investment required to install the controls (i.e., equipment purchase cost, installation/retrofit cost, engineering, etc.).

Annual Maintenance Cost is the yearly costs to maintain the control effectiveness (i.e., cleaning, testing, etc).

WDEQ DOES NOT INCLUDE Operating Costs in Analysis (i.e., Mileage/Vehicle, Leak Repair Costs, recordkeeping and reporting, OGI operator costs, etc.

EPA uses all of these costs in OOOOa and CTG cost analyses.

Additional Operating Costs include:

Operating Cost	**Annual**	**Semi-Annual**	**Quarterly**
Travel/Vehicle	$13,005	$15,511	$20,521
~~Repair Costs~~	~~$64,170~~	~~$57,040~~	~~$51,770~~
Contractor/Employee	$120,000	$120,000	$180,000
~~Recordkeeping/Reporting~~	~~$90,000~~	~~$120,000~~	~~$120,000~~
Totals	**$133,005**	**$135,511**	**$200,521**
Incremental Cost	**NA**	**$2,505**	**$65,011**

CRC = CRF * P

CRC = Capital Recovery Cost (Annualized cost of control over the life of the control)

CRF = Capital recovery Factor P = Capital Investment

CRF = i(1+i)n/(1+i)n-1

i = Annual Interest Rate

n = Economic life of the control

Total Annual Cost (TAC) = Annual Maintenance Cost + Operating Costs + Capital Recovery Cost - Realized Economic Benefit

Cost to Control = TAC / (Targeted Emission Volume Without Control - Targeted Emission Volumn with Control)

Reference Number	**TAC ($)**	**Cost to Control ($/Ton)**	
1	$37,795	**$12,598**	Semi-Annual
2	$100,301	**$41,792**	Quarterly

Does the control have "Economic Reasonableness" and "Technical Practicability"?

The cost to control under the 2010 O&G Guidance ranged from a low of $6,300 per ton of VOCs to an upper bound of $14,700 per ton of V(

Based on the cost range, shown above, semi-annual and quarterly monitoring would be cost-effective for VOC emission control

SEMI- ANNUAL COSTS

IN HOUSE		Cost Description
Camera	$30,100	One IR Camera: $92.25k + 13.39k 6° lens + $8.5k Extended Warranty = 114.14k ($2014) (Amortized @10% and 5 yr) = $30.1k / yr/camera.
		One-Time Cost, includes 100 mm lens and insurance.
Maintenance/yr	$3,000	FLIR maintenance and shipping costs annually
FTE	$120,000	Cost for 1 FTE = $60/hr ($120 K/yr)
Training/employee	$1,000	$5,000/yr over 5 years = $1,000 annual cost
Vehicles	$10,500	Cost for vehicle/year
Mileage Cost	$0.70	$ per mile
Recordkeeping/Reporting	$120,000	1 FTE for Niobrara Program. Contractor and Internal costs are the same for Recordkeeping/Reporting.
Parts/Labor Repair Costs (In House or Contractor)	$310	Average Repair Cost per Leak (Per Mike Genzler 8/19/15) from NW Fetter Pad 15-33-71 Pad LDAR Costs Analysis (9/18/15). See Repair Costs T
Mileage Traveled	7,158	Total miles based on average in-house technician mileage per site = 140 Inspections (70 sites x 2 times/year)
CONTRACTOR		
OGI Contractor Costs for Niobrara	$900	$900/site for OGI

QUARTERLYL COSTS

IN HOUSE		Cost Description
Camera	$30,100	One IR Camera: $92.25k + 13.39k 6° lens + $8.5k Extended Warranty = 114.14k ($2014) (Amortized @10% and 5 yr) = $30.1k / yr/camera.
		One-Time Cost, includes 100 mm lens and insurance.
Maintenance/yr	$3,000	FLIR maintenance and shipping costs annually
FTE	$120,000	Cost for 1 FTE = $60/hr ($120 K/yr)
Training/employee	$1,000	$5,000/yr over 5 years = $1,000 annual cost
Vehicles	$10,500	Cost for vehicle/year
Mileage Cost	$0.70	$ per mile
Recordkeeping/Reporting	$180,000	1.5 FTE for Niobrara Program. Contractor and Internal costs are the same for Recordkeeping/Reporting.
Parts/Labor Repair Costs (In House or Contractor)	$310	Average Repair Cost per Leak (Per Mike Genzler 8/19/15) from NW Fetter Pad 15-33-71 Pad LDAR Costs Analysis (9/18/15). See Repair Costs T
Mileage Traveled	14,316	Total miles based on average in-house technician mileage per site = 280 inspections (70 sites x 4 times/year)
CONTRACTOR		
OGI Contractor Costs for Niobrara	$900.00	$900/site for OGI

MILEAGE ESTIMATE BASIS:

NSPS OOOOa Comment

Vehicle Costs

All costs in $1000's/ Reflect Annual costs	Niobrara Crude Oil Regulatory Costs
Total Mileage Traveled (434 site visits)	22,190
Travel (10.5K/vehicle and fuel/maintenance)	$26.03

ASSUMPTIONS

	Cost	Cost Description
Vehicles	10,500	cost for vehicle/year ^Niobrara includes both FTE and Contractor Mileage
Mileage	0.7	$ per mile

434 total site visits per year = 22,190 miles.

70 x 2 = 140 visits/yr semi-annually / 434 visits/yr *22,190 miles = 7,158 miles semi-annually

70 x 4 = 280 visits/yr quarterly / 434 visits/yr *22,190 miles = 14,316 miles quarterly

Message

From: Lee Fuller [lfuller@ipaa.org]
Sent: 4/2/2018 3:30:06 PM
To: Woods, Clint [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=bc65010f5c2e48f4bc2aa050db50d198-Woods, Clin]; Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; Schwab, Justin [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=eed0f609c0944cc2bbdb05df3a10aadb-Schwab, Jus]
CC: James D. Elliott (jelliott@spilmanlaw.com) [jelliott@spilmanlaw.com]
Subject: Subpart OOOOa
Attachments: Information for IPAA-EPA Meeting - Subpart OOOOa - March 13 2018.pdf

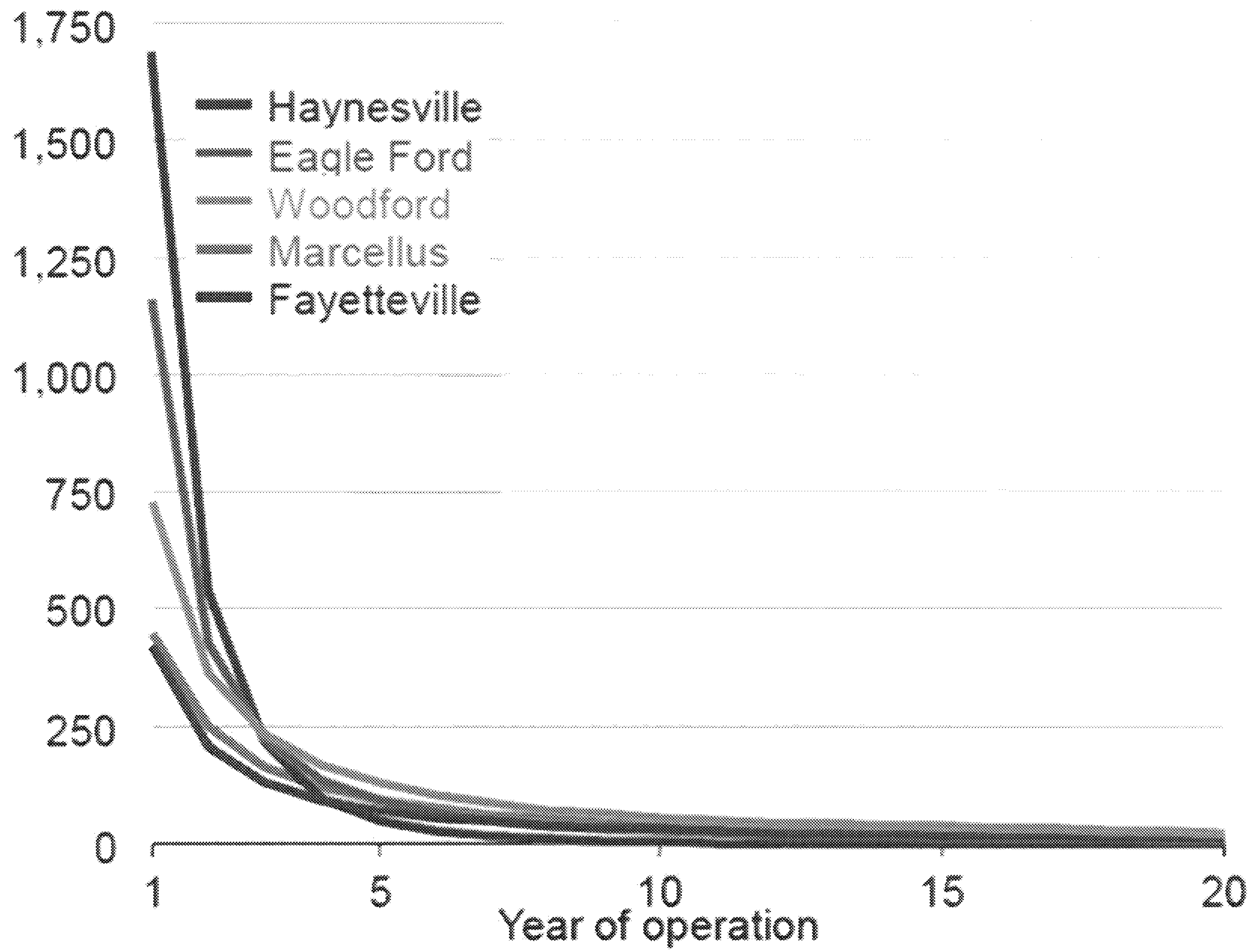
On March 13, IPAA, several state based trade associations and several member companies met with EPA staff at Research Triangle Park to discuss our concerns with the current structure of Subpart OOOOa. While the discussion addressed a number of issues, most of it focused on various definitions that create the scope of the application of the regulations, the fugitive emissions monitoring program and decisions related to the treatment of low production wells. We provided the attached document at the meeting; it is principally addressing the nature of the industry and the role of low production wells including material that responds to published statements by EPA regarding its decision to remove the proposed exclusion of low production wells from the fugitive emissions monitoring program. These include a response to the Environmental Defense Fund allegations that low production wells are “super emitters” and EPA’s use of component counts in justifying the inclusion of low production wells.

Clearly, there are other policy issues that we would like to address, too. I would like to suggest a meeting to bring these before you in the near future.

Thanks,

Lee Fuller

Information for IPAA-EPA Meeting
Subpart OOOOa
March 13, 2018


1,750
1,500
1,250
1,000
750
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250
0
Haynesville
Eagle Ford
Woodford
Marcellus
Fayetteville
1
5
10
15
20
Year of operation

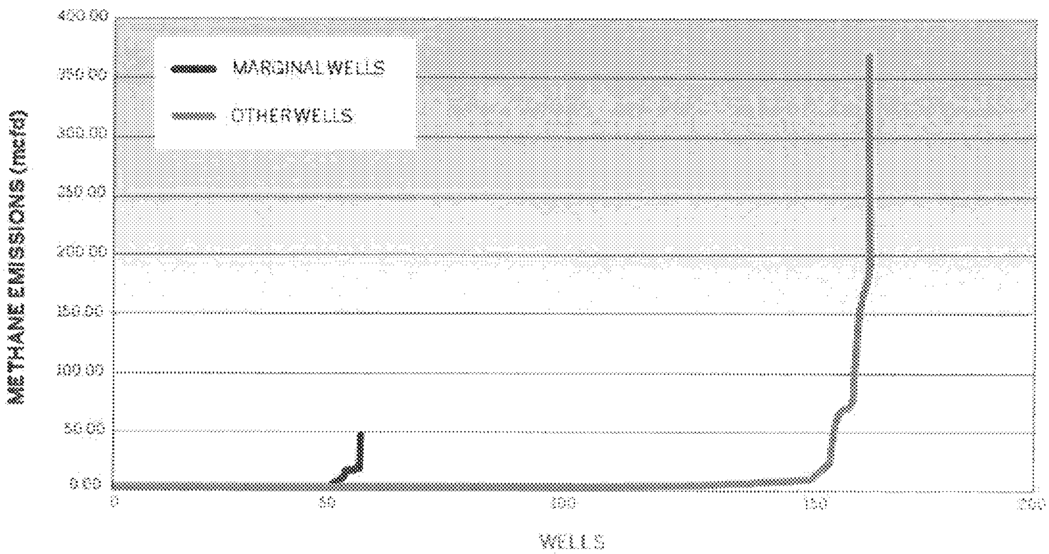
Manipulating Data to Create the Illusion That Low Producing Wells Are "Super-Emitters"

This document addresses data manipulation issues in the environmentalist study submitted to the rulemaking proposal for Subpart OOOOa to distort the role of low producing wells regarding methane emissions. This study was then characterized as the basis for removing the low producing well exclusion for the Subpart OOOOa fugitive emissions program initially proposed by the Environmental Protection Agency (EPA).

Background

Initially, it is important to understand that this study used data from a number of different studies to create its arguments. All of the underlying studies generated their data by driving vehicles with samplers downwind of production sites, hunting for methane plumes. None of them used samples taken on the production site. This creates two issues. First, it measures everything emitted at the site – fugitive emissions and permitted vents. Second, the data are collected over minutes – maybe over an hour – but not over a day. The data in the study are presented as if they were daily emissions but the studies merely scale up hourly estimates. Consequently, an emission that might occur for several hours, but not the full day, would be overstated.

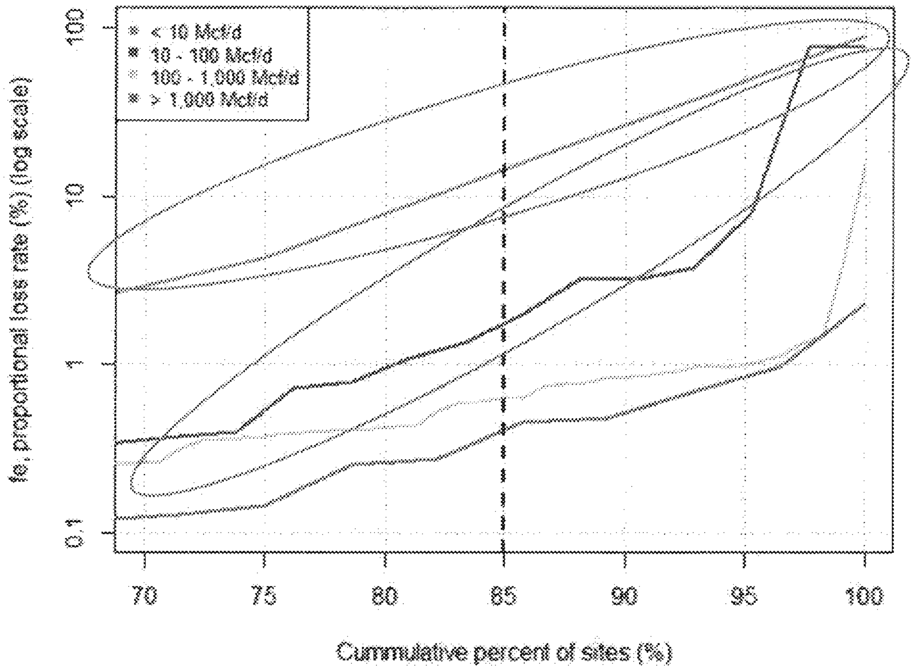
Before turning further to describe the submitted study, it is useful to look at the same data using a direct graph of emissions. In this graph, marginal wells are those with production volumes of 90 mcfd or less.



This graph is consistent with information from other studies showing that a small portion of wells have an emission profile for some reason with high emissions and most wells have really low emissions. Importantly, it also clearly shows that marginal wells – low producing wells in the context of the regulation – have far smaller emissions. But, since this graph is using the same data as the study, it could also be overstating emissions because of scaling short term emissions to a daily amount.

With this background, turning to the presentation of the same material in the study demonstrates how it was manipulated.

Below is the graphic used to present the data. It would suggest that the worst emitting operations – the "super-emitters" – are the smallest wells (the orange line and the blue line, circled in green). Having directly plotted this data, the obvious issue is how such a result can occur.



It is a busy and confusing graph – it's intended to be. The study uses data analysis tricks to create the appearance that marginal wells are "super-emitters".

First, it shows emissions as a percentage of production rather than actual emissions. Thus, one mcf emitted out of ten mcf produced is 10 percent, but 50 mcf emitted out of 1000 mcf produced is 5 percent. As a result, it skews the perception of the data to imply that low producing wells are large emitters when they are not.

Second, its production volumes are really sales volumes, not the amount extracted from the wellhead. Consequently, a "proportional loss rate" of 50 percent would be the calculated loss divided by the volume sold. If the percentage of loss were calculated based on extracted volumes, the 50 percent "proportional loss rate" would drop to 33 percent because the loss would be added to the sales volume to obtain the extracted volume.

Third, it only shows data from the 70th percentile of information. This excludes all of the virtually zero emissions that dominate the data.

Fourth, it uses a logarithmic scale to present the data. One of the reasons to use logarithmic scales is to flatten curves to make them look more like straight lines.

EPA -- Gas Production Sites

Production Equipment	Model Plant Production Equipment Counts	Component Count per Unit of Production Equipment for a "Low Volume" Well				Average Component Count Per Model Plant			
		Valves	Connectors	OELs	PRVs	Valves	Connectors	OELs	PRVs
Gas Well Heads	2	9	37	1	0	19	74	1	0
Separators	2	22	68	4	1	43	137	7	2
Meters/Piping	1	13	48	0	0	13	48	0	0
In-Line Heaters	1	14	65	2	1	14	65	2	1
Dehydrators	1	24	90	2	2	24	90	2	2
	Total:	82	308	9	4	113	414	12	5

Gas Production Site A

Production Equipment	Model Plant Production Equipment Counts	Component Count per Unit of Production Equipment for a "Low Volume" Well				Comments
		Valves	Connectors	OELs	PRVs	
Gas Well Heads	1	6	30	0	0	
Separators	1	1	18	1	1	
Meters/Piping	1	5	5	0	0	
In-Line Heaters	1	3	23	0	0	
Dehydrators	1	7	10	1	0	*Dehydrators are typically not utilized at the well site, but at the downstream sales point.
	Total:	22	86	2	1	

Gas Production Site B

Production Equipment	Model Plant Production Equipment Counts	Component Count per Unit of Production Equipment for a "Low Volume" Well				
		Valves	Connectors	OELs	PRVs	
Gas Well Heads	1	8	12	0	0	
	Total:	8	12	0	0	

Gas Production Site C

Production Equipment	Model Plant Production	Component Count per Unit of Production				
		Valves	Connectors	OELs	PRVs	
Gas Well Heads	1	7	20	0	1	
	Total:	7	20	0	1	

Gas Production Site D

Production Equipment	Model Plant Production Equipment Counts	Component Count per Unit of Production Equipment for a "Low Volume" Well				Average Component Count Per Model Plant			
		Valves	Connectors	OELs	PRVs	Valves	Connectors	OELs	PRVs
Gas Well Heads	2					9	65	0	1
	Total:	0	0	0	0	9	65	0	1

EPA -- Oil Production Sites

Production Equipment	Model Plant Production Equipment Counts	Component Count per Unit of Production Equipment for a "Low Volume" Well				Average Component Count Per Model Plant			
		Valves	Connectors	OELs	PRVs	Valves	Connectors	OELs	PRVs
Oil Well Heads	2	5	18	0	0	10	36	0	0
Separators	1	6	22	0	0	6	22	0	0
Meters/Piping	1	5	14	0	0	5	14	0	0
In-Line Heaters	1	8	32	0	0	8	32	0	0
	Total:	**24**	**86**	**0**	**0**	**29**	**104**	**0**	**0**

Oil Production Site A

Production Equipment	Model Plant Production Equipment Counts	Component Count per Unit of Production Equipment for a "Low Volume" Well				Average Component Count Per Model Plant			
		Valves	Connectors	OELs	PRVs	Valves	Connectors	OELs	PRVs
Oil Well Heads	1	9	10	0	1	9	10	0	1
Separators	0	0	0	0	0	0	0	0	0
Header	1	3	3	0	0	3	3	0	0
In-Line Heaters	0	0	0	0	0	0	0	0	0
	Total:	**12**	**13**	**0**	**1**	**12**	**13**	**0**	**1**

Oil Production Site B

Production Equipment	Model Plant Production Equipment Counts	Component Count per Unit of Production Equipment for a "Low Volume" Well				Average Component Count Per Model Plant			
		Valves	Connectors	OELs	PRVs	Valves	Connectors	OELs	PRVs
Oil Well Heads	1	11	14	0	NA	11	14	0	NA
	Total:	**11**	**14**	**0**	**0**	**11**	**14**	**0**	**0**

Cost of Fugitive Emissions Program on Low Producing Wells

Much of the controversy surrounding the fugitive emissions monitoring program is its enduring application throughout the life of the well. This issue surfaces most significantly as wells decline and become low producing wells. EPA did not assess the cost effectiveness of the fugitive emissions program as it applies to these facilities. Not surprisingly, the impact is significantly different between small and large wells. For the past several years, the Environmental Defense Fund (EDF) has scammed the country and many regulators with an analysis that it developed showing that a variety of methane controls are cost effective. The EDF likes to state that these controls only cost a few cents.

The problem is that the EDF's analysis is flawed and, when the average low producing well produces 22 mcf per day, even a few cents per mcf means a lot. The EDF initially contracted with the ICF International ("ICF") to develop its economic analysis of methane emissions controls. In 2016, ONE Future Inc., contracted with the ICF to revisit its prior work using more realistic assumptions.[1] One key assumption – an assumption that is also problematic with the EPA's economic analysis for Subparts OOOO and OOOOa – is the value of methane used in the analyses. The EDF and the EPA use a value of $4.00/mcf. This is not a realistic value. The ONE Future analysis used $3.00/mcf, which is close to the current national wellhead price for natural gas but still conservative. Equally important, it reflected that a producer does not receive this amount due to royalties and fees that are about 25% of the wellhead price and therefore reduces the net to the producer to about $2.25/mcf. However, even the ONE Future/ICF report does not attempt to distinguish the cost effectiveness of controls based on size of operation.

However, it can be done. The ONE Future/ICF study developed information on the cost of a fugitive emissions leak detection and repair (LDAR) that approximates the Subpart OOOOa biannual testing program. It concluded that the annual cost for the program is $3,436.[2]

There are little data on the emissions from low producing wells. However, in the EPA's April 2012 Technical Support Document for its NSPS,[3] it created a model plant well pad for one well that estimates methane emissions at 0.330 tons/year.[4] This translates to 16 mcf/year.

The ICF analysis uses an estimate that 50% of these emissions would be reduced by the LDAR program. Using the more realistic product prices, this recovery adds about $17.50 to the income of the well and reduces the net cost to about $3,418/year. It is noteworthy to point out that even this small recovery may overstate the amount. Field experience with state fugitive emissions programs indicates that after the first examination of a facility and the initiation of operation and maintenance programs on equipment, subsequent LDAR reviews find far fewer leaks to repair.

---

[1] *Economic Analysis of Methane Emission Reduction Potential from Natural Gas Systems*, ICF International, May 2016.

[2] As noted and set forth in their own cost analyses below, the Independent Producers submit that this agency estimate is low.

[3] *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Background Supplemental Technical Support Document for the Final New Source Performance Standards*, EPA, April 2012.

[4] Ibid, Appendix C.

Additionally, recent American Petroleum Institute (API) efforts have shown that the EPA's assumptions on initial equipment leaks are higher than actual experience.

The larger question is what impact does this have on a low producing well. Using the ICF assumptions, the average low producing well (22 mcf per day) would receive daily income of $49.50 ($18,000 per year).

It is difficult to determine operating costs but the Energy Information Administration ("EIA") released a report in March 2016, *Trends in U.S. Oil and Natural Gas Upstream Costs*, which assessed a wide range of costs and looked at several production areas. One of its evaluations addressed operating costs in the Marcellus play – the world-scale natural gas play in the northeastern states. The report estimated that Marcellus operating costs range from $12.36/BOE to $29.60/BOE. Using the standard 1 BOE = 6 mcf conversion, it produces operating costs ranging from $2.06/mcf to $4.93/mcf. Applying these costs to the average low producing well results in a daily cost range of $45.32 to $108.46.

Consequently, the average low producing well would have to manage its finances in a range from a daily income of $4.18 to a loss of $58.95. In this difficult financial situation, the application of the EPA LDAR program is a more significant factor than EPA has presumed in its analysis. The daily cost of its program would be $9.36 – after taking into account methane recovery. For a low producing well, this small change would drive the well into a net loss ranging from about $5.00/day to $68.00/day.

Clearly, there are many factors that come into play in this analysis – price of natural gas, cost of the LDAR program, operating costs. The fundamental point is that an LDAR program that *may* be justified for large producing wells will have a very different impact on small ones. The EPA should develop a methodology that reflects these differences and it has not.

Message

From: Carpenter, Thomas [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=C286CF1692FA46DC9636A7C49C0925B8-CARPENTER, THOMAS]
Sent: 2/26/2018 5:05:38 PM
To: Nancy_Beck@americanchemistry.com [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=2922d8f69dd84e5386dac0de980c51e5-Nancy_Beck@americanchemistry.com]; Schwab, Justin [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=eed0f609c0944cc2bbdb05df3a10aadb-Schwab, Jus]
CC: Brennan, Thomas [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=78caa4c8d91743c887c1bb5dc8cdb369-Thomas Brennan]
Subject: hiring foreign nationals as SGEs
Attachments: SGE Hiring Foreign Nationals 20170926.docx

Nancy and Justin

The attached document and email below summarize the steps to hiring are foreign nationals as SGEs. SAB staff worked with OGC and OARM staff to draft the summary and presented the attached document to the DFO network in September 2017. The summary has the OGC and HR contacts we worked with to develop the options.

The SAB is in the process of bringing on a SGE that is a permanent resident with green card and UK citizenship. It is the first time we have used the process with HR staff.

Best
Tom Carpenter

Thomas Carpenter
Designated Federal Officer / Sr. Biologist
US EPA Science Advisory Board, MC 1400R
1200 Pennsylvania Avenue, NW
Washington DC 20460
ph 202 564 4885 Fax 202 565 2098

From: Hanlon, Edward
Sent: Monday, August 14, 2017 12:46 PM
To: Subject: further updated final version hiring foreign nationals as SGEs

Hi all,

FYI, Khanna, Sue, Tom A. and I talked with David Guerrero of OGC last Thursday afternoon on hiring foreign nationals as SGEs. David is an OGC labor attorney. Jim McCleary was also on the call.

During our teleconference with David, we discussed the two scenarios for hiring foreign nationals as SGEs: 1) those who live in the US and 2) those who live outside of the US. Based on that discussion, we've updated our response to nominees regarding hiring foreign nationals as SGEs. See the attached updated emails to folks covering the two scenarios. In quick summary of our discussion and the attached emails is noted below.

For foreign nationals who live in the US, EPA is prohibited by law from using appropriated funds to compensate a U.S. Government employee, including SGEs, who work in the United States unless the employee is a U.S. citizen, or is a person who is lawfully admitted to the United States for permanent residence and is seeking U.S. citizenship within six months of being eligible to do so. To allow us to determine their eligibility for compensable service on EPA FACA Committees, we would ask foreign nationals who live in the US to please confirm whether they are a lawfully admitted permanent resident and have applied for U.S. citizenship.

If foreign nationals who live in the US are willing to serve as an SGE on EPA FACA Committees without compensation, we could hire such foreign nationals who live in the US if they are either: a) a lawful permanent resident (i.e., a green card holder); or b) a person who has already received authorization to work in the United States from the U.S. Citizenship and Immigration Services. If they do not have such authorization, a person must be willing to apply for and must receive such authorization in order to serve as an SGE on an EPA FACA Committee.

For foreign nationals who live outside the US, they can serve as an SGE for compensable service on EPA FACA Committees if they are either: a) a lawful permanent resident (i.e., a green card holder); or b) a person who has already received authorization to work in the United States from the U.S. Citizenship and Immigration Services as long as their duty station is outside the US. If they do not have such authorization, a person must be willing to apply for and must receive such authorization in order to serve as an SGE on the EPA FACA Committee.

Hiring Foreign Nationals to Serve as Special Government Employees
9/26/17 Draft

Foreign National Serving as SGE on EPA FACA Committee With Compensation

Foreign Nationals Who Live or Work in U.S. And Will Perform Some or All SGE Duties Within U.S. (e.g., To Attend FACA Meeting) With Compensation

Can hire Foreign Nationals as SGEs and compensate them, if:

- The Foreign National:
  - Is lawfully admitted to the United States for permanent residence (i.e., is a 'green card holder'); and
  - Is seeking U.S. citizenship; and
  - *Is within six months of being eligible to become a U.S. citizen or submits an affidavit reflecting his/her intent to apply for citizenship when eligible to do so; and
- DFO works with EPA's Office of Administration and Resources Management (OARM) (e.g., Kelly Glazier) to conduct a background/security check on the Foreign National.

**Note: A non-citizen green card holder would typically have to wait five years to apply for citizenship once he/she has obtained permanent resident status. However, an agency could employ a permanent resident during that five-year waiting period if the permanent resident submits an affidavit reflecting his/her intent to apply for citizenship when eligible to do so. David Guerrero in OGC can provide DFO with a copy of a sample affidavit.*

Foreign Nationals Who Do Not Live or Work in U.S., Will Serve as an SGE With Compensation, And Will Not Perform Any SGE Duties Within U.S. (e.g., Will Communicate only via Email and Teleconference)

Can hire Foreign Nationals as SGEs and compensate them, if:

- DFO works with EPA's Office of Human Resources (OHR) (e.g., Loretta Hunt) to establish a post of duty (i.e., duty station) and to confirm that this duty station is not in the U.S.; and
- DFO works with EPA's Office of Administration and Resources Management (OARM) (e.g., Kelly Glazier) to conduct a background/security check on the Foreign National.

Foreign Nationals Who Do Not Live or Work in U.S., Will Serve as an SGE With Compensation, And Will Perform Some or All SGE Duties Within U.S. (e.g., To Attend FACA Meeting)

Can hire Foreign Nationals as SGEs and compensate them, if:

- The Foreign National receives a visa for a work permit (i.e., a work authorization visa) to allow them to be compensated by the U.S. for the work they perform inside of the U.S.; and
- *DFO works with EPA's Office of Human Resources (OHR) (e.g., Loretta Hunt) to establish a post of duty (i.e., duty station) and to confirm that this duty station is not in the U.S.; and
- DFO works with EPA's Office of Administration and Resources Management (OARM) (e.g., Kelly Glazier) to conduct a background/security check on the Foreign National.

**Note: OHR may decide that performing such compensated work in the U.S. violates Appropriations Act restrictions, even if Foreign National's duty station is outside the U.S.*

Foreign National Serving as SGE on EPA FACA Committee Without Compensation

<table>
<tr><td>

Foreign Nationals Who Live or Work in U.S., Will Serve as an SGE Without Compensation, And Will Perform Some or All SGE Duties Within U.S. (e.g., To Attend FACA Meeting)

Can hire Foreign Nationals as SGEs without compensating them*, if:

- The Foreign National:
  - Is lawfully admitted to the United States for permanent residence (i.e., is a 'green card holder'); or
  - Holds a visa for a work permit (i.e., a work authorization visa) to allow them to work inside of the U.S.; or
  - Is willing to apply for a visa for a work permit (i.e., a work authorization visa) to allow them to work inside of the U.S., and receives such authorization before beginning work as an SGE; and
- DFO works with EPA's Office of Administration and Resources Management (OARM) (e.g., Kelly Glazier) to conduct a background/security check on the Foreign National.

**Note: 'Without Compensation' means EPA will not pay an hourly wage for services from the Foreign National as an SGE; however, EPA may pay travel expenses (e.g., airfare; taxi; per diem) for such service without compensation.*

</td></tr>
<tr><td>

Foreign Nationals Who Do Not Live or Work in U.S., Will Serve as an SGE Without Compensation, And Will Not Perform Any SGE Duties Within U.S. (e.g., Will Communicate only via Email and Teleconference)

Can hire Foreign Nationals as SGEs without compensating them*, if:

- DFO works with EPA's Office of Human Resources (OHR) (e.g., Loretta Hunt) to establish a post of duty (i.e., duty station) and to confirm that this duty station is not in the U.S.; and
- DFO works with EPA's Office of Administration and Resources Management (OARM) (e.g., Kelly Glazier) to conduct a background/security check on the Foreign National.

**Note: 'Without Compensation' means EPA will not pay an hourly wage for services from the Foreign National as an SGE; however, EPA may pay travel expenses (e.g., airfare; taxi; per diem) for such service without compensation.*

</td></tr>
</table>

Message

From:	Woods, Clint [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=BC65010F5C2E48F4BC2AA050DB50D198-WOODS, CLIN]
Sent:	4/4/2018 10:12:35 PM
To:	Lee Fuller [lfuller@ipaa.org]; Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; Schwab, Justin [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=eed0f609c0944cc2bbdb05df3a10aadb-Schwab, Jus]
CC:	James D. Elliott (jelliott@spilmanlaw.com) [jelliott@spilmanlaw.com]
Subject:	RE: Subpart OOOOa

Lee,

Thanks so much for your email, and apologies for the delayed follow up. We are taking a closer look at the attachment, and would welcome the chance to discuss further when convenient. I've copied Emily Atkinson, who may be able to help us in finding a good date/time.

Clint Woods
Deputy Assistant Administrator
Office of Air and Radiation, U.S. EPA
202.564.6562

From: Lee Fuller [mailto:lfuller@ipaa.org]
Sent: Monday, April 2, 2018 11:30 AM
To: Woods, Clint <woods.clint@epa.gov>; Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>; Schwab, Justin <Schwab.Justin@epa.gov>
Cc: James D. Elliott (jelliott@spilmanlaw.com) <jelliott@spilmanlaw.com>
Subject: Subpart OOOOa

On March 13, IPAA, several state based trade associations and several member companies met with EPA staff at Research Triangle Park to discuss our concerns with the current structure of Subpart OOOOa. While the discussion addressed a number of issues, most of it focused on various definitions that create the scope of the application of the regulations, the fugitive emissions monitoring program and decisions related to the treatment of low production wells. We provided the attached document at the meeting; it is principally addressing the nature of the industry and the role of low production wells including material that responds to published statements by EPA regarding its decision to remove the proposed exclusion of low production wells from the fugitive emissions monitoring program. These include a response to the Environmental Defense Fund allegations that low production wells are "super emitters" and EPA's use of component counts in justifying the inclusion of low production wells.

Clearly, there are other policy issues that we would like to address, too. I would like to suggest a meeting to bring these before you in the near future.

Thanks,

Lee Fuller

From: Lee Fuller [lfuller@ipaa.org]
Sent: 10/3/2017 9:04:30 PM
To: Schwab, Justin [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=eed0f609c0944cc2bbdb05df3a10aadb-Schwab, Jus]
CC: James D. Elliott (jelliott@spilmanlaw.com) [jelliott@spilmanlaw.com]; Kern, Gretchen (Gretchen.Kern@pxd.com) [Gretchen.Kern@pxd.com]; Schaaff, Lesley [lschaaff@hess.com]; Susan Ginsberg [sginsberg@ipaa.org]; Samantha McDonald [SMcDonald@ipaa.org]
Subject: IPAA Meeting Follow Up
Attachments: IPAA Comments -- Evaluating Existing Regulations -- Docket ID EPA-HQ-OA-2017-019 05-15-2017.pdf; IPAA-AXPC Comments on 9-18-2015 Oil and Gas Proposals.pdf; IPAA-AXPC-Coalition Petition for Reconsideration of Subpart OOOOa.pdf; Manipulating Data to Create the Illusion That Low Producing Wells Are Super-Emitters.pdf; Texas Environmental Law Meeting -- Environmental Issues in the Oil Patch -- 08-2017.pdf

Flag: Follow up

Justin,

We appreciated meeting with you and Mandy yesterday regarding air emissions management of oil and natural gas production operations. I have attached several documents that expand on the nature of the issues that we discussed. There will be some repetition because the issues have been addressed several times.

They include:

1. IPAA comments to EPA on Evaluating Existing Regulations
2. IPAA-AXPC Comments on the Subpart OOOOa, CTG and Source Determination proposals in 2015
3. IPAA-AXPC-Coalition Petition for Reconsideration of Subpart OOOOa – includes the low production well issue among others
4. An assessment of the data manipulation in the study that EPA used to eliminate the low production well exclusion from Subpart OOOOa
5. A publication that I prepared for a meeting on environmental issues in the oil patch that uses the development of the air emissions regulations as its focus beginning with Subpart OOOO.

Thanks again for the opportunity to meet on these issues.

Lee Fuller

INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

Evaluation of Existing Regulations

Docket ID: EPA-HQ-OA-2017-0190

May 15, 2017

These comments are filed on behalf of the Independent Petroleum Association of America (IPAA), the American Association of Professional Landmen (AAPL), the American Exploration and Production Council (AXPC), the Association of Energy Service Companies (AESC), the Domestic Energy Producers Alliance (DEPA), the International Association of Drilling Contractors (IADC), the International Association of Geophysical Contractors (IAGC), the National Stripper Well Association (NSWA), the Petroleum Equipment & Services Association (PESA), and the following organizations:

Arkansas Independent Producers and Royalty Owners Association
California Independent Petroleum Association
Coalbed Methane Association of Alabama
Colorado Oil & Gas Association
East Texas Producers & Royalty Owners Association
Eastern Kansas Oil & Gas Association
Florida Independent Petroleum Association
Idaho Petroleum Council
Illinois Oil & Gas Association
Independent Oil & Gas Association of New York
Independent Oil & Gas Association of West Virginia
Independent Oil Producers' Agency
Independent Oil Producers Association Tri-State
Independent Petroleum Association of New Mexico
Indiana Oil & Gas Association
Kansas Independent Oil & Gas Association
Kentucky Oil & Gas Association
Louisiana Oil & Gas Association
Michigan Oil & Gas Association
Mississippi Independent Producers & Royalty Association
Montana Petroleum Association
National Association of Royalty Owners
Nebraska Independent Oil & Gas Association
New Mexico Oil & Gas Association
New York State Oil Producers Association
North Dakota Petroleum Council
Northern Montana Oil and Gas Association
Ohio Oil & Gas Association
Oklahoma Independent Petroleum Association

Panhandle Producers & Royalty Owners Association
Pennsylvania Independent Oil & Gas Association
Permian Basin Petroleum Association
Petroleum Association of Wyoming
Southeastern Ohio Oil & Gas Association
Tennessee Oil & Gas Association
Texas Alliance of Energy Producers
Texas Oil and Gas Association
Texas Independent Producers and Royalty Owners Association
Utah Petroleum Association
Virginia Oil and Gas Association
West Slope Colorado Oil & Gas Association
West Virginia Oil and Natural Gas Association

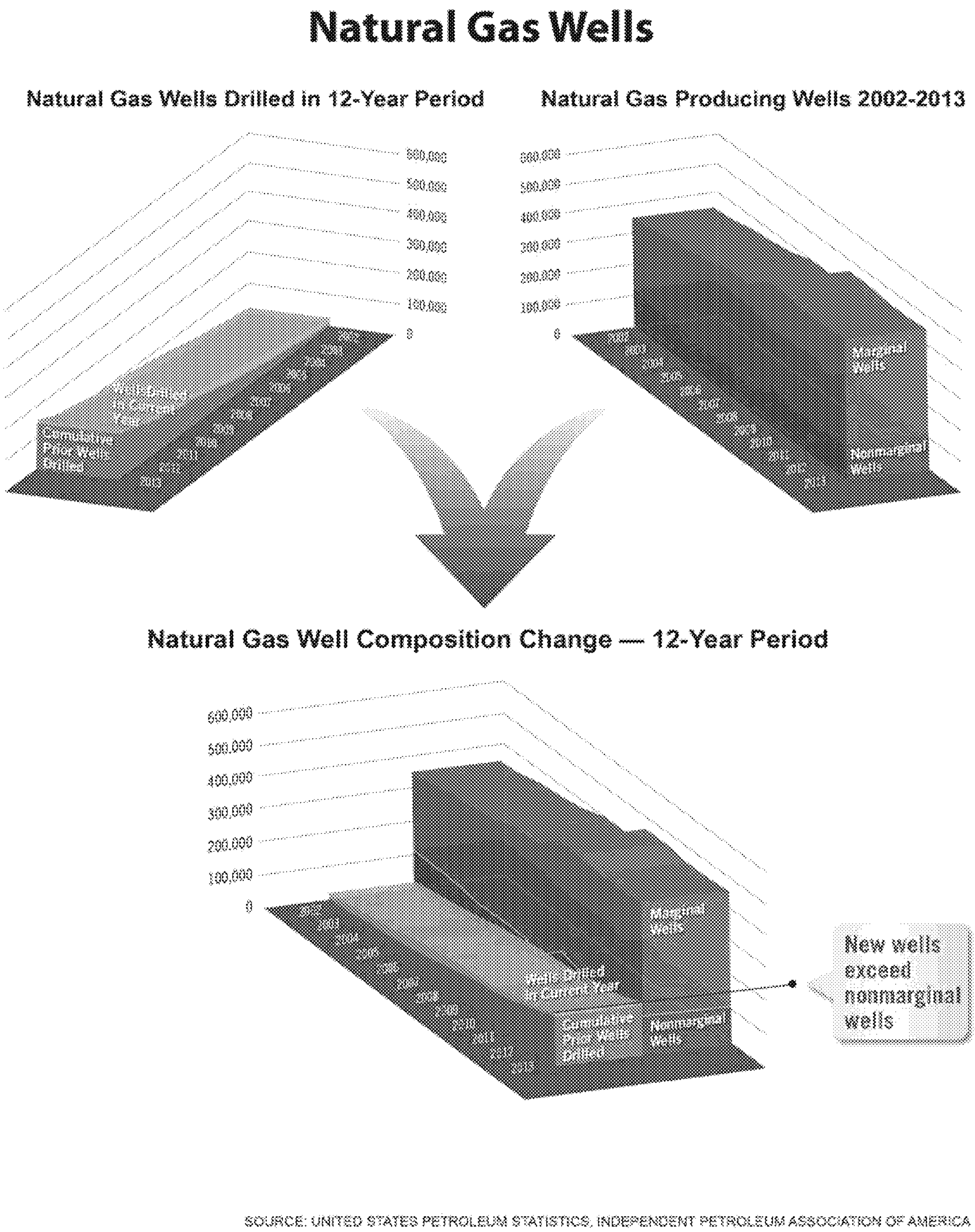
Collectively, these groups represent the thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts, that are significantly affected by Environmental Protection Agency (EPA) regulatory actions. Independent producers drill about 90 percent of American oil and gas wells, produce 54 percent of American oil and produce 85 percent of American natural gas.

In addition to the specific comments made herein, we support those comments submitted separately by the participants in these comments.

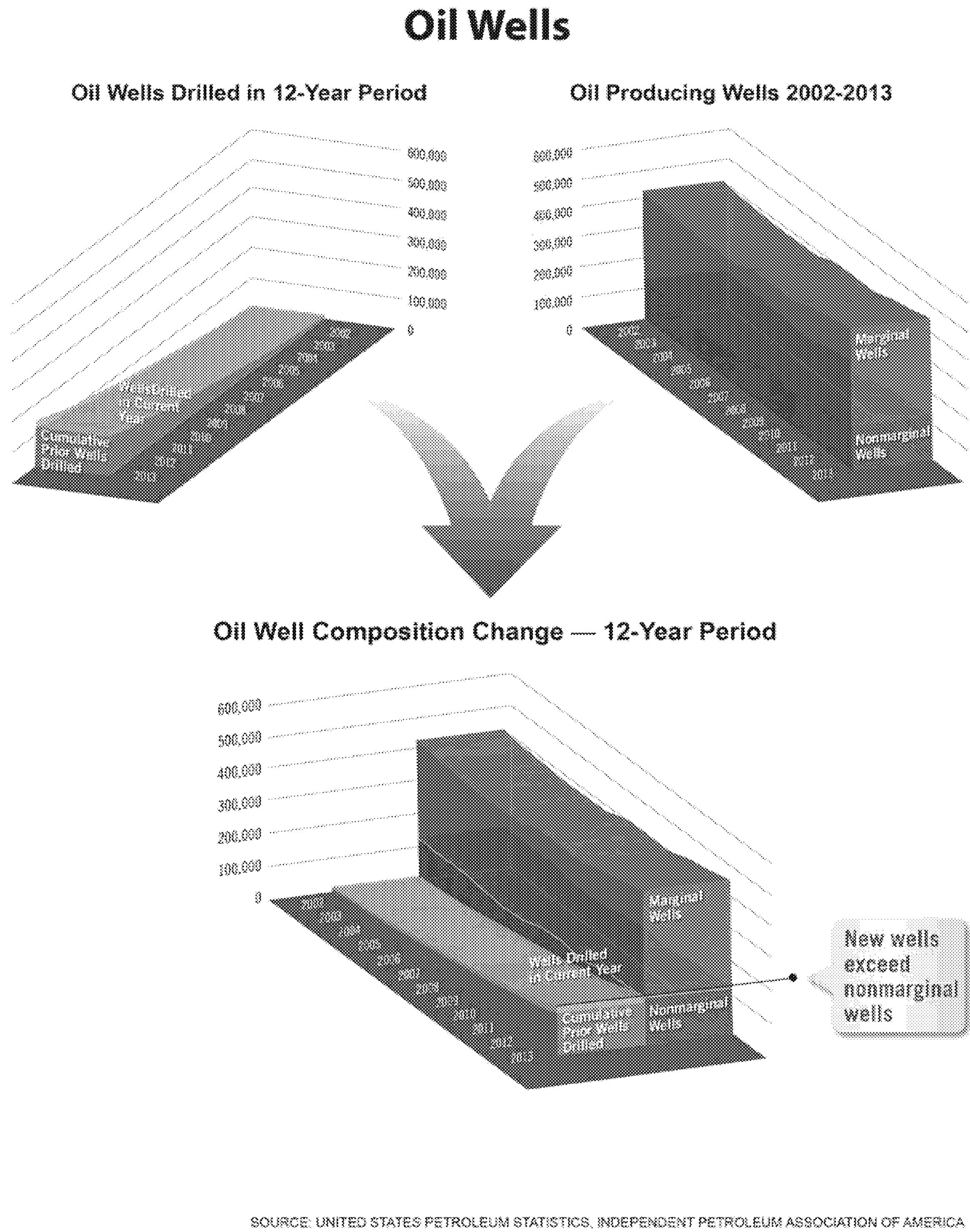
American oil and natural gas producers recognize and support the importance of managing the environment. Overwhelmingly, they live in the communities where they produce. At the same time, oil and natural gas extraction is a primary industry. It involves breaking through layers of hard rock to reach oil and natural gas producing zones. It has over the past decades become more sophisticated through the use of highly technical skills. In particular, the development of horizontal drilling in combination with hydraulic fracturing has opened access to unconventional shale formations and changed the framework of American energy supply. But, it is also an industry with hundreds of thousands of legacy conventional wells. It operates in all types of geographical areas – arid to swamp to offshore, freezing to sweltering, rural to urban. Each of these can create different environmental management challenges.

Independent producers believe that air emissions can be managed, including methane, through cost effective Volatile Organic Compound technologies, that produced water can be used, reused, treated and discharged safely, that drilling fluids will continue to be well controlled. At the heart of these actions are state regulators who understand the differing circumstances under their control and regulate accordingly. Correspondingly, EPA needs to play a distant role that recognizes the expertise and commitment of the state regulators who – like producers – live in these producing areas.

To put these comments in context, it is important to understand the nature of the American oil and natural gas industry. Oil and natural gas wells naturally deplete over time. That is, following high volumes of initial production, volumes begin to decline. Ultimately, the rate of decline slows – typically when the well production reaches marginal well amounts. Correspondingly, the industry is a "food chain" industry. As large companies want more capital, they sell their lower producing properties to smaller companies. This explains in large measure why small businesses are the primary owners of marginal wells. The following graphic shows how depletion affects the mix of natural gas well operations:



The same dynamics occur for oil wells:



These comments will address several EPA regulatory actions that can adversely affect independent oil and natural gas producers.

Additionally, these comments will address issues raised in oral comments to the Small Business stakeholder public meeting on April 25, 2017. IPAA is a federally focused trade association. Its membership spans the scope of America's independent oil and natural gas producers. The median size of an IPAA member firm is 12 full time employees. Consequently, IPAA has a strong small business component. The other participants in these comments have similar small business components. These small businesses are the primary operators of America's marginal wells. A marginal oil well produces 15 barrels per day or less; a marginal natural gas well produces 90 mcfd or less. However, the average marginal oil well produces about 2.7 barrels per day and the average marginal natural gas well produces about 22 mcfd. Approximately 80 percent of US oil wells are marginal wells. About two-thirds of American natural gas wells are marginal wells. However, collectively they are a significant component of American production generating between 10 and 20 percent of US oil production and between 12 and 13 percent of US natural gas production.

This juxtaposition of small businesses operating marginal wells creates the consequence that EPA regulations that do not recognize their impact on marginal wells result in excessive impacts on these small businesses.

Regulatory Framework Objectives

Independent producers seek a predictable, cost effective regulatory system.

United States environmental regulations are a mix of federal and state regulations. The primary federal environmental laws – the Clean Air Act, the Clean Water Act, the Safe Drinking Water Act and the Resource Conservation and Recovery Act – hinge on balanced federal and state roles. The federal government's role is principally creating national standards, authorizing state management of federal law, stewarding state regulatory actions, addressing interstate and international issues and funding for research and state support. Correspondingly, states develop and manage direct regulatory programs designed to meet national standards and reflect their differing local circumstances. In evaluating its existing regulatory actions, EPA needs to revisit these balances and assure that the states and regulated community are protected against aggressive political efforts to federalize regulations – particularly, from IPAA's perspective, with regard to oil and natural gas production.

More specifically, EPA needs to include a significant state delegation initiative. Most of the actions related to state delegation occurred within the first few years following legislative enactment. Now, decades after the last revisions to these major laws, the state delegation process needs to be rejuvenated; states need encouragement, facilitation and funding. Failure to effectively delegate authority opens opportunities for federal incursion into regulatory activities that are intended to be under state management. And, it places the regulated community in a position where double regulation – state and federal – unnecessarily compounds their daily operations.

For oil and natural gas production, federal regulations should be targeted. For example, federal air emissions regulations should be Volatile Organic Compound (VOC) based. EPA needs to recognize the variability of oil and natural gas production operations and ownership. It needs to define low production wells and assure that any federal regulation is specifically analyzed for them; these low production wells should be excluded from regulation where that is feasible.

EPA needs to assure that federal technology determinations are based on analyses that are designed for assessing regulations and are scientifically sound. Recent federal regulatory actions have utilize analyses that were never developed for regulatory design purposes. Consequently, EPA extrapolated information to justify its regulatory actions beyond the validity of the underlying data – an issue that is particularly problematic with regard to low production wells. In developing new regulations, EPA needs to devise procedures to use federal resources for analyses – designing programs and assuring data quality and focus for regulation.

EPA needs to thoroughly review and revise its federal enforcement process. It needs to create an enforcement program that treats the regulated community with fairness, respect and dignity. It needs to eliminate the use of excessive threatening tactics, egregious fine proposals and enforcement to compel regulation where EPA has no authority.

AIR REGULATIONS

Oil and Natural Gas Production Regulations

Over the past several years, EPA has created several Clean Air Act (CAA) regulatory actions regarding oil and natural gas production operations. These include: New Source Performance Standards (NSPS) Subpart OOOO and Subpart OOOOa and Control Techniques Guidelines (CTG).

In 2012, EPA promulgated NSPS Subpart OOOO creating VOC regulations on several oil and natural gas production emissions sources – reduced emissions completion (REC) of fractured natural gas wells, pneumatic controllers and storage vessels. In 2016, EPA promulgated NSPS Subpart OOOOa creating methane regulations on additional oil and natural gas production emissions sources – REC for fractured oil wells, pneumatic pumps and fugitive emissions – and converting Subpart OOOO to a methane regulation. In 2016, EPA finalized a CTG for existing sources of oil and natural gas production facilities in Ozone National Ambient Air Quality Standards (NAAQS) nonattainment areas. In 2016, EPA announced its intent to initiate a methane based nationwide existing source regulatory program and started an Information Collection Request (ICR) to collect information for that purpose.

In 2017, EPA terminated the ICR. The Trump Administration announced its intent to revisit the Subparts OOOO and OOOOa regulations and suspended the Subpart OOOOa fugitive emissions requirements pending action on a petition for reconsideration.

This mix of regulations resulted first in the case of Subpart OOOO from a consent decree and subsequently from the Obama Administration Climate Action Plan. Taken together, they present – in their current form – excessive regulatory burdens without attendant environmental benefits. The reasons differ but are primarily related to the shift in the regulatory framework to a methane basis as a pathway to federalizing oil and natural gas production regulation. Importantly, for oil and natural gas production, controlling VOC also controls methane because they are emitted together and, therefore, reduced together.

When the VOC Subpart OOOO regulations were finalized, they were largely based on technology that had been utilized as in EPA's voluntary Gas STAR program. This voluntary program was highly effective in reducing emissions long before the regulations were created because many of the new large fractured natural gas wells were using these technologies. Nevertheless, as EPA moved from a voluntary program to regulations, it created adverse consequences because in defining terms it captured operations that were not appropriate for the technology and it created opportunities for abusive enforcement actions.

These issues were dramatically expanded when Subpart OOOOa was finalized. First, shifting the regulation target to methane did not improve emissions reductions from new sources, but it did open a little used CAA pathway – Section 111(d) – to create nationwide existing source regulations. The approach would principally target older wells since more recent ones either used Gas STAR voluntary technologies or are permitted under Subpart OOOO. Most of these older wells will be low production wells.

Second, the fugitive emissions component of Subpart OOOOa goes well beyond widely accepted technology. NSPS regulations should be based on the best system of emissions reductions (BSER) "…which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." The evolution of fugitive emissions regulations for oil and natural gas production is recent. Emissions analyses in the past several years identified that production emissions are characterized by a few pieces of equipment with large emissions ("fat tails") rather than a broad array of sources. States have been developing fugitive emissions programs in recent years. None of these use the approach in the Subpart OOOOa regulations. Consequently, it is illogical to suggest that the Subpart OOOOa requirements conform to the BSER standard.

Third, a particular problem with the fugitive emissions regulations relates to their cost effectiveness – a BSER issue – over the life of the facility. While other components of Subparts OOOO and OOOOa are capital mandates – specific equipment being required – the fugitive emissions provisions are enduring operating costs that apply for the life of the well. Consequently, as well production declines, the cost effectiveness of the fugitive emission program changes and becomes more and more burdensome. The initial Subpart OOOOa proposal would have excluded low production wells from the requirements, but this exclusion was eliminated in the final regulation based on a specious analysis from Keep It in the Ground environmental activists.

The CAA provides for the development of CTG for existing sources of criteria pollutants in nonattainment areas. One of the most common uses relates to Ozone NAAQS nonattainment areas where the targeted criteria pollutants are VOC and/or nitrogen oxides. While EPA was in the process of proposing Subpart OOOOa and initiating its drive for a nationwide methane existing source regulations, it also proposed VOC CTG for existing oil and natural gas production operations in ozone nonattainment areas.

VOC CTG apply in Moderate, Serious, Severe and Extreme ozone nonattainment areas. State Implementation Plans (SIPs) must include regulations that have been published as CTG as a part of their Reasonably Available Control Measures (RACM) or they have to develop alternative regulations to obtain the predicted VOC reductions from the CTG. While the CAA provides for minimum source sizes that must be regulated in these Ozone nonattainment areas – ranging from

100 tons/year to 10 tons/year depending on the classification – these source size limits do not apply when a CTG regulates smaller facilities.

Moreover, the oil and natural gas production CTG is essentially a regulatory mix that applies the NSPS technologies to existing sources. However, those BSER requirements are based on their application to new or modified facilities. The technology standard for CTG – which are required for existing facilities – is Reasonably Available Control Technology (RACT). BSER and RACT are not the same; RACT must consider the cost effectiveness of its technologies in retrofitting existing sources. The CTG as finalized essentially require replacing existing equipment. EPA's development of the CTG should have been primarily analyzing its impact on low production operations. As earlier graphics showed, after about a decade, wells drilled during that decade will be all of the non-low production wells. This means that they will be comprised of the NSPS technology requirements – in this case, pneumatic controllers and storage vessel controls. Consequently, the predominant cost burden of the CTG will be borne by the legacy wells that are the small producers. Yet, EPA made no effort to assess RACT between these clearly different components of the array of producers and to assess the cost effectiveness of that assessment.

Both the BSER determination in Subparts OOOO and OOOOa and the RACT decisions in the CTG development raise significant questions about the nature of EPA's technology evaluations. The CAA tasks EPA with the responsibility to make critical, long lasting decisions regarding technologies that have extensive national implications. BSER becomes the national standard for new sources – requirements that must be met on every new and modified source. RACT becomes a mandate that states must implement in nonattainment areas or obtain comparable reductions from other sources – a politically unlikely result.

If the experience in these regulations is a fair indicator, EPA faces an enormous challenge to assure that it properly acquires and assesses technology. While EPA lists many studies in its justification of both the Subpart OOOO and OOOOa regulations and the CTG, these studies fall well short of the materials that are needed for regulatory development. Realistically, the better studies were broadly designed to merely understand the nature of oil and natural gas production emissions. They have been useful in establishing that the emissions patterns for these operations are characterized by a few "fat tails" – failed or poorly maintained equipment – rather than broad systemic losses. But, they were never crafted to be used for regulatory development. Nevertheless, EPA has used them for that purpose. In Subpart OOOO, the failure of this approach was largely suppressed because the NSPS technologies were ones that were in use in the EPA Gas STAR voluntary program. But, their use in Subpart OOOOa for the fugitive emissions component is illustrative.

The regulation of fugitive emissions primarily relies on an excessively costly optical gas imaging (OGI) leak detection and repair (LDAR) program. The LDAR requirements were wholly inappropriate. NSPS is intended to use a nationally applicable, adequately demonstrated BSER. Multiple states have been creating fugitive emissions programs. All are different; none use the approach in Subpart OOOOa. EPA's drive to embrace its program based on the paltry analytical information it had falls well short of a BSER determination.

Compounding the lack of sound, federally sanctioned studies, EPA also chose to rely on wholly flawed, advocacy studies in its actions. When EPA proposed its LDAR program, it created an exclusion for low producing – marginal – wells. Importantly, producers do not intentionally drill marginal wells, but all wells eventually decline and become marginal. By creating the low producing well exclusion, small businesses would not have been subjected the demanding costs of LDAR. However, in the final rule, EPA removed the low producing well exclusion. Sadly, this is the precise intent of the Keep It in the Ground environmental movement that dominated the EPA decision to remove the low producing well exclusion. This decision was principally based on a specious study that creates the impression that low producing wells are large emitters. Its flaws are described in Appendix 1.

More broadly, it calls into question whether EPA can fulfill its statutory CAA responsibilities relying on studies that it neither designs nor funds. Clearly, in this instance, the failure to have a well-designed framework of information failed to produce well designed regulations. Given the clear political pressure that was driving the Subpart OOOOa and CTG requirements, EPA failed to stand up to the pressure and insist on sound and robust regulatory studies to meet its responsibilities.

A counterpoint to these concerns occurred on April 26, 2017, when an EPA study was published. The study addressed emissions from pneumatic controllers in oil and natural gas operations. Its significance remains to be seen, but it presents some of the issues described above in an interesting context. At its heart, the study – conducted by EPA experts – concludes that EPA has been overestimating emissions from pneumatic controllers. In fact, EPA researchers found methane emissions from intermittent bleed devices were 97 percent lower than the standard emission factor for intermittent pneumatic control devices EPA uses for estimates in its Greenhouse Gas Inventory (GHGI). This is relevant on a national scale considering EPA's latest GHGI reported 45 percent of oil and gas system methane emissions in 2015 were attributable to pneumatic controllers. The researchers acknowledge the significance of this finding by noting pneumatic devices are the "most significant sources of CH4 in ONG[1] production field operations."

This issue of pneumatic controller emissions has been part of a larger debate regarding EPA's regulations under the Climate Action Plan. When the Obama Administration initiated its Climate Action Plan regulatory efforts, it argued that new regulations – in this instance Subpart OOOOa and CTG – were needed to meet a 45 percent emissions reduction target for methane from 2012 to 2025. Industry countered that the Subpart OOOO regulations met this target for oil and natural gas production. It was a statement largely borne out by the GHGI reports.

Subsequently, EPA adjusted the GHGI by increasing emissions primarily related to pneumatic controllers. Key to EPA's rationale was a conclusion that reported data were showing higher emissions – based on EPA emissions factors. And, since only about thirty percent of oil and natural gas operators directly reported, EPA needed to scale up the other emissions in the inventory. Industry objected to this arbitrary scale up because, when EPA set the limits to determine direct reporters, it argued that it would get about 85 percent of emissions from 30 percent of the operators. This was largely valid because roughly 70 percent of the operators would be low producing wells. But, in its scale up, EPA increased the pneumatic controller calculated emissions on the basis of number of operators – or effectively added an amount equal to twice the reported amount.

[1] ONG – oil and natural gas

The new study should change all of these calculations. And, in doing so, it should demonstrate that the necessity for Subpart OOOOa and the CTG are substantially overstated. Significantly, unlike the unfortunate history of using available but not directly related analyses for the recent EPA regulations, this new report was designed and conducted by EPA.

Small Business Implications

Because Subparts OOOO and OOOOa are NSPS, they are perceived as regulations that would have limited small business implications. They are largely thought to be capital requirements that are applied to new natural gas and oil wells. But, their application is different.

Subpart OOOO

Subpart OOOO was characterized as a regulation directed at managing hydraulically fractured natural gas wells. This was only true in part – its application to REC. However, even then, the scope of its definitions was broader. While the concept of REC – or green completions – and the framework of the regulations were based on water based hydraulically fractured wells with long horizontal legs developing shale formations, the regulation language captured other types of wells.

One key example is nitrogen fractured vertical wells. Instead of using water as the fracturing media, these wells use nitrogen. However, the REC process is predicated on getting produced gas into pipelines quickly to prevent emissions. This concept works well for water fractured wells because gas-water separation is straightforward. It does not work for nitrogen fracturing because a gas-nitrogen stream cannot be readily separated. This issue has a specific small business consequence. Nitrogen fracturing is not used for large gas wells with horizontal legs. It is used for small vertical wells in limited formations; these wells are developed by small business operators. EPA should have used greater efforts to assure that its scope was appropriate for the technology it required. Clearly, in this instance, it missed. Equally clearly, in the five years since the Subpart OOOO regulations were finalized, EPA has been unwilling to straightforwardly address its failure. Rather, it has tried to maneuver around the edges using the concept of changing the definition of low pressure wells. It is a strained and ineffective path. EPA needs to simply remove nitrogen fractured wells from the scope of Subpart OOOO.

Another aspect of the Subpart OOOO REC requirements that affects small business relates to EPA's failure to distinguish between unconventional and conventional formations in the scope of Subpart OOOO (and Subpart OOOOa when it expanded the REC requirements to oil well completions). The tight formations characterized by the success of America's development of shale gas and shale oil formations are characteristically unconventional formations. However, hydraulic fracturing is also used in the development of conventional formations. While EPA's Subpart OOOO definition would appear to reflect this distinction, when a small business operator developing conventional oil formations in the Illinois Basin sought clarification that its operations were not subject to Subpart OOOOa, it was rebuffed.

Subpart OOOOa

Subpart OOOOa expanded oil and natural gas production regulations in significant and adverse aspects for small business operators.

A primary aspect of Subpart OOOOa was the decision to change the targeted emissions from VOC to methane. Not only did Subpart OOOOa target methane, it revised the scope of Subpart OOOO. These changes did nothing to improve oil and natural gas production emissions management since VOC and methane are emitted simultaneously and the regulations capture both. It was a political decision because it would open a pathway to regulate existing sources on a national basis. This change is a direct effort to pursue marginal wells and shut them down.

To appreciate the small business impact, it is important to understand that – unlike one time capital requirements for control equipment – the LDAR program creates an enduring operating cost for the life of the well. Because oil and natural gas wells decline, the cost effectiveness of this requirement changes as the costs must be borne by ever smaller production. When EPA deleted the low production well exclusion for its LDAR requirements, it harmed small business producers. First, the long-term value of wells drilled under the NSPS will be less. They will not be economic as long and particularly will not have value to be sold to small businesses. EPA did not include this consequence in its BSER determinations. Second, if EPA develops a nationwide existing source rule with the same framework, the broad fabric of America's marginal wells (oil and natural gas) will be destroyed.

Control Technique Guidelines

The oil and natural gas production CTG adversely affects small business operators because it applies to low producing operations. The justification fails to consider the costs that must be borne by small operators with low producing wells.

Recommendations

The Trump Administration decision to review the Subpart OOOO and OOOOa regulations can allow for a more thorough understanding of their key components and to make them more cost effective. As a first step, the regulations should be changed for oil and natural gas production to apply to VOC emissions rather than methane. This change would reinstate the basic framework from the 2012 promulgation of Subpart OOOO. It would have little impact on new source emissions reductions of methane since VOC and methane are emitted together and control simultaneously. At the same time, it would eliminate the clearly political decision to create a pathway to nationwide federal regulations of existing sources through rarely used Section 111(d). The primary consequence of applying Section 111(d) to oil and natural gas production facilities is the devastating impact it could have on small business low production wells – an unnecessary consequence that reduces American oil and natural gas production without generating substantial environmental benefits.

Further, the Administration's decision to stay the effective date of the fugitive emissions program in Subpart OOOOa and open the record to reconsider these requirements should lead to a modification of regulations applying to low producing wells – a modification to reflect the distinct differences in the nature of these wells compared to the large hydraulically fractured wells the NSPS were originally conceived to address.

In fact, EPA should utilize its authority under the CAA to create a subcategory within the Oil and Natural Gas Sector that would apply to low producing oil and natural gas wells. At this time, it should reserve that subcategory for possible future use. Such an action would allow for the analyses of regulations of these small business operations to be based on their limited emissions and their economics. It would assure that any BSER is applicable to these operations.

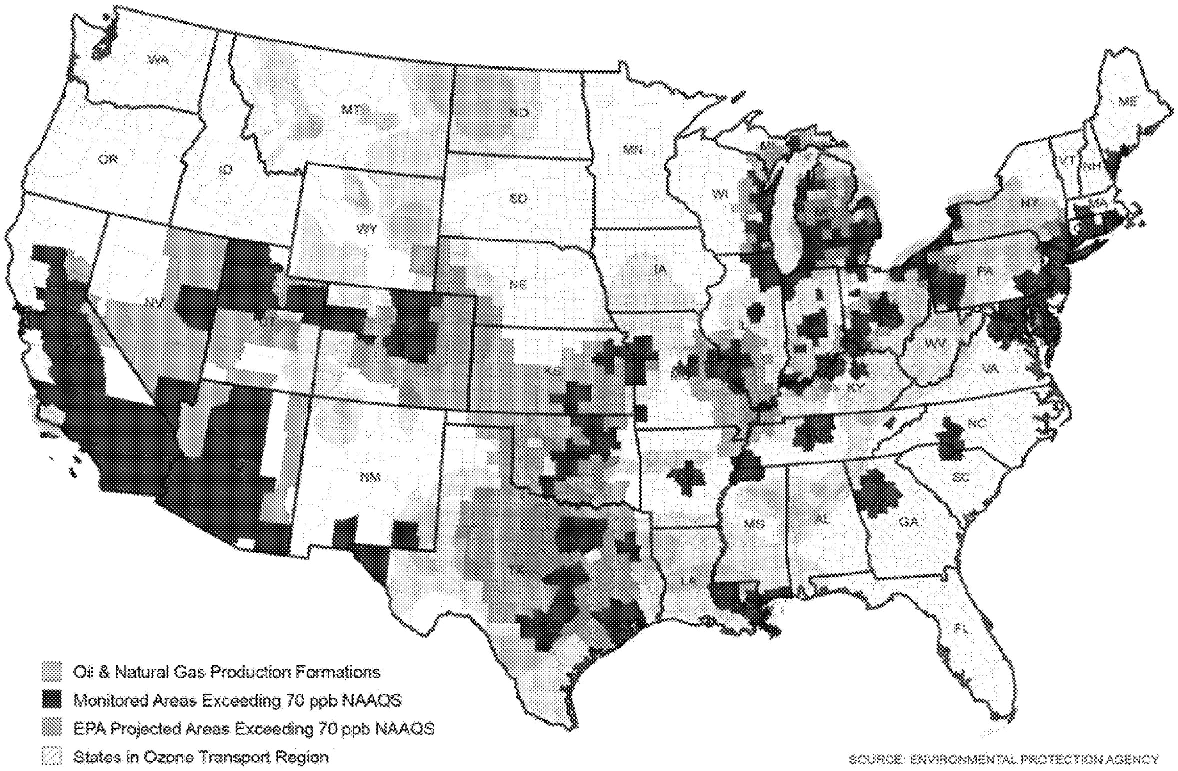
The CTG need to now be considered in the context of the Administration's actions on Subpart OOOOa and OOOO. Because these regulations are positioned to be reconsidered, the CTG need to be addressed accordingly. It should be suspended or withdrawn before it becomes a part of SIP revisions. After judgements are made on Subpart OOOOa and OOOO, the CTG need to be reconsidered and any further action should be based on both an accurate understanding of the emissions from existing sources and a true evaluation of the technology requirements as they apply to existing sources. Additionally, a thorough assessment of the impacts on small businesses must be made. Importantly, any such analysis needs to recognize that the dynamics of oil and natural gas production – as the graphics previously presented show – reflects the inevitable turnover of wells. Consequently, as time passes, the inventory of wells will become populated with those that meet the requirements of the NSPS and the existing wells that would be affected by the CTG will be overwhelmingly low producing, small business owned wells.

EPA needs to revamp its NSPS and CTG processes to assure that it has adequate information on the nature of air emissions and the applicability of regulations to manage those emissions. The recent experiences with Subpart OOOOa and CTG, in particular, indicate that EPA failed in its fundamental statutory duties to identify BSER and RACT technologies. It needs to develop and use studies that are regulatory based – and it needs to have the capability to thoroughly understand and analyze external information that is submitted and is specious.

Ozone National Ambient Air Quality Standards (NAAQS)

EPA should reconsider the 2015 revision to the Ozone NAAQS. The Ozone NAAQS can have a bearing on both the NSPS and CTG requirements for oil and natural gas production. American oil and natural gas operations are located where the resources exist. Unlike manufacturing facilities, they cannot choose where to operate. Historically, much of America's oil and natural gas has been located in largely rural areas. Recent development of American shale resources has placed operations closer to populated areas – many of which are in Ozone nonattainment areas. However, EPA's decision to lower the Ozone NAAQS captures areas that have previously been in attainment. The following map provides a perspective on the interaction between American production areas and nonattainment with the new Ozone NAAQS.

Ozone Nonattainment Areas Impacting American Oil & Natural Gas Production



While oil and natural gas production facilities have always been subject to RACM in current Ozone nonattainment areas, the CTG changes the regulatory framework significantly. Part D of the CAA provides for states to impose RACM on existing stationary sources as a part of the requirements to demonstrate attainment or Reasonable Further Progress toward attainment. These RACM requirements, however, apply to stationary sources of a specific size depending on whether an Ozone nonattainment area is classified as Moderate, Serious, Severe or Extreme. Therefore, regulation of existing oil and natural gas production facilities depended both on their size and the status of the Ozone nonattainment area. The CTG in general does not set emissions thresholds for its application. As such, for large or small producers, or large or small emitters, the regulatory burden will apply and will apply far more broadly.

Ozone has consistently been the most difficult primary NAAQS for certain areas to meet. The following figures demonstrate the reality of Ozone NAAQS nonattainment. Figure 1 presents EPA's assessment of the areas of the country that fail to meet the 1997 Ozone NAAQS of 84 ppb (8 hour). Figure 2 presents EPA's assessment of the areas of the country that will fail to meet the 2008 Ozone NAAQS of 75 ppb (8 hour) in 2020. Figure 3 presents EPA's assessment of the 2015 Ozone NAAQS by 2025.

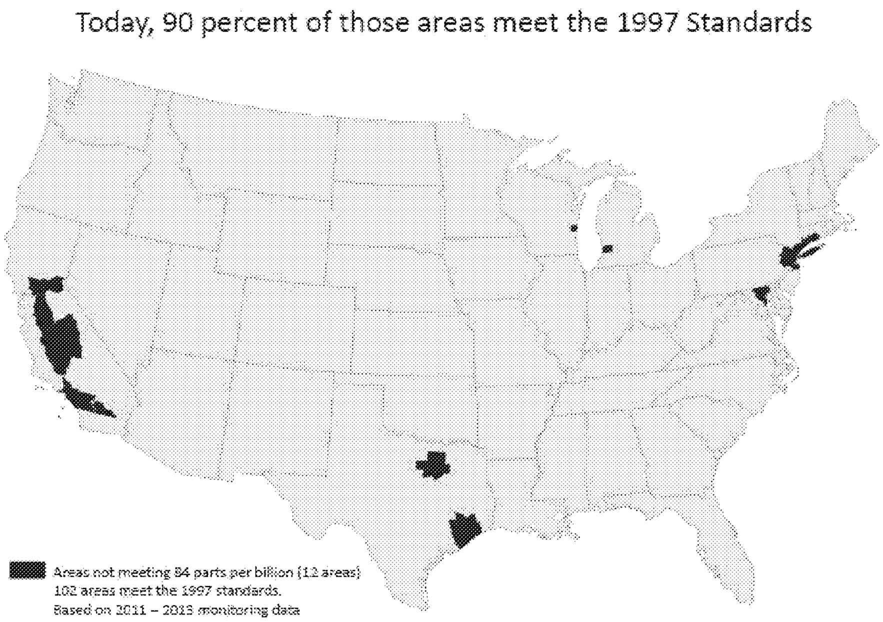


Figure 1 Source: Environmental Protection Agency

Figure 2 Source: Environmental Protection Agency

Figure 3

Source: Environmental Protection Agency

EPA's analysis shows that there are certain areas of the country that are enduring Ozone NAAQS nonattainment areas – areas that cannot meet any Ozone NAAQS that has been promulgated. The same areas that failed to meet the 1997 Ozone NAAQS and the 2008 Ozone NAAQS also will fail to meet the 2015 NAAQS by 2025 and, realistically, any time until well after 2030. What this means is that EPA's claimed health benefits from the 2015 NAAQS will not occur in these enduring nonattainment areas.

Equally important, the regulatory requirements in these enduring nonattainment areas will be no different under the 2015 NAAQS than they are under the 2008 NAAQS. These areas are subject to regulation under Part D – Plan Requirements for Nonattainment Areas of the CAA.

Part D was created in the 1990 CAA amendments. It creates a series of specific minimum requirements for each area in Ozone NAAQS nonattainment initially based on the area's ozone monitoring values relative to the Ozone NAAQS. Areas are classified as Marginal, Moderate, Serious, Severe and Extreme. Each classification is given a specific time frame in which to attain the Ozone NAAQS. Importantly, if an area fails to meet the NAAQS in its allotted compliance period, it is reclassified to a higher classification, required to implement the mandatory requirements and given an extension of time to meet the NAAQS. Part D requirements were initiated after the 1990 CAA amendments with attainment dates ranging from 1993 to 2010. Even with attainment date extensions, these dates have passed.

The significant impact of Part D is that perpetual nonattainment eventually produces a baseline of regulations and requirements of additional annual percentage reductions. Since these areas have been subject to Part D for 25 years, their future regulatory requirements will be the same iterative percentage reductions under the 2008 NAAQS as the new one. Adopting the 2015 NAAQS will produce the same regulatory requirements for these areas as the 2008 NAAQS.

EPA has stated in its support documents for its 2015 Ozone NAAQS that:

> Existing and proposed federal rules . . . will help states meet the proposed standards by making significant strides toward reducing ozone-forming pollution. EPA projections show the vast majority of U.S. counties with monitors would meet the proposed standards by 2025 just with the rules and programs now in place or under way.

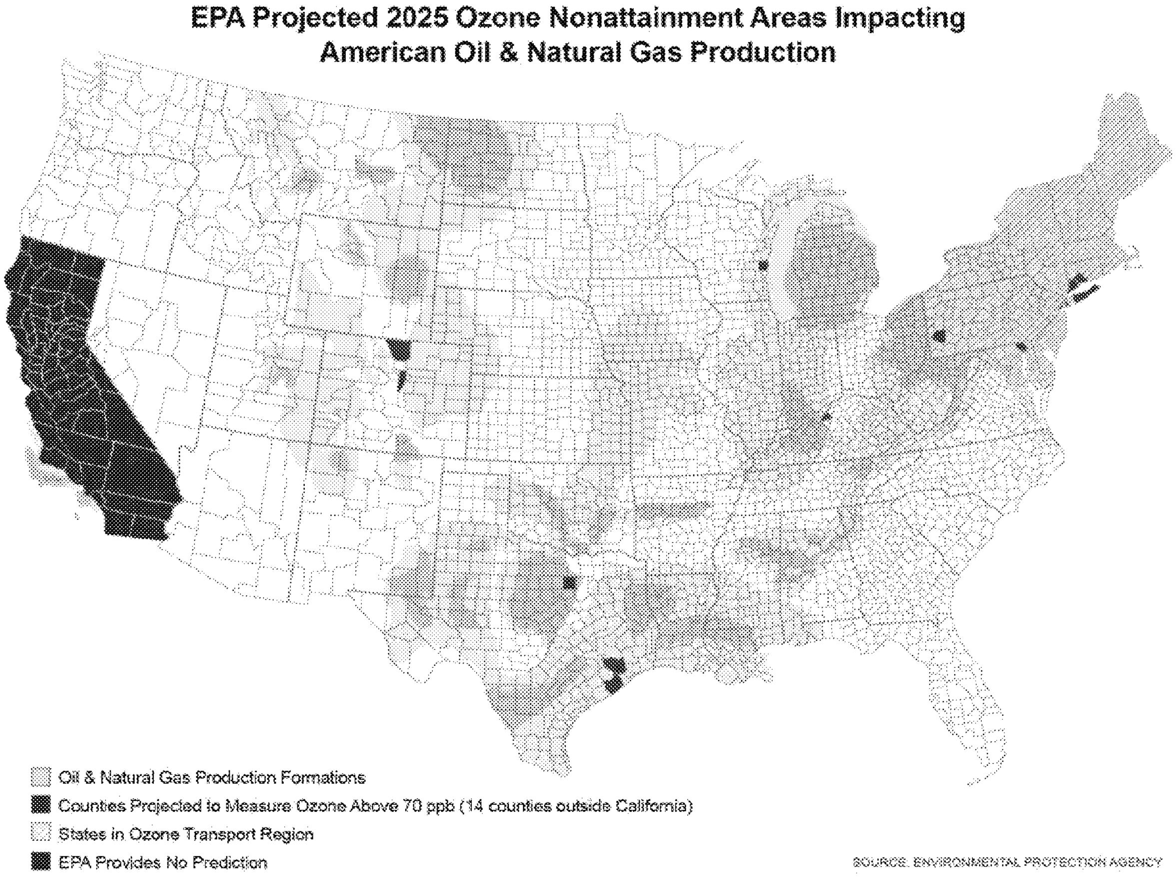
Consequently, these national, federal requirements will essentially protect the overwhelming number of areas that would be placed in Ozone NAAQS nonattainment by the 2015 NAAQS without any of the local actions that would be required from such categorization.

For these areas that EPA projects would reach attainment using only national, federal mandates regardless of the NAAQS, promulgating the 2015 NAAQS will compel them to be subject to the requirements of Part D of the CAA. Because Part D imposes a series of minimum requirements, the 2015 NAAQS will impose emission controls on new sources in those areas, including offsets, which will be burdensome, cost ineffective and unnecessary since EPA believes these areas would reach attainment using only its national regulations.

Once an area becomes subject to Part D, minimum requirements are mandated. For example, all new construction must not only comply with rigorous emissions controls, but all remaining emissions must be "offset" by reductions in existing emissions that are not otherwise regulated. Many of the areas that would fall into initial Ozone NAAQS nonattainment but would later attain the NAAQS are largely rural or with smaller municipalities. These areas will likely have limited existing emissions sources to regulate. These areas will face either an effective construction prohibition or the choice of shutting down existing operations that employ current workers.

The oil and natural gas production CTG get pulled into this murky process. Enduring Ozone nonattainment areas already are a possible target for RACM requirements, but those requirements are predicated on the size of the source and therefore not imposed without consideration of their impact on emissions and with localized consideration of cost effectiveness. For the newly captured Ozone nonattainment areas that EPA believes will meet the 2015 Ozone NAAQS using national, federal regulations – an assessment made without the inclusion of the proposed CTG – the application of the proposed CTG is unnecessary to reach attainment. However, because the CTG would be applied and would be applied to such small sources, these reductions are also removed from the possible pool of emissions that could be managed as a part of emissions offsets needed to build new facilities. In many of these areas, new facilities are likely new oil and natural gas wells. Consequently, the impact of the CTG would be to limit new production.

As the following graphic shows, EPA projects that only a few areas will remain in Ozone nonattainment in 2025.



This projection is based on regulatory actions taken without the CTG. It demonstrates that the CTG is not essential to Ozone NAAQS attainment. Certainly, in some enduring nonattainment areas some oil and natural gas production facilities would be subject to RACM, but these decisions would be based on local conditions and the economic circumstances of the oil and natural gas production operations in those areas. The CTG would make all oil and natural gas production operations subject to the CTG without a compelling need – based on EPA's own projections of Ozone attainment – and without the opportunity to assess local need. Moreover, it would eliminate possible actions that could facilitate new construction as offsets and thereby unnecessarily threaten economic growth in these areas.

Recommendations

EPA should reconsider the 2015 Ozone NAAQS revision. Given that the enduring Ozone nonattainment areas fail to attain the 2015 NAAQS and would be essentially undertaking the same regulatory program as under the 2008 NAAQS, the health claims for the 2015 NAAQS need to be carefully reviewed. Additionally, if the areas that become nonattainment as a result of a lower NAAQS but would attain it without local controls, there are no additional health benefits in those areas but there would be unnecessary regulatory consequence that should not be compelled on these communities.

WATER REGULATIONS

The Clean Water Act (CWA) can impact American oil and natural gas producers in several ways. The most prominent involve regulations that result from interpretation of Waters of the United States (WOTUS) and Effluent Limitations Guidelines (ELG).

Waters of the United States

Oil and natural gas are found throughout the United States. Significant reserves underlie arid areas. These operations are distant from waterbodies. However, resolving the ongoing deliberations on the scope of the navigable waters definition can have significant consequences.

Most notably, certain elements of the CWA are linked to whether they affect navigable waters. For example, the Spill Prevention, Control and Countermeasures (SPCC) planning requirements are based in part on the amount of oil at a site and in part on whether a potential spill would reach navigable waters. Consequently, a WOTUS definition that reaches well beyond truly navigable waters and adjacent wetlands can subject facilities that would never actually impact them. Yet, the SPCC plan regulations require substantial capital investment for the construction of protective equipment. If the likelihood of a spill affecting navigable waters is miniscule, these requirements are neither cost effective nor environmentally beneficial.

Another significant WOTUS related issue involves CWA Section 404. Here again, the CWA requires dredge and fill permits if navigable waters are affected. All oil and natural gas production facilities require construction of necessary pads for operation. When this construction must take place near waterbodies, the necessity of obtaining a Section 404 permit is understandable. But, when construction occurs in arid topography – far from waterbodies – Section 404 permits are neither necessary nor appropriate.

Small Business Implications

For small business operators, complying with costly planning and investment requirements that are distant from navigable waters diverts capital from the necessary expenditures to keep wells operating, particularly low producing wells.

Recommendations

The Trump Administration decision to act on the WOTUS regulations to reflect the Scalia decision in the *Rapanos v. United States* case is a sound first step to pull the scope of CWA jurisdiction back toward Congressional intent in its 1972 CWA legislation. At that time, the context of navigable waters was far clearer than it now appears to be. Then, during Senate and House of Representatives debate on the CWA, the definition relied on a widely understood use of the term "navigable waters". Only when the CWA was reported by a House-Senate conference committee did the term "waters of the United States" appear. Anyone familiar with the chaos of Congressional debate during the deliberations of a conference report knows that it would not have drawn the attention that it has lastingly produced.

Effluent Limitations Guidelines

Waste water discharges are regulated through the development of ELG. ELG then become the basis for National Pollutant Discharge Elimination System (NPDES) permits by either state or federal permitting agencies. The ELG for direct discharges from oil and natural gas production facilities was written in 1979. Generally, it prohibits oil and natural gas produced water direct discharges. While this conclusion was arguably not Best Available Control Technology Economically Achievable (BATEA) – the CWA requirement for waste water treatment – even in 1979, it reflected that the widespread use of underground injection of produced water was the preferred option for over 95 percent of produced water volumes at that time. No major review has occurred since, but the industry has changed.

In recent years, EPA turned again to produced water discharges from oil and natural gas production operations. First, it evaluated possible ELG for coal bed methane production but ultimately chose not to pursue it. Then, it turned to shale gas production, largely triggered by issues in Pennsylvania where underground injection options are limited.

EPA created pretreatment standards for discharges of wastewater from onshore unconventional oil and gas (UOG) extraction facilities to municipal sewage treatment plants (also known as publicly owned treatment works, or POTWs). The UOG extraction facilities POTW pretreatment ELG creates two issues that need to be addressed.

First, in defining UOG extraction facilities, EPA missed the mark. While EPA publicly described the scope of its ELG as applying to shale formations considered to be unconventional, its final rule included formations considered as conventional formations that had been developed for decades prior to the advent of shale gas.

Second, and more significant, EPA failed to meet its fundamental mandate to develop ELG based on BATEA. The BATEA concept requires EPA to identify technologies that manage the waste in effluents, determine if the technology is available as a commercial application, and assess whether it is economically achievable. In its UOG extraction facilities pretreatment ELG, EPA identified no technologies and made no economic analysis – though technologies exist. Instead, it merely concluded that it would prohibit discharges to POTWs from UOG extraction facilities. It argued that underground injection and recycling would be available as a management option. But the reality is that underground injection in some states – notably Pennsylvania – is not an option and cannot be assumed to always available. Similarly, recycling of produced water is an option when drilling activity is high enough to consume the water, but as EPA finalized the ELG, drilling activity and recycling were declining.

We addressed these issues and EPA's positions more extensively in comments filed on the EPA proposal in our comments in July 2015 as follows:

> Once EPA initiated the process to develop a pretreatment ELG for UOG extraction waste waters sent to POTWs, it needs to fully assess the potential implications of its actions on current and future management of this waste water. As EPA states:
>
> > EPA develops ELGs that are technology-based regulations for specific categories of dischargers. EPA bases these regulations on the performance of control and treatment technologies. The legislative history of CWA section 304(b), which is the heart of the effluent guidelines program, describes the need to press toward higher levels of control through research and development of new processes, modifications, replacement of obsolete plants and

> processes, and other improvements in technology, taking in to account the cost of controls. Congress has also stated that EPA need not consider water quality impacts on individual water bodies as the guidelines are developed….
>
> There are four types of standards applicable to direct dischargers (facilities that discharge directly to surface waters), and two types of standards applicable to indirect dischargers (facilities that discharge to POTWs), described in detail below.

More specifically, in describing Pretreatment Standards for Existing Sources (PSES) and New Sources (PSNS), EPA states:

> …section 307(b) of the Act calls for EPA to issue pretreatment standards for discharges of pollutants from existing sources to POTWs. Section 307(c) of the Act calls for EPA to promulgate pretreatment standards for new sources (PSNS). Both standards are designed to prevent the discharge of pollutants that pass through, interfere with, or are otherwise incompatible with the operation of POTWs. Categorical pretreatment standards for existing sources are technology-based and are analogous to BPT and BAT effluent limitations guidelines, and thus the Agency typically considers the same factors in promulgating PSES as it considers in promulgating BAT. … Similarly, in establishing pretreatment standards for new sources, the Agency typically considers the same factors in promulgating PSNS as it considers in promulgating NSPS (BADCT)[2].

These statements clearly envision a process that assesses technology designed to meet specific standards whether they are Best Practicable Technology (BPT) or Best Available Technology (BAT) or BADCT. These concepts include analyses of the technologies that can be applied to the waste water being addressed, evaluating the reductions achieved and the costs. But, EPA did not undertake such a robust analysis in this case. Rather, as EPA states:

> EPA does not propose an option with numerical discharge pretreatment requirements prior to discharge to a POTW for the following reasons. First, the existing requirements for direct discharges of UOG extraction wastewater in the Onshore Subcategory require no discharge of pollutants. As explained above, EPA generally establishes requirements for direct and indirect discharges so that the wastewater receives comparable treatment prior to discharge to waters of the U.S.
>
> Second, the option EPA proposes, zero discharge of pollutants in UOG extraction wastewater to POTWs, is widely available, economically achievable and has no incremental (and, therefore,

[2] Best Available Demonstrated Control Technology

> acceptable) non-water quality environmental impacts. Because the proposed zero pollutant discharge requirement is current practice and, therefore, clearly both available and achievable, any option that includes non-zero discharge requirements for any pollutants would potentially increase pollutant discharges from current industry best practices. Such an option would not fulfill the CWA requirement to establish limitation s based on ''Best Available Technology Economically Achievable'' (CWA section 301(b)(2)(A)), or the CWA goals of eliminating the discharge of pollutants in to navigable waters (CWA section 101(a)(1)).
>
> Third, EPA does not have any data to demonstrate that UIC capacity nationwide will be expended and that this current management approach will not be available in the future (DCN SGE00613). In fact, industry has been managing oil and gas extraction wastewater through underground injection for decades. In recent years, industry has greatly expanded its knowledge about the ability to re-use UOG flowback and long-term produced water (the major contributors to UOG extraction wastewater by volume) in fracturing another well. Consequently, while the UOG industry continues to grow and new wells are being fractured, the need for UIC capacity for UOG extraction wastewater is decreasing, even in geographic locations with an abundance of UIC capacity (see TDD Chapter D.2).
>
> Fourth, EPA identified technologies that currently exist to treat dissolved pollutants in UOG extraction wastewater. Relative to underground injection and reuse/recycling to fracture another well (the basis for the preferred option EPA proposes), these technologies are costly, would result in more pollutant discharges, and are energy intensive. While EPA did not attempt to calculate a numerical standard for TDS, data collected for this proposed rulemaking demonstrate that the current technologies are capable of reducing TDS (and other dissolved pollutants) well below 500 mg/L. To the extent that these technologies or others are developed in the future to reduce pollutants in UOG extraction wastewater to enable them to be reused for purposes other than fracturing another well, these pre-treated wastewaters can be used directly for the other applications without going through a POTW.

Looking at each of these reasons separately demonstrates that EPA has not made a plausible argument for failing to develop a numerical standard.

First, while EPA indicates that it "…generally establishes requirements for direct and indirect discharges so that the wastewater receives comparable treatment prior to discharge to waters of the U.S.", it should recognize that relying on a 39 year old ELG as a basis for action raises a strong signal that a more analytical approach is necessary. Similarly, if the Agency's decision to imbed its pretreatment ELG in the Onshore Subcategory becomes a barrier to making a more thoughtful approach to define a numerical standard because of this general comparability framework, EPA should create a new Subcategory that would allow for a result that reflects the future more than the past.

Second, while UIC Class II wells are clearly an effective management option for UOG extraction waste waters, injection is not a treatment technology. Rather than assume the availability of UIC as the only technology to be used by the industry to manage its waste water – a decision that relies on unsubstantiated determinations of its widespread future availability – EPA should define a numerical, technology based BATEA for managing UOG extraction waste waters. Once the BATEA is determined, the issue of whether it is more cost effective than UIC will be a determination by the discharger. But, for those instances where UIC is not readily available – such as the circumstances that drove Pennsylvania producers to use POTWs – there would be an alternative that EPA has determined meets the technology standards of the CWA.

Third, EPA's action hinges on its assumptions that UIC capacity will continue to be a viable and cost effective option for all UOG extraction waste waters. Yet, its supporting material for this conclusion is thinly substantiated. One of its cited documents – DCN SGE00613 – is a Meeting Summary from a February 2013 meeting with industry representatives. IPAA was a participant in the meeting. EPA deduces from this document that "EPA does not have any data to demonstrate that UIC capacity nationwide will be expended and that this current management approach will not be available in the future." This meeting never delved into a deep discussion that would yield such a conclusion; it was a general briefing to describe the nature of oil and gas extraction, the technologies that manage waste water for disposal or reuse, and the cost effectiveness of various waste water treatment to manage TDS. The text of the document states:

> There is no widespread discussion in the industry about lack of injection for disposal capacity but one area that tends to have lower capacity is the Marcellus region. This is because the states of Pennsylvania and West Virginia require produced water be disposed of in the zone from which it was removed or deeper. Because of its depth, disposal into zones deeper than the Marcellus shale is not feasible.

If anything, this document emphasizes the limitations in certain regions regarding the availability of injection wells. But, it is clearly not a robust assessment of future UIC capacity. EPA also references issues regarding future UIC capacity based on a second document – TDD Chapter D.2[3] – by stating:

[3] Technical Development Document for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction, EPA-821-R-15-003, March 2015

> Consequently, while the UOG industry continues to grow and new wells are being fractured, the need for UIC capacity for UOG extraction wastewater is decreasing, even in geographic locations with an abundance of UIC capacity.

However, this document does not assess future capacity issues; it merely reports on the current number of Class II disposal wells.

Industry sees a different and much less certain picture of future UIC capacity.

- One, as EPA reports, but later ignores, there are some areas where UOG extraction is intense – such as the Marcellus Shale – where UIC capacity does not exist.
- Two, because UOG extraction well waste water cannot be reinjected for oil or gas recovery, this waste water must be sent to UIC disposal wells or managed. As a result, there will be pressure to expand existing disposal wells or drill new ones.
- Three, EPA discounts this pressure by emphasizing waste water recycling/reuse. Recycling and reuse are viable and valuable but they are not a panacea. Real limits on recycling/reuse include the pace of new well development, the proximity of new wells to the waste water, the adequacy of water volumes in a specific area and the contaminant levels in the water. Moreover, as certain fields become more production-focused, as opposed to having aggressive active exploration, there are greater needs to manage produced water and even fewer opportunities to recycle/reuse it for fracturing operations. As such, recycling/reuse activities are not only driven by the intensity of drilling activities in a certain resource play but by its stage of development. As time progresses, the Marcellus Shale, for example, will experience an even greater need for disposal options.
- Four, in the time period that EPA has been developing this ELG proposal, the regulatory framework for Class II UIC wells has been subjected to new challenges, particularly for disposal wells. As environmental fossil energy/fracturing opponents have failed to show that state regulated fracturing presents unmanageable environmental risks, they have turned to other elements of unconventional oil and gas production. One of these is UIC disposal. Over the past several years issues related to triggered seismicity have been imputed to UIC disposal wells. These allegations threaten new well permits and existing operations whether caused by technical regulatory constraints or local opposition. Similarly, EPA initiated a review of the process that states use to exempt aquifers from regulation under the SDWA. Aquifers related to oil and gas extraction have historically been excluded from the SDWA scope but if changes are made to areas that are possible disposal sites, future UIC options could be diminished. Primacy delegation under the SDWA is being challenged. Efforts are active to stir up opposition to waste water movement from one state to another. Collectively, these challenges to

UIC Class II disposal options can limit future capacity at a time when assumptions about reuse must be cautious not ebullient.

Consequently, EPA's reliance on the past success of UIC to serve as the basis for a zero discharge ELG is misplaced.

Fourth, EPA too readily dismisses treatment technologies as "…costly, would result in more pollutant discharges, and are energy intensive" compared to UIC or reuse. These technologies may be more costly and result in pollutant discharges. However, the CWA does not demand that BATEA be inexpensive and discharge free. It requires that the technology be what the description says – the best available technology economically achievable. It is EPA reliance on a non-CWA management technology – injection wells under the SDWA – that brings about that comparison. And, as stated above, EPA reaches the conclusion to rely on Class II UIC disposal wells too cavalierly.

Instead, EPA needs to fully assess a variety of technologies – most of which have been developed as a part of the industry recycling and reuse initiatives – to determine their capacity to manage waste water in the context of pretreatment. These technologies might include sedimentation, filtration, chemical precipitation, dissolved air flotation, biological treatment, reverse osmosis (RO), forward osmosis (FO), evaporation (no recovery), evaporation with condensation, membrane distillation, and crystallization. Certainly, these technologies produce different outcomes and are appropriate for different waste waters. Their costs and their effectiveness will differ. But, until EPA evaluates them, no one knows which may constitute BATEA for pretreatment. For example, the following table presents some framework of technologies that might be considered for recycling and reuse. They may bear on a BATEA analysis as well, but EPA needs to make the analysis necessary for such a determination.

Treatment Technology	Max TDS Recommended for Treatment (ppm)	Relative Cost	Commercially Available
Reverse Osmosis Membrane	50,000	$	Yes
Forward Osmosis Membrane	100,000	$$	No
Evaporation*	200,000	$$	Yes
Membrane Distillation	280,000	$$	No
Crystallization	500,000 +	$$$$$	Yes

While EPA may raise questions about whether they are too costly compared to other options, ultimately, it is the producer that will have to make an economic decision among the various options available. By making no BATEA analysis of technology options, EPA prevents that decision from being considered.

EPA needs to reconsider the UOG extraction facilities pretreatment ELG and determine appropriate BATEA for actual unconventional oil and natural gas development.

Small Business Implications

Taken together, EPA's action to cover conventional oil and natural gas production and to prohibit the discharge of conventional produced water to POTWs in addition to its prohibition of direct discharges of produced water can fall most heavily on small business operators. State permitting agencies have the responsibility to protect their waters – and they do so effectively. Even without an ELG, state permit writers must determine whether a discharge option is appropriate and to define technology options using Best Professional Judgement (BPJ) decisions under the CWA. If a state has determined that it can meet its water management responsibilities and allow conventional oil and natural gas produced water to be managed in POTWs, EPA should not preclude it, particularly if that option is essential to small businesses.

Recommendations

EPA needs to reconsider at least the 2016 ELG for onshore UOG extraction facilities POTWs. EPA's absolute failure to develop technology based BATEA requirements undermines the fundamental premise of the CWA and sets a precedent for all future oil and natural gas production ELG decisions that now rely on decisions made in 1979 regarding a vastly different industry.

SOLID WASTE REGULATIONS

The Resource Conservation and Recovery Act (RCRA) defines the federal management structure for hazardous (Subtitle C) and nonhazardous (Subtitle D) solid wastes. Oil and natural gas production operations produce wastes that must be managed as solid wastes, primarily drilling fluids and produced waters at production sites. Ultimately, produced water is regulated under the federal CWA or Safe Drinking Water Act (SDWA). In 1980, Congress concluded that state regulatory programs managing oil and natural gas production wastes were designed to apply to those wastes and that Subtitle C was not an appropriate option. In 1988, EPA completed a Congressionally mandated Regulatory Determination concluding that:

> RCRA Subtitle C was not appropriate for oil and natural gas production wastes;
>
> State programs were effectively managing these wastes; and,
>
> Applying RCRA Subtitle C to production wastes would significantly and adversely affect American oil and natural gas production.

Since that decision, Keep It in the Ground environmental advocates have repeatedly sought to subject oil and natural gas production wastes to federal requirements knowing that it would result in devastating consequences for American production.

Recently, these groups turned their attention to Subtitle D and extracted a consent decree from EPA to determine if it needs to develop federal regulations under Subtitle D.

EPA has a long history working with states since its 1988 Regulatory Determination. Some of this activity has been formal such as the state review programs initiated after the Regulatory Determination and currently conducted through the STRONGER (State Review of Oil and Natural Gas Environmental Regulations) process. Other actions have been informal working with individual states, with the Interstate Oil and Gas Compact Commission (IOGCC) and with the Ground Water Protection Council (GWPC). Given these ongoing interactions with state programs, EPA clearly understands the effectiveness of these programs.

Subtitle D frames very general authority for EPA. However, there are some provisions that were used by the environmental groups to trigger the litigation leading to the consent decree. These are:

> 40 CFR, Part 257 – **Criteria for Classification of Solid Waste Disposal Facilities and Practices** - establishes regulatory standards to satisfy the minimum national performance criteria for sanitary landfills. These criteria established standards for determining whether solid waste disposal facilities and practices may pose adverse effects on human health and the environment. Facilities that fail to meet the criteria are "illegal dumps" for purposes of state solid waste management planning efforts under Subtitle D. *The criteria provide the basis for enforcing the prohibition on "open dumps" and may be used by citizens' suits in Federal District Court.*
>
> 40 CFR, Part 256 – **Guidelines for Development and Implementation of State Solid Waste Management Plans** – establish the elements that state solid waste management plans must contain to qualify under RCRA Subtitle D.

EPA has rarely utilized its authority under these sections of RCRA. However, each of these sections include requirements used by the environmental groups arguing that EPA must review its Subtitle D programs every 3 years and determine whether it needs to develop federal regulations and state guidelines or if the current programs, including state regulations, are adequate.

Now, under the consent decree, EPA must determine whether to act under these sections by March 2019. EPA can determine that state programs are – as they clearly have been – effective in managing production wastes and no action is needed under Subtitle D. Or, EPA can propose a Subtitle D federal program. Given the unique nature of these wastes, neither Subtitle C nor Subtitle D provide a framework for a production wastes regulatory structure – particularly a national regulation that could not reflect the different environments of the oil and natural gas producing states. Moreover, Subtitle D does not compel states to adopt federal regulations. With regard to production wastes, the clear history of successful, well managed state regulations means that states would not choose to sacrifice their programs for an untried federal one.

However, if EPA created Subtitle D regulations, that action would expose independent producers to litigation by environmental agitators. Under RCRA, citizen suits can be directed at individual operators that fail to comply with federal regulations. Consequently, a producer complying with state regulations that do not adopt the federal requirements would be exposed. Clearly, this is an objective of Keep It in the Ground environmentalists that use litigation as a tool to stop production, as recent efforts to use RCRA to litigate against producers regarding underground injection alleged to induce seismic events demonstrates. While that initiative was rejected in federal courts, it demonstrates the strategy that would arise if EPA writes Subtitle D federal regulations.

Small Business Implications

Small business operators are a risk if EPA were to develop unnecessary federal Subtitle D regulations. They would be convenient targets for Keep It in the Ground environmentalists to attack with citizen suits knowing that the litigation costs would severely tax small business resources.

Recommendations

EPA should act in 2017 to publish a determination that it does need to develop oil and natural gas production waste regulations under Subtitle D. An early action would demonstrate that the historic federal-state relationship on managing production wastes remains strong.

SAFE DRINKING WATER ACT

Exempted Aquifers

On March 23, 2016, the Natural Resources Defense Council (NRDC) filed a petition with EPA under the Administrative Procedure Act (APA) seeking changes to the aquifer exemption (AE) program under the SDWA.

Among other things the petition demands that EPA:

1. Impose a moratorium on all AE related decisions including granting new exemptions or expanding the boundaries of existing exempt areas.
2. Update the regulations and criteria for designating exempt aquifers through a formal rulemaking process.
3. Eliminate criteria that allow aquifers to be exempted when hydrocarbons are demonstrated to be naturally occurring in the groundwater.
4. Consider increasing the threshold for Underground Source of Drinking Water (USDW) protection from 10,000 mg/L TDS to as high as 40,000 mg/L TDS.
5. Revisit all previously issued exemptions to determine if the exemptions should be rescinded based on the new criteria.

The NRDC asserts that new information has arisen since the aquifer rules were written, and that EPA must update its rules to account for increasing groundwater demand, climate change, and technological advancements for brackish groundwater desalination.

Class II injection wells are essential to oil and natural gas production. Primary uses of injection wells include the injection of water, steam, and CO_2 to conduct enhanced oil recovery (EOR) and water disposal associated with oil and natural gas production in areas where no other disposal options are available. Without the ability to utilize Class II injection wells, American oil and natural gas production in many areas of the country would be dramatically curtailed or shut in altogether.

Under the SDWA, Class II injection activity is allowed in areas where the groundwater quality exceeds the USDW threshold of 10,000 TDS mg/L. Injection where the groundwater contains less than 10,000 TDS mg/L is only allowed in areas that have been formally exempted pursuant to a state application that has been submitted to EPA. EPA maintains general criteria that an application must demonstrate in order to qualify for an exemption, not the least of which is that the area proposed for exemption does not supply drinking water, and cannot feasibly be expected to economically provide drinking water. The existing criteria require extensive geologic and water quality information to be submitted in order to gain approval and provide significant flexibility to allow the state and federal agencies involved in the review to consider site specific factors that are relevant to the decision.

The proposed actions sought in the NRDC petition could potentially halt the ability of states to permit new injection wells until EPA conducts a multiyear rulemaking proceeding. Development of new water disposal and EOR wells would likely be placed in limbo while EPA reviews the status of areas that have been exempt for more than thirty years and considers whether to revise the definition of a USDW. State regulatory agencies in areas where the groundwater exceeds 10,000 mg/L TDS could prospectively be forced to spend considerable resources preparing applications to go through the federal exemption process as a condition of maintaining operations they had already permitted and were actively regulating.

In California, the third largest producing area in the country, EPA Region 9 directed the California Division of Oil, Gas & Geothermal Resources (DOGGR) in 2010 to update the exemption boundaries for more than 50 oil fields throughout the state. More than 25 applications have already been prepared using the current approved criteria and are being submitted to EPA for review. New drilling in many areas of the state has been put on hold for the past several years while the scientific based applications have been under development. Approval of the NRDC petition would essentially nullify the significant resources that have been expended in an effort to comply with EPA's directive and would extend the drilling moratorium in perpetuity.

Abrupt agency approval of the application would also likely lead to a significant reduction in drilling new production wells. Without adequate injection well capacity to handle produced water, some producers may be forced to suspend capital investments in new production wells. Many areas with oil and natural gas resources would likely be precluded from development altogether if the resources require EOR operations or the operators do not have access to reasonable methods of produced water disposal and management. Major oil and gas producing states impacted by this review include: California, Utah, Colorado, Wyoming, North Dakota, Texas, Louisiana, Ohio, and Oklahoma.

The lack of confirmed impacts to groundwater from oil and natural gas related injection activities validates that the historic criteria used by EPA has served to protect areas with true groundwater supply potential. Furthermore, the existing criteria provide the state regulatory agencies significant flexibility in making decisions to protect local groundwater resources while facilitating new oil and natural gas development.

The goal of the NRDC petition is to dramatically advance the "Keep It in the Ground" agenda by imposing a multiyear moratorium on a critical type of well that is essential to supporting existing and new oil and natural gas operations.

Small Business Implications

Class II injection wells are the widely available technology to manage produced water or to use produced water for secondary recovery in conventional wells in most producing formations. Loss of access to Class II wells for small businesses would prevent the continued operation of many low producing wells.

Recommendations

EPA retains considerable discretion under the APA on how quickly it must respond to petitions.

It can choose to grant approval and initiate a rulemaking proceeding, or deny the petition outright. Since there are no timing restrictions that guide EPA's response, the agency can act promptly and without significant public notice, or it can delay its response for an extended period. EPA is not required to hold a public comment period before it takes action on a petition.

EPA should act to deny the NRDC petition and continue to use the current process to determine aquifer exemptions. Additionally, EPA regions should be directed to work closely with states to facilitate their determinations.

STATE DELEGATION

Major federal environmental laws hinge on an effective federal-state relationship. At the heart of this relationship is the distribution of responsibilities between the governments. When Congress created its federal environmental laws, it recognized the joint realities that most states already operated environmental regulatory programs and that the Congress would never create nor fund a competing federal program. Consequently, it turned to the approach of partnering with the states through the process of delegating federal authority to the states. As a result, the federal government's role is principally creating national standards, authorizing state management of federal law, stewarding state regulatory actions, addressing interstate and international issues and funding for research and state support. State regulators are the primary creators for the regulatory requirements that permit and managing environmental emissions and discharges.

This balance creates an effective system that is predictable. However, it functions best when each partner stays within its fundamental responsibilities. Unfortunately, for American oil and natural gas production, over the past 8 years, federal agencies aggressively acted to expand the scope of regulation to provide pathways for federal action in spite of state regulations.

This effort creates unnecessary conflict with states. States have effectively managed the environment within their borders and have crafted regulatory systems that reflect their specific circumstances. EPA cannot, through national regulations, create the flexibility necessary address these differing situations. Additionally, EPA has initiated enforcement actions that have attempted to usurp the regulatory roles of states – actions that have not been justified.

For industry, confronting different regulatory demands from states and the federal government is both costly and confusing – exposing them to possible penalties that are out of their control. Industry is prepared and committed to meeting its environmental management responsibilities, but it needs certainty and it seeks the most cost effective approach to action.

Expanded delegation of federal authority to states is the straightforward path to improve this situation. However, EPA needs to recognize that much of the delegation process was conducted decades ago when federal laws were initially passed. Consequently, EPA needs to determine if the current delegation process is still workable. State regulatory programs are different now with a mature understanding of how to effectively regulate. In the past, EPA has put limits on delegation based on its understanding of the regulatory processes at the time; these structural constraints need to be examined and revised if appropriate – actions that should be taken in conjunction with the states.

Funding is another key factor. State budgets face similar constraints faced by the federal budget. However, states will not be positioned to undertake greater delegated responsibilities without adequate funds. EPA must address this need.

Small Business Implications

By their nature, regulatory burdens are always more difficult for small businesses. In this case, the burdens of multiple state and federal permits, of state and federal regulatory compliance, of duplicative state and federal reporting need to be recognized and minimized.

Recommendations

EPA needs to expand and enhance delegation of regulatory authority to states. It needs to eliminate barriers that may exist.

The Trump Administration needs to work with Congress to assure that adequate funding is provided to states to encourage delegation.

ENFORCEMENT

Without question, compliance with environmental regulations is a clear and certain responsibility of every oil and natural gas producer. Equally certain, regulators have the responsibility to assure that compliance occurs and to enforce compliance when necessary. Two challenges, then, are what entities should enforce and how should that enforcement take place.

State agencies are the primary enforcers of their regulations. However, EPA can exert its enforcement authority when it concludes that a state is not adequately managing a federally delegated program or where there is no state authority – for example, under a Federal Implementation Plan under the CAA or where the state has not been delegated authority.

From our perspective, EPA needs to thoroughly review and revise its federal enforcement process. It needs to create an enforcement program that treats the regulated community with fairness, respect and dignity. It needs to eliminate the use of excessive threatening tactics, egregious fine proposals and enforcement to compel regulation where EPA has no authority.

For example, in North Dakota EPA Enforcement initiated an aggressive action related to the storage tank component of Subpart OOOO. It targeted a private company, rather than a publicly held company. It threatened the company with fines that would exceed the company's value and possibly the entire assets of the family owners. Its basis for action relied on interpretations of the regulation that differed from those provided by EPA's technical staff. And, of course, it then used these threats not only to compel operational changes to the storage vessels, but to demand additional actions beyond the scope of the regulations. This type of egregious enforcement must be halted.

Small Business Implications

Small businesses should not be the convenient targets of the federal litigators' unlimited budgets. EPA's Enforcement Office should not target small business companies where it hopes to use its essentially unlimited power to subjugate them to meet its interpretation of regulations.

Recommendations

Unfortunately, Keep It in the Ground environmentalists clamor to the press and plaster the internet with allegations that any change to scrutinize the current enforcement approach at the Agency is tantamount to an abdication of federal responsibilities. In reality, the current EPA enforcement program appears to be too loosely managed. As a result, EPA Regional Offices and each Headquarters Program office can initiate and pursue enforcement actions without any coordinated standards. EPA needs to create a consistent set of standards and expectations.

Any federal agency can unleash an abusive enforcement program and justify it as necessary to make sure the regulated community is held accountable. But, the regulated community is overwhelming committed to complying with its regulatory burden. It, after all, lives in the communities where it operates. And, it must meet its shareholders' expectations as a good corporate citizen.

EPA needs to craft an enforcement program that assures that federal laws are being properly implemented, but not one that seeks to use its authority to seek actions beyond the scope of the law. It needs to be forceful but fair and respectful. It needs to be an enforcement program that is accountable.

COST EFFECTIVENESS CALCULATIONS

A key component of regulatory development involves the determination of the costs and benefits of regulations. Clearly, any such process is an open invitation for abuse. Costs can be understated; benefits can be overstated. History indicates that both have been done to produce a result that falls within whatever target has been set.

Recently, one of the regulatory arenas where obvious abuse has occurred is the development of benefits to justify climate change related regulations. The most notable area of abuse is the creation of the Social Cost of Carbon, Nitrous Oxide and Methane. The generation of these costs were cloistered and obscure. The process did not allow for the openness needed to have any confidence in its application. And, in its use, agencies were able to apply it to conveniently adjust estimates when needed. The March 28, 2017, Executive Order eliminating Social Cost use was entirely appropriate to bring certainty and confidence to the regulatory review process.

Yet, other calculations – less visible, less obviously manipulated – were similarly abused in regulatory analyses. For example, in the justification for Subpart OOOOa, EPA based its recovered methane basis and its economic evaluations on natural gas prices that were wholly inaccurate. Specifically, EPA used a methane value of $4.00/mcf. For a producer to receive $4.00/mcf for its gas sales, the market price would have to be about $5.33/mcf to account for royalties and fees. Currently, natural gas prices are ranging around $3.00/mcf, meaning that the producer would be getting about $2.25/mcf. This significant overestimate of the value of natural gas roughly doubles the benefits of methane regulations without the imposition of Social Cost benefits. EPA never brought its cost effectiveness calculations into the realistic framework of actual natural gas prices.

Recommendations

As EPA reconsiders regulation of oil and natural gas production facilities, it needs to fully recognize that the economic calculations regarding cost effectiveness should be revised.

CONCLUSION

These issues are examples of issues that directly affect independent producers from EPA regulations and potential regulations. The fundamental problem, however, is EPA's failure to do the work to understand American oil and natural gas production. A former EPA Administrator was reported as stating:

> EPA's learning this industry right now because it is not an industry we regulate. We've just gotten into regulation of this so there's a lot of hundreds of thousands of small sources and EPA does not generally have a relationship with this industry as we do other sectors that we've regulated for frankly decades. But we are learning.

Unfortunately, EPA has been regulating before it has learned. Unlike most industries, oil and natural gas production begins to decline soon after it starts. The industry is comprised of large and small businesses with most low producing wells operated by small businesses. Regulations that might be cost effective when a well is new will not be after it declines and certainly when it is a low producing well. Imposing regulations designed for new sources on existing sources will almost certainly threaten their existence.

EPA has the authority to subcategorize its regulatory actions. For example, it has the capacity to distinguish between large and small sources – or to exclude small sources altogether – or to delay regulation of small sources until it has the information to understand how to develop small source cost effective regulations. But, it has chosen not to utilize this flexibility – at least in its recent actions.

EPA needs to recast its thinking. It needs to develop the understanding of the industry that it does not have.

IPAA appreciates the opportunity to submit these comments. If additional information is needed, please contact Lee Fuller at lfuller@ipaa.org or 202-857-4722.

Sincerely,

Lee O. Fuller

Lee O. Fuller
Executive Vice President

INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

APPENDIX 1

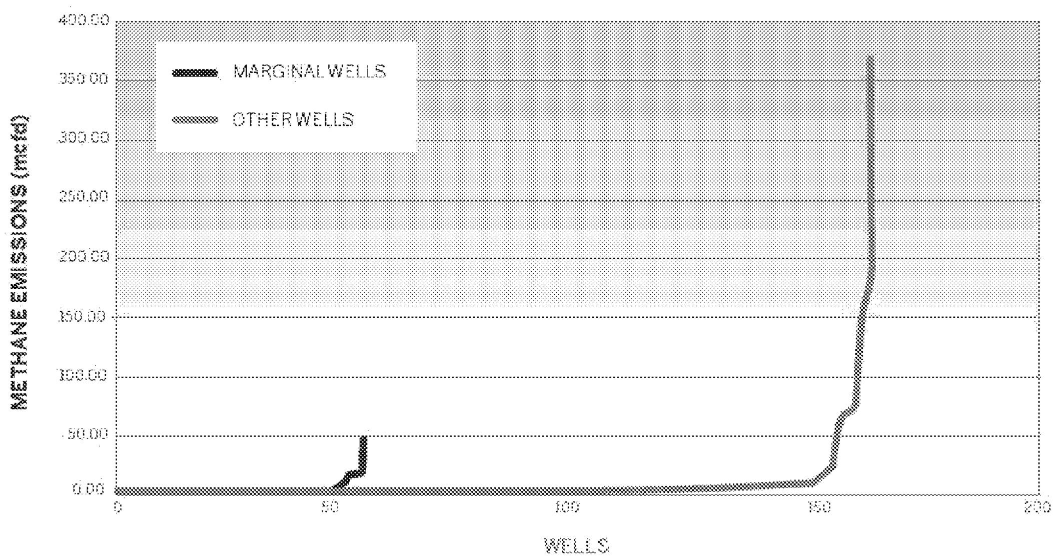
Manipulating Data to Create the Illusion That Low Producing Wells Are "Super-Emitters"

This document addresses data manipulation issues in the environmentalist study submitted to the rulemaking proposal for Subpart OOOOa to distort the role of low producing wells regarding methane emissions. This study was then characterized as the basis for removing the low producing well exclusion for the Subpart OOOOa fugitive emissions program initially proposed by the Environmental Protection Agency (EPA).

Background

Initially, it is important to understand that this study used data from a number of different studies to create its arguments. All of the underlying studies generated their data by driving vehicles with samplers downwind of production sites, hunting for methane plumes. None of them used samples taken on the production site. This creates two issues. First, it measures everything emitted at the site – fugitive emissions and permitted vents. Second, the data are collected over minutes – maybe over an hour – but not over a day. The data in the study are presented as if they were daily emissions but the studies merely scale up hourly estimates. Consequently, an emission that might occur for several hours, but not the full day, would be overstated.

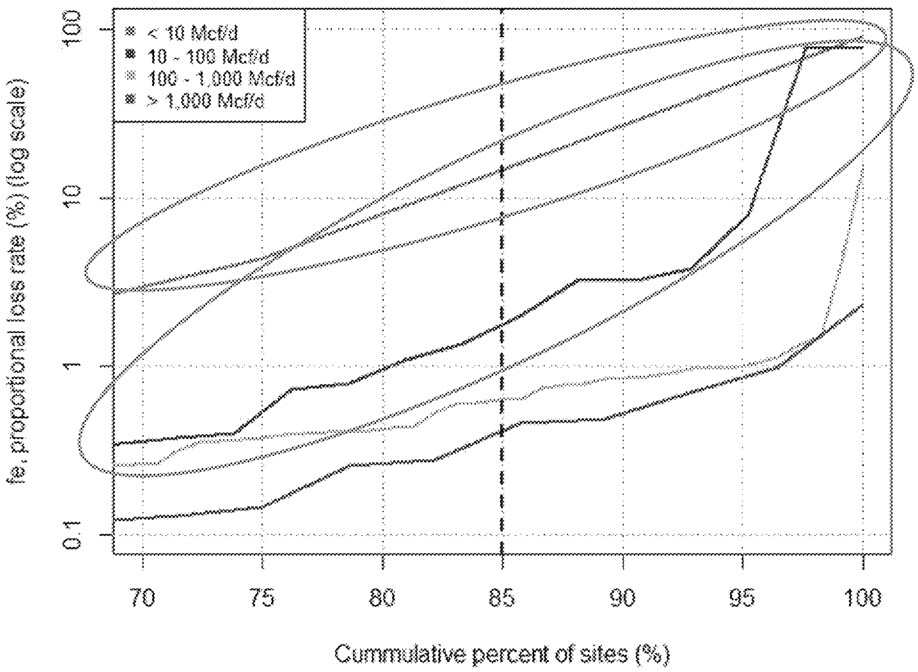
Before turning further to describe the submitted study, it is useful to look at the same data using a direct graph of emissions. In this graph, marginal wells are those with production volumes of 90 mcfd or less.



This graph is consistent with information from other studies showing that a small portion of wells have an emission profile for some reason with high emissions and most wells have really low emissions. Importantly, it also clearly shows that marginal wells – low producing wells in the context of the regulation – have far smaller emissions. But, since this graph is using the same data as the study, it could also be overstating emissions because of scaling short term emissions to a daily amount.

With this background, turning to the presentation of the same material in the study demonstrates how it was manipulated.

Below is the graphic used to present the data. It would suggest that the worst emitting operations – the "super-emitters" – are the smallest wells (the orange line and the blue line, circled in green). Having directly plotted this data, the obvious issue is how such a result can occur.



It is a busy and confusing graph – it's intended to be. The study uses data analysis tricks to create the appearance that marginal wells are "super-emitters".

First, it shows emissions as a percentage of production rather than actual emissions. Thus, one mcf emitted out of ten mcf produced is 10 percent, but 50 mcf emitted out of 1000 mcf produced is 5 percent. As a result, it skews the perception of the data to imply that low producing wells are large emitters when they are not.

Second, its production volumes are really sales volumes, not the amount extracted from the wellhead. Consequently, a "proportional loss rate" of 50 percent would be the calculated loss divided by the volume sold. If the percentage of loss were calculated based on extracted volumes, the 50 percent "proportional loss rate" would drop to 33 percent because the loss would be added to the sales volume to obtain the extracted volume.

Third, it only shows data from the 70th percentile of information. This excludes all of the virtually zero emissions that dominate the data.

Fourth, it uses a logarithmic scale to present the data. One of the reasons to use logarithmic scales is to flatten curves to make them look more like straight lines.

These observations can be made without conducting an intense investigation of the study. They are obviously intended to contort data to create a specific result. Yet, with all the investigative power at EPA, with all of the research work EPA has conducted, EPA took this contrived study at face value to make its determination to remove the low producing well exclusion in the Subpart OOOOa regulations. That decision – particularly void of any opportunity for public review – should not be allowed to stand.

IPAA
INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

AXPC American Exploration & Production Council

December 4, 2015

Gina McCarthy
Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, D.C. 20460

VIA ELECTRONIC MAIL

Re: Comments for Three Regulatory Proposals issued September 18, 2015:

1) **Oil and Natural Gas Sector: Emission Standards for New and Modified Sources (80 Fed. Reg. 56,593)**

2) **Release of Draft Control Technique Guidelines for the Oil and Natural Gas Industry (80 Fed. Reg. 56,577)**

3) **Source Determination for Certain Emission Units in the Oil and Natural Gas Sector (80 Fed. Reg. 56,579)**

Dear Administrator McCarthy:

These comments are filed on behalf of the Independent Petroleum Association of America (IPAA) and the American Exploration and Production Council (AXPC) (collectively, IPAA/AXPC).[1]

IPAA represents the thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts, that will most directly be impacted by the U.S. Environmental Protection Agency (EPA) policy decisions to regulate methane directly from the oil and natural gas sector. Independent producers develop about 95 percent of American oil and gas wells, produce 54 percent of American oil, and produce 85 percent of American natural gas. Historically, independent producers have invested over 150 percent of their cash flow back into domestic oil and natural gas development to find and produce more American energy. IPAA is dedicated to ensuring a strong, viable domestic oil and natural gas industry, recognizing that an adequate and secure supply of energy is essential to the national economy.

AXPC is a national trade association representing 30 of America's largest and most active independent oil and natural gas exploration and production companies. AXPC members are "independent" in that their operations are limited to exploration for and production of oil and natural gas. Moreover, our members operate autonomously, unlike their fully integrated counterparts, which operate in additional segments of the energy business, such as downstream refining and marketing. AXPC members are leaders in developing and applying innovative and

[1] For ease of reference, these comments include an Acronym Index, attached hereto as "Attachment A."

advanced technologies necessary to explore for and produce oil and natural gas, both offshore and onshore, from unconventional sources.

Additionally, they are joined by the American Association of Professional Landmen (AAPL), the Association of Energy Service Companies (AESC), the International Association of Drilling Contractors (IADC), the International Association of Geophysical Contractors (IAGC), the National Stripper Well Association (NSWA), the Petroleum Equipment & Services Association (PESA), the US Oil & Gas Association (USOGA), and the following organizations:

Arkansas Independent Producers and Royalty Owners Association
California Independent Petroleum Association
Coalbed Methane Association of Alabama
Colorado Oil & Gas Association
East Texas Producers & Royalty Owners Association
Eastern Kansas Oil & Gas Association
Florida Independent Petroleum Association
Idaho Petroleum Council
Illinois Oil & Gas Association
Independent Oil & Gas Association of New York
Independent Oil & Gas Association of West Virginia
Independent Oil Producers' Agency
Independent Oil Producers Association Tri-State
Independent Petroleum Association of New Mexico
Indiana Oil & Gas Association
Kansas Independent Oil & Gas Association
Kentucky Oil & Gas Association
Louisiana Oil & Gas Association
Michigan Oil & Gas Association
Mississippi Independent Producers & Royalty Association
Montana Petroleum Association
National Association of Royalty Owners
Nebraska Independent Oil & Gas Association
New Mexico Oil & Gas Association
New York State Oil Producers Association
North Dakota Petroleum Council
Northern Montana Oil and Gas Association
Ohio Oil & Gas Association
Oklahoma Independent Petroleum Association
Panhandle Producers & Royalty Owners Association
Pennsylvania Independent Oil & Gas Association
Permian Basin Petroleum Association
Petroleum Association of Wyoming
Southeastern Ohio Oil & Gas Association
Tennessee Oil & Gas Association
Texas Alliance of Energy Producers

Texas Oil and Gas Association
Texas Independent Producers and Royalty Owners Association
Utah Petroleum Association
Virginia Oil and Gas Association
West Slope Colorado Oil & Gas Association
West Virginia Oil and Natural Gas Association

Collectively, these groups represent the thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts, that will be most significantly affected by the actions resulting from these regulatory proposals. In addition to the specific comments made herein, we support those comments submitted separately by the participants in these comments. IPAA/AXPC also endorses and supports the comments of the Western Energy Alliance (WEA) and the American Petroleum Institute (API) submitted on the proposed rules referenced above.

As an initial matter, these comments are designed to address the three aforementioned proposed regulatory actions simultaneously and will be submitted to all three dockets as all three proposals target the oil and natural gas industry, and certain responses and arguments from IPAA/AXPC are applicable to all of the proposals. Additionally, comments on all three proposals were initially due November 17, 2015. IPAA requested an extension of the 60-day comment period on October 2, 2015, due to the complexity and breadth of the proposed regulations and that certain key supporting documents were not available in the docket for public review when the EPA published the proposals in the Federal Register on September 18, 2015. In late October/early November various informed parties who had requested additional time to comment learned that they would have until December 4, 2015. On November 13, 2015, the extension was published in the Federal Register.

EXECUTIVE SUMMARY

These comments raise a number of key issues associated with EPA's proposals for Clean Air Act (CAA or Act) New Source Performance Standards (NSPS), Control Technique Guidelines (CTG) and Source Determination for oil and natural gas production facilities.

EPA justifies its proposals in the context of the Administration's Climate Action Plan with a specific target of reducing methane emissions from the oil and natural gas sectors by 40-45 percent during the time period from 2012 through 2025. However, as these comments demonstrate, EPA's proposals are unnecessary, unjustified, poorly developed and counterproductive.

First, the Administration proclaims its intent to reduce methane emissions by 40-45 percent from the oil and natural gas sectors. At the same time, it takes credit for its 2012 volatile organic chemical/methane emissions regulations in these sectors that exceed its own target. Moreover, it fails to recognize that much of the reduction it seeks has occurred since 2012 from voluntary industry actions. The oil and natural gas production sector is 1.07 percent of the national Greenhouse Gas Inventory and its methane emissions will continue to drop because of industry emissions management. Consequently, any justification for additional regulation must be thoroughly weighed based on cost effectiveness and economic consequences. EPA's proposals fail these tests.

Second, within the NSPS proposal, the most egregious element is the proposed fugitive emissions regulations that are based on purely speculative emissions reductions but, as designed, are excessively and unnecessarily burdensome. Oil and natural gas production fugitive emissions management is an emerging arena with companies and state regulatory programs still learning how best to efficiently and effectively control them. Several states are currently implementing programs; none of which parallel EPA's proposals. Experience with those state efforts demonstrates that emissions patterns result from a few high emissions sources that can be managed quickly with sustained reductions. EPA's proposal to lock in an unworkable program for at least 5 years is arbitrary and inappropriate. EPA should await the analysis of state programs to determine whether an NSPS is logical or necessary.

Third, EPA also proposed a volatile organic compound (VOC) CTG for Ozone nonattainment areas. This proposal fails to comply with the Agency's fundamental responsibility of developing Reasonably Available Control Technology (RACT). Instead, EPA largely transposes the same requirements in the 2012 NSPS and those proposed in this regulatory action from new sources to existing ones. In doing so, EPA fails to determine whether these new facility requirements are economically appropriate as CTG for existing sources on a national basis.

Fourth, by linking its CTG proposal to its Climate Action Plan, EPA fails to address the need for the CTG with regard to Ozone nonattainment. Yet, the threshold question for these regulations is whether they are necessary and appropriate for attainment of the Ozone National Ambient Air Quality Standards (NAAQS). If fact, based on EPA's analysis of the regulatory framework to attain the recently revised Ozone NAAQS, EPA demonstrates the CTG are wholly unnecessary. Prior to proposing these CTG, EPA concluded that all but a few areas of the country will meet the new Ozone NAAQS by 2025 using national, federal regulatory requirements. Consequently, for these areas, the proposed CTG are excessive regulations. For the remaining enduring Ozone nonattainment areas, if there are oil and natural gas production operations that need to be addressed, they can be managed through local determinations of Reasonably Available Control Measures (RACM) and do not require CTG.

Fifth, because these CTG are unnecessary, their likely impact will be the inappropriate restriction of economic growth in Ozone nonattainment areas. Given that EPA has concluded that Ozone NAAQS attainment will be achieved without these CTG, these CTG will remove emissions that could be used as CAA required new source offsets. Therefore, they would unnecessarily impede economic growth that would otherwise occur.

Sixth, in its proposal to address Source Determination for oil and natural gas production facilities, EPA should recognize that new facilities should be based on a narrow definition that hones closely to the approach EPA has used under the National Emissions Standards for Hazardous Air Pollutants (NESHAP) program. Where there are issues regarding scope, the source determination should be based on the sites being contiguous in addition to sharing the same Standard Industrial Classification (SIC) Code and being under common control.

These comments will expand on the issues raised above and other more specific ones. Ultimately, however, IPAA/AXPC argues that EPA's NSPS and CTG proposals must be withdrawn, reconsidered and revised to be consistent with the Administration's own Climate Action Plan objectives and its assessment of the capability of the nation to meet the revised Ozone NAAQS. To do otherwise would arbitrarily impose excessive regulation on the oil and natural gas setoff for no purpose other than to expand the already burdensome federal regulatory program.

I. EPA's Additional New Source Performance Standards for the Exploration and Production Segment and Control Technique Guidelines for Existing Sources are Unnecessary and Misplaced.

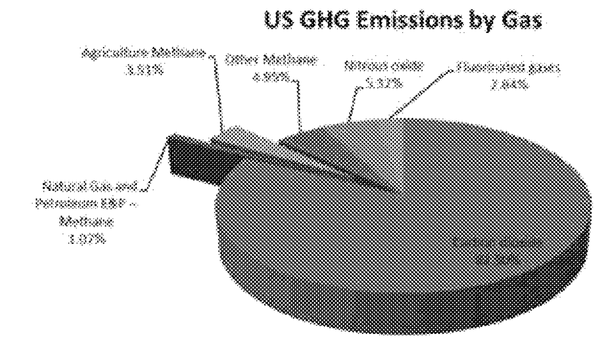
EPA's proposed NSPS targeting methane emissions from the exploration and production segment of the oil and natural gas sector are unnecessary, unwarranted, and wasteful – not only to those subject to the regulations but to the state and federal regulators who must implement the rules if EPA does not change its course. Similarly, proposing essentially the same set of controls on existing sources in nonattainment areas (and ozone transport regions) using the proposed CTG with no additional economic justification/cost-benefit analysis is one more indication that EPA is rushing to judgment with its latest salvo of regulations. In April 2014, EPA acknowledged the lack of knowledge to regulate a variety of sources and implemented a White Paper process that sought additional technical information on a variety of sources.[2] Industry raised numerous concerns regarding EPA's lack of data regarding emissions from these sources and the cost/effectiveness of controls from these sources. Nonetheless, EPA proceeded headlong to promulgate its methane NSPS – relying heavily on the Regulatory Impact Analysis (RIA) from the VOC NSPS promulgated in 2012. The methane regulations need to "stand on their own" and be justified on their own, not simply as an "add-on" to the VOC NSPS.

These regulations will have a serious negative economic impact on American oil and natural gas production while providing marginal environmental benefit beyond the regulations EPA promulgated in 2012 to regulate VOCs from essentially the same set of production and exploration emission sources.[3] To understand the full impact, it is essential to put the entire issue in perspective.

[2] U.S. Environmental Protection Agency, Section on Oil and Natural Gas Air Pollution Standards, *Methane*, *available at* http://www3.epa.gov/airquality/oilandgas/methane.html.

[3] Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 77 Fed. Reg. 49,490 (Aug. 16, 2012).

From 2008 through 2013, U.S. shale gas production grew 400 percent,[4] while methane emissions have declined 13.3 percent. According to 2013 EPA Greenhouse Gas (GHG) Reporting data, methane emissions from oil and natural gas exploration and production are 1.07 percent of total U.S. GHG emissions. Further reductions will occur because of "green" or "reduced emission completions" that are being phased-in through the 2012 regulations.[5] According to EPA's latest GHG Reporting Program: "[In 2013] reported methane emissions from petroleum and natural gas systems sector have decreased by 12 percent since 2011, with the largest reductions coming from hydraulically fractured natural gas wells, which have decreased by 73 percent during that period. EPA expects to see further emission reductions as the agency's 2012 standards for the oil and gas industry become fully implemented."[6] These reductions are remarkable, given that a major component of the 2012 standards, the reduced emission completion requirements, only became effective January 1, 2015.



In January 2015, the Administration announced its intent to initiate rulemaking to further reduce methane emissions from oil and natural gas systems, including the production sector.[7] Specifically, it announced a target of a 40-45 percent reduction in 2012 emissions by 2025. For the production and exploration segment of the oil and natural gas sector, additional regulations are unnecessary. As the Administration observed in its announcement:

> In 2012, the Environmental Protection Agency (EPA) laid a foundation for further action when it issued standards for volatile organic compounds (VOC) from the oil and natural gas industry. These standards, when fully implemented, are expected to reduce 190,000 to 290,000 tons of VOC and decrease methane

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[4] U.S. Energy Information Administration, *available at* http://www.eia.gov/dnav/ng/hist/res_epg0_r5302_nus_bcfa.htm.

[5] In 2012, EPA finalized a Clean Air Act (CAA or Act) Section 111(b) NSPS targeting VOCs emissions from hydraulically fractured natural gas wells. This rulemaking also reduces methane emissions as co-benefit. Methane and VOCs are emitted from oil and natural gas production facilities at the same time from the same equipment. Consequently, reducing one also reduces the other. The effects of the 2012 NSPS are still unfolding.

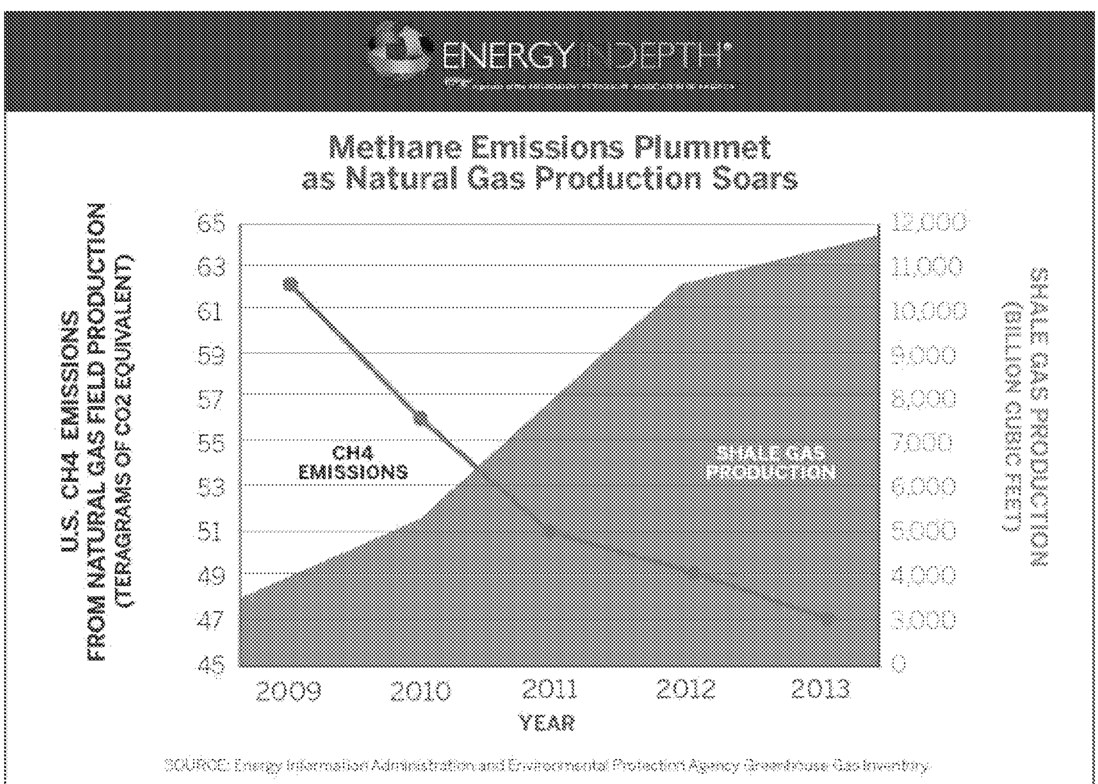
[6] Requirements for reduced emission completions on natural gas wells were promulgated in August 2012 but did not become effective until January 1, 2015. Oil and Natural Gas Sector: Reconsideration of Additional Provisions of New Source Performance Standards, 79 Fed. Reg. 79,018 (Dec. 31, 2014) (codified at 40 C.F.R. pt. 60).

[7] Press Release, The White House, Fact Sheet: Administration Takes Steps Forward on Climate Action Plan by Announcing Actions to Cut Methane Emissions (Jan. 14, 2015), *available at* https://www.whitehouse.gov/the-press-office/2015/01/14/fact-sheet-administration-takes-steps-forward-climate-action-plan-anno-1.

emissions in an amount equivalent to 33 million tons of carbon pollution per year.[8]

Over 99 percent of the EPA projected reductions occur from the exploration and production sector. In 2013, exploration and production emissions of methane were 71 million tons of CO_2 equivalent. Consequently, by EPA's own numbers, the 2012 NSPS regulations will reduce emissions by 46 percent. This reduction exceeds the emissions target percentage of the production sector of the oil and natural gas industry.

EPA attempts to argue that its regulations are needed because methane emissions "are projected to increase by about 25 percent over the next decade if additional steps are not taken to reduce emissions from this rapidly growing industry."[9] Yet, this statement is wholly inconsistent with the experience over the past several years in the exploration and production sector of the industry. This segment has demonstrated that growth in production not only provides more clean-burning, GHG-reducing product, it has been done while reducing methane emissions as the following graphic shows:



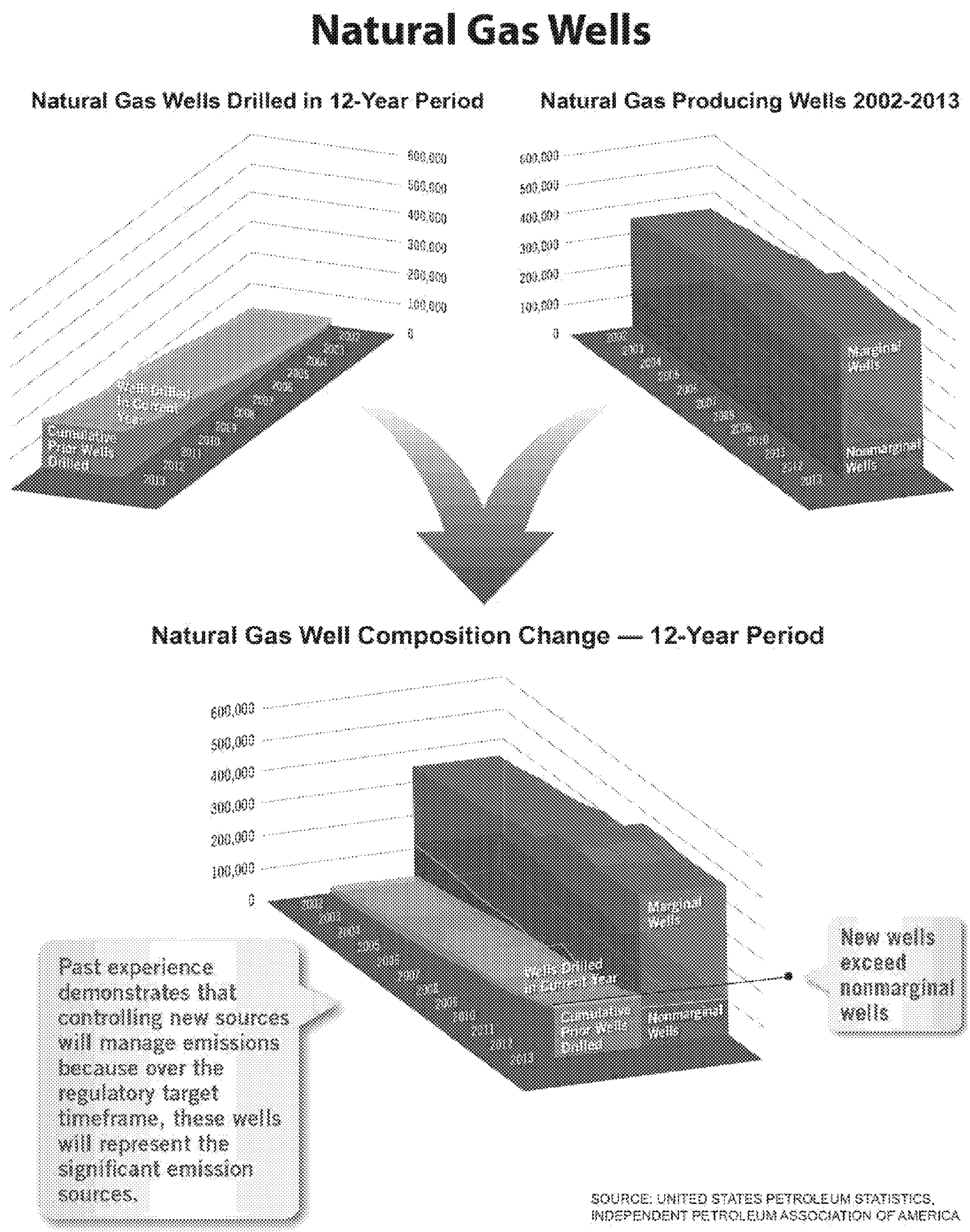
[8] *Id.*

[9] U.S. Environmental Protection Agency, Fact Sheet: EPA's Strategy for Reducing Methane and Ozone-Forming Pollution from the Oil and Natural Gas Industry (Jan. 14, 2015), *available at* https://www.whitehouse.gov/the-press-office/2015/01/14/fact-sheet-administration-takes-steps-forward-climate-action-plan-anno-1.

Significantly, these reductions in methane emissions have occurred prior to full implementation of the 2012 NSPS.

Moreover, because of the nature of oil and natural gas production, the application of controls on new sources will achieve the Administration's objectives without the need to create extensive existing source regulations. Oil and natural gas production operations differ from other types of manufacturing. After the period of initial production, wells begin to decline – generally referred to as the "production decline curve." And as the production of the well declines, its ability to emit VOCs and methane into the atmosphere also declines. Emissions from these older wells will be a smaller portion of the 1.07 percent of emissions, yet EPA's decision to regulate methane directly under Section 111(b) of the CAA and proposed CTG subjects tens of thousands of existing wells to regulation. IPAA/AXPC questions the cost-effectiveness of the proposed requirements to existing sources. The regulatory burden on state and federal regulators of exposing hundreds of thousands of existing sources is completely overlooked in EPA's proposal.

The declining nature of oil and natural gas wells also differentiates the exploration and production segment of the oil and natural gas sector from other segments further downstream where emissions remain fairly constant overtime. Ultimately, the production from the "new" wells declines to the point where they become "marginal" wells. These are defined as wells that produce 15 barrels/day of oil or less and 90 mscf/d or less of natural gas. Currently, there are over 1.1 million oil and natural gas wells in the United States; approximately 760,000 are marginal wells. However, these small individual wells account for about 20 percent of U.S. oil production and 13 percent of its natural gas production. Consequently, unlike manufacturing facilities where new facilities do not replace existing ones, in the oil and natural gas production industry, the implementation of technology on new wells will rapidly result in its application across the breadth of the industry as new wells become the predominant source of emissions for the industry. This can be understood by looking at past experience as shown in the graphs below:



As this graphic demonstrates, after 12 years wells subject to the new source regulatory requirements will dominate the production of natural gas, and the remaining wells will be marginal wells with minimal incremental emissions beyond the emissions from sources already subject to regulation. The cost associated with reducing those incremental emissions will be greater than the cost of implementing controls on new or modified sources and will likely make many of the marginal wells uneconomic, causing them to be shut in/abandoned. The opportunity

Gina McCarthy
December 4, 2015
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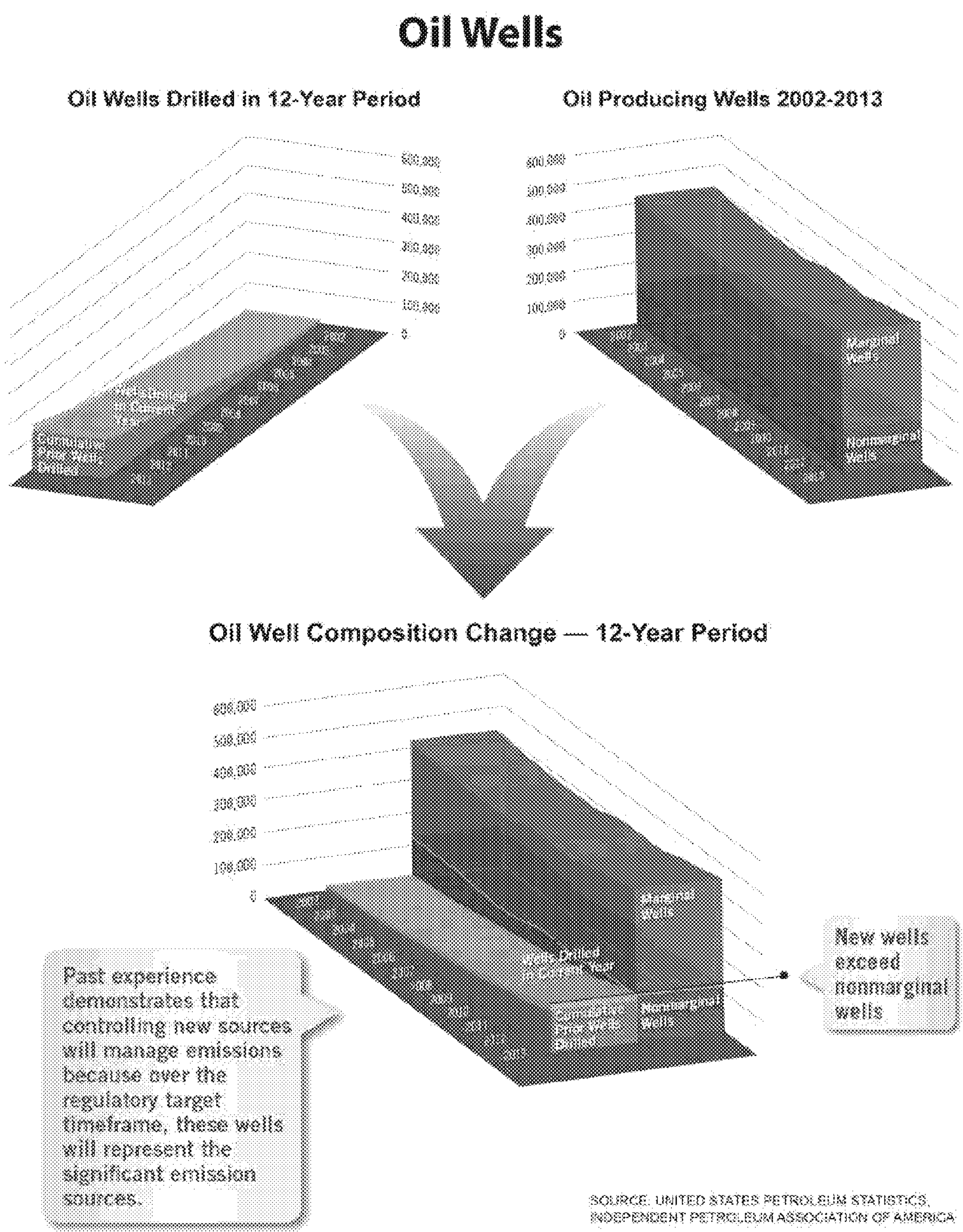
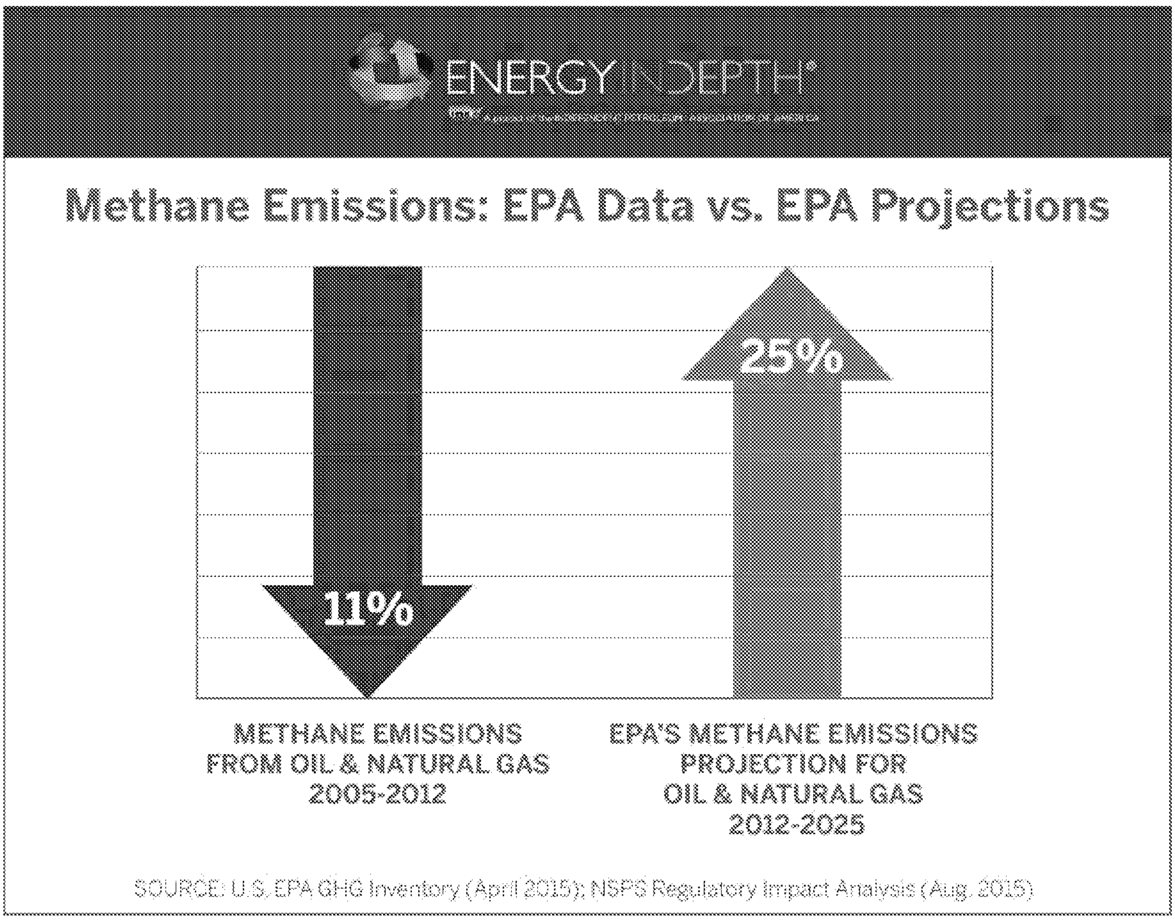
cost or value of that last production is not offset by the minimal emissions reductions achieved by regulating existing sources.

A similar pattern exists for oil wells as shown below:



While this analysis is based on past experience, if it were expanded to a 20-year period, it would show a similar trend and demonstrate that the use of new source regulations are more than adequate to address the Administration's interest in reducing methane emissions from the oil and natural gas sector, in general, and the exploration and production segment, in particular. EPA has failed to adequately account for and justify subjecting existing exploration and production sources to regulation under Section 111 of the CAA or through the CTG.

As Energy In Depth (a research, education, and public outreach campaign supported by IPAA) recently reported, EPA's assumptions regarding methane emissions from the oil and natural gas industry are not supported by EPA's own data.

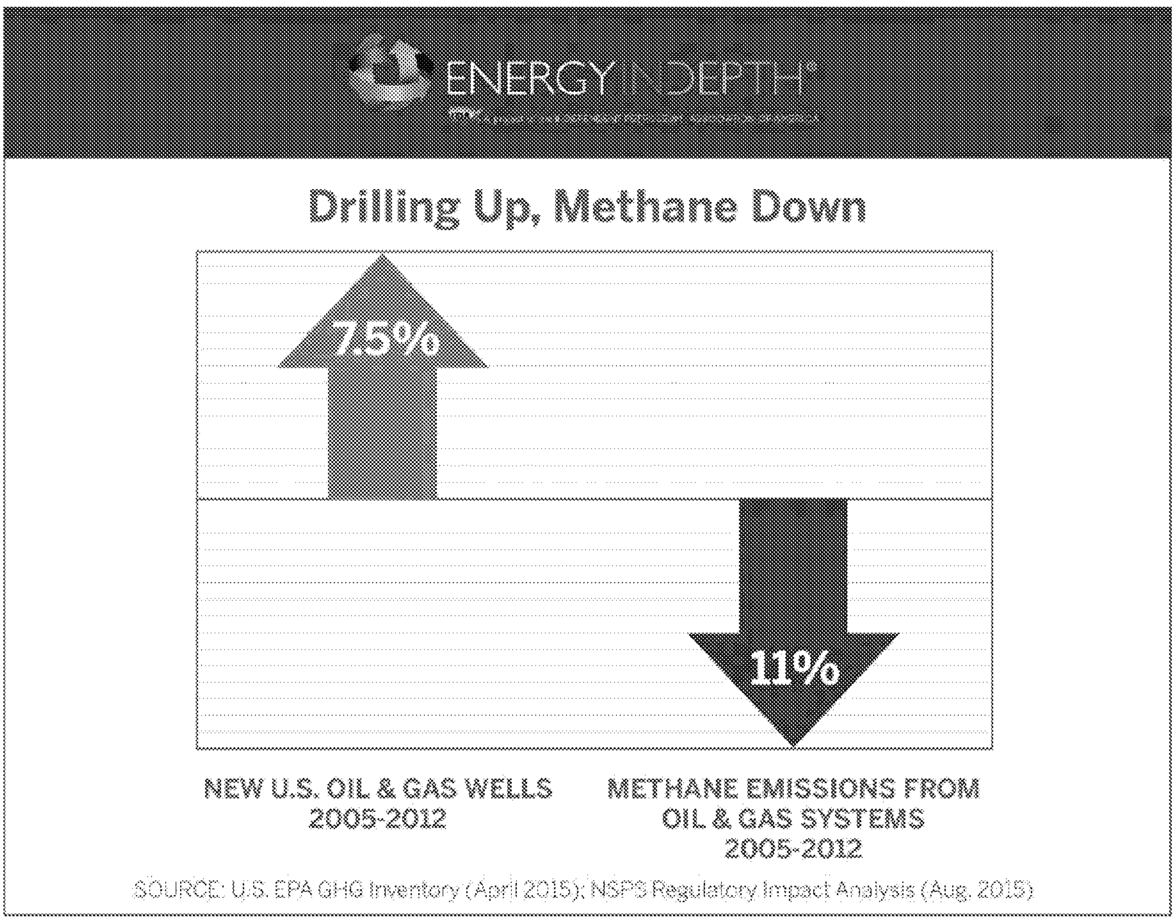


More specifically, Energy In Depth found:

- EPA projects methane emissions from the oil and natural gas sector will increase over the next decade, but **methane emissions from that sector have declined by more than 22 million metric tons** since 2005.
- Over the past decade, the United States added more than 86,000 new wells, during which **methane emissions from petroleum and natural gas systems fell by 11 percent**.
- EPA's flawed assumptions on methane emissions raise questions about the agency's cost-benefit calculation, and EPA could be **underestimating engineering costs by more than $10 million**.

- The EPA could also be **overstating the climate benefits of the rule**, since methane emissions may be significantly lower than EPA's projections.[10]

As discussed below, EPA's economic justification for it proposed regulations is problematic. But even the past does not support EPA's fundamental assumption that more drilling means more emissions:



EPA has projected that an increase in oil and natural gas activity will result in a 25 percent increase in methane emissions. But since 2005, methane emissions from U.S. oil and natural gas systems have fallen by a greater percentage than the number of new wells drilled.

IPAA/AXPC has repeatedly told EPA that additional regulation is not needed. Market forces drive the industry to minimize emissions. Unlike certain "products" in other industries with "emissions" that are a by-product or negative externality associated with the production, the "emission" of concern to EPA is the very product this industry brings to the market.

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[10] Steve Everley, *New EPA Methane Regulations Based on Flawed Emissions Assumptions* (2015), Energy in Depth, *available at* http://energyindepth.org/national/epa-methane-regulations-flawed-emissions-assumptions/. IPAA/AXPC incorporate by reference the entire Energy In Depth article as part of its comments.

II. The Industry's Recent Past is Not Its Prologue – Therefore EPA's Proposed Regulations are Not Justified

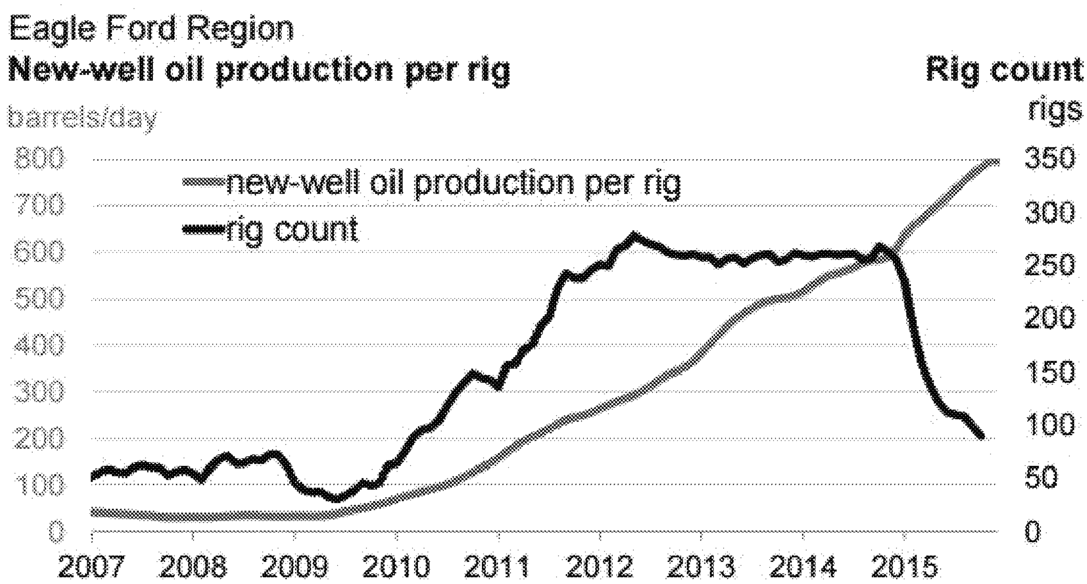
EPA justifies its proposed regulations in large part on the last 10 years of growth in the American oil and natural gas industry – perhaps the most dynamic and rapid growth period in the history of the industry:

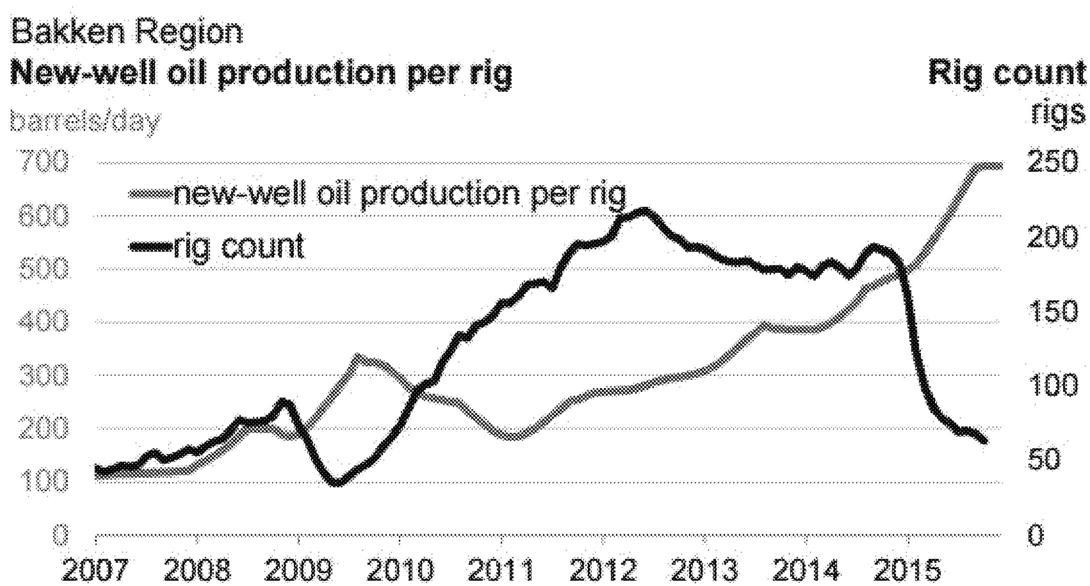
> The EPA has projected affected facilities using a combination of historical data from the U.S. GHG Inventory, and projected activity levels, taken from the Energy Information Administration (EIA's) Annual Energy Outlook (AEO). The EPA derived typical counts for new compressors, pneumatic controllers, and pneumatic pumps by averaging the year-to-year increases over the past ten years in the Inventory. New and modified hydraulically fractured oil well completions and well sites are based on projections and growth rates consistent with the drilling activity in the 2014 Annual Energy Outlook."[11]

As much as the oil and natural gas sector would like to see that growth rate continue to 2025, it simply will not happen, and the past few years illustrate the cyclical nature of the industry. The price of oil and natural gas has plummeted unlike EPA's hypothetical projections. Operators react quickly to market forces and in many shale plays very few wells are being drilled. For many small, independent operators in various plays, they have not drilled a well in 3 or more years – yet EPA is justifying the cost of the proposed regulations on the most rapid expansion in the history of the industry. The following charts from a recent article by Energy In Depth,[12] based on EIA data, clearly illustrate the impact of market forces:

[11] Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector, EPA-452/R-15-002 (Aug. 2015) at 3-9.

[12] Steve Everley, *New EPA Methane Regulations Based on Flawed Emissions Assumptions* (2015), Energy in Depth, *available at* http://energyindepth.org/national/epa-methane-regulations-flawed-emissions-assumptions/.





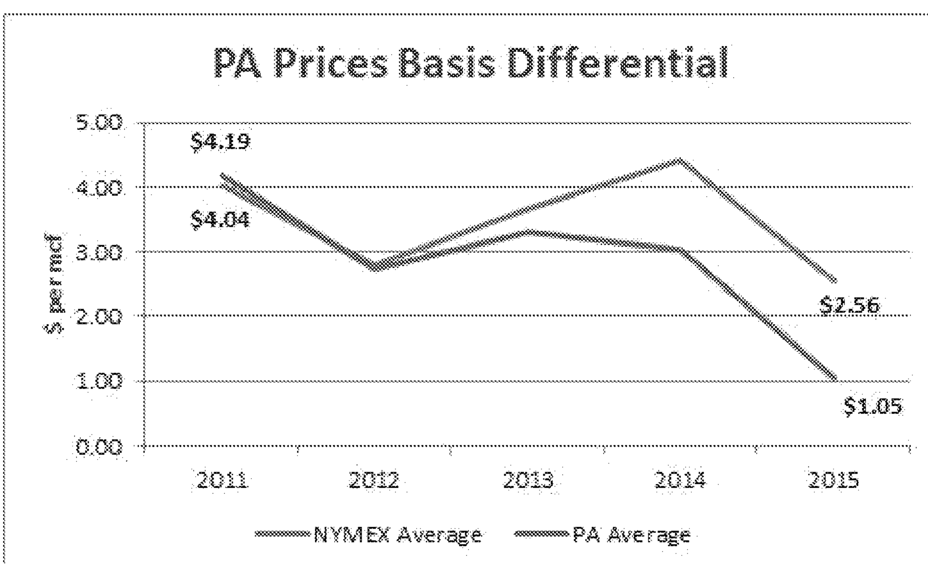
SOURCE: U.S. Energy Information Administration

EPA's cost-effectiveness analysis of the proposed regulations "applies the monetary value of the saved natural gas as an offset to the" cost of the proposed controls.[13] EPA then valued 1,000 standard cubic feet (Mcf) of natural gas at $4.00 for the RIA/cost-effectiveness analysis. The $4/Mcf assumption was based on EIA's 2014 Annual Energy Outlook forecasted

[13] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,617(Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60).

wellhead prices for the lower 48 states in 2020 ($4.46) and in 2025 ($5.06). EPA considered the $4/Mcf to be "conservative"[14] – presumably because of the predicted value of natural gas in 2020 and 2025. There are numerous problems with EPA assumptions. First, the New York Mercantile Exchange (NYMEX) settlement price for natural gas in October 2015 was $2.56 – 36% lower than EPA's assumed value. EPA has repeatedly indicated that it will finalize the proposed methane NSPS by the summer of 2016, and no financial institution is predicting a dramatic increase in natural gas prices between now and then. For those subject to regulations that come into effect within the next year, EPA's "conservative" estimate of $4/Mcf based on government estimates of what natural gas will cost in 2020 and 2025 is meaningless. IPAA/AXPC appreciates that the "benefit" or value of the natural gas saved by the proposed regulations occurs over the life of the well; however, the emissions from any well are heavily "front-loaded" – with the greatest production, and thus potential emissions, occurring the first few years of the well's life – long before 2020 or 2025. Smaller independents, many conventional well operators, and operators of wells that are marginally economical will not be able to weather the storm until natural gas reaches EPA's conservative value of $4/Mcf. Wells will not be drilled or will be shut in prematurely, and other companies will simply go out of business because of EPA's erroneous assumption on the price of natural gas. EPA's cost-effectiveness analysis for all proposed controls should be based on a price of natural gas that: a) more accurately reflects the price of natural gas when controls will need to be implemented, and b) accounts for the "front loading" of emissions when the price of natural gas is much lower than the $4/Mcf assumed by EPA.

EPA's assumption of $4/Mcf natural gas also fails to acknowledge or account for significant regional differences in the price of natural gas. A review of the wellhead price of natural gas in Pennsylvania provides but one of the many dramatic price variations.



[14] *Id.*

The chart above tracks the PA Price versus NYMEX average prices for the past 4 years and is current through October 2015. The "PA Price" is based on a weighted average of the Dominion South, Leidy, and Tennessee Zone 4 prices reported by Platt's *Inside FERC*. The separation of prices in Pennsylvania from the national index price is driven in large part by the lack of takeaway pipeline capacity and sheer volume of natural gas. The regional variation in price is not accounted for in EPA's cost-effectiveness analysis. Consequently EPA's inflated valuation of the price of natural gas will disproportionally impact certain regions of the country where local or regional factors result in prices that are significantly lower than the national average. EPA's cost-effectiveness analysis must take such significant regional price fluctuations into consideration when evaluating control options.

EPA is proposing regulations so fast that even it cannot keep up with the changing assumptions. Part of EPA's assumption of $4/Mcf natural gas was based on EPA's proposed Clean Power Plan.[15] However, EPA's final Clean Power Plan changed its "assumptions," and EPA now "believes" renewables will play a greater role in the country's future energy mix and natural gas prices may not reach $4/Mcf until after 2030 – well beyond the EPA's analysis for the proposed methane NSPS which ends in 2025. As Energy In Depth points out, the changing assumptions have a dramatic impact on the industry:

> According to EPA data compiled by the American Wind Energy Association (AWEA), a heavier reliance on renewables could result in natural gas prices that are at least 12 percent lower than what would be expected under EPA's base case projection [for the Clean Power Plan]. EPA also acknowledges in its RIA that a $1/Mcf change in price of natural gas translates to as much as a $19 million difference in its cost estimate. In other words, if natural gas prices averaged $3/Mcf instead of $4/Mcf, EPA could be overestimating revenue by roughly 24 percent. Based on the current 2012-2015 average natural gas spot price of $3.44/Mcf, EPA would be overestimating revenue by about $10.6 million. Under the "high renewables" scenario in the Clean Power Plan, which would depress natural gas prices even further, EPA's overestimate would be even higher.
>
> The additional costs could be devastating for an industry already suffering from a market downturn in commodity prices. An analysis by Oppenheimer & Co., for example, already found that EPA's methane rule could wipe out smaller drillers across the United States.[16]

In addition to failing to account for the changed assumptions for the price of oil and natural gas as a result of the Clean Power Plan, EPA has made no effort to account for the impact associated with proposed Ozone NAAQS. For EPA to evaluate the proposed impact of the proposed methane NSPS in a vacuum, ignoring its own significant regulatory initiatives that will have serious impacts on the price of oil and natural gas, as well as the number of entities that will be

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[15] Steve Everley, *New EPA Methane Regulations Based on Flawed Emissions Assumptions* (2015), Energy in Depth, *available at* http://energyindepth.org/national/epa-methane-regulations-flawed-emissions-assumptions/.

[16] *Id.*

subject to controls, is arbitrary and capricious. Every mutual fund and investment opportunity contains the standard disclaimer along the lines of – "past performance cannot guarantee future results." The oil and natural gas industry is no different – even without EPA impacting market forces with multiple regulatory disruptions.

III. Now is Not the Time to Introduce a New Model to Justify EPA's Proposed Rules.

The benefits of the proposed rule are estimated using the social cost of methane (SC-CH_4), which has been derived from the approach the United States Government (USG) uses for estimating the social cost of carbon (SCC). However, unlike the USG's SCC which has undergone formal public comment and review, EPA's selected value for SC-CH_4 in this proposed rulemaking is arbitrarily taken from one scientific report[17] that attempts to find an equivalent SC-CH_4 from the SCC, and for which EPA only requested a "peer review" not formal public review and comment. The "peer review" was only concluded in 2014 and discussed as the basis for EPA's cost-effectiveness analysis for the first time in the RIA.[18] The model has not been evaluated by Office of Management and Budget. Providing industry a mere 60 days (plus 17) to evaluate and comment on what amounts to "new math" is inadequate. Also, the selected value of SC-CH_4 used for the Benefit-Cost Analysis in the RIA is based on an arbitrarily selected discount rate of 3 percent, which also was not proposed for public review and comment before being used to justify this proposed rulemaking.[19] Even though now EPA belatedly "seeks comments on the use of these directly modeled estimates, from the peer reviewed literature, for the social cost of non-CO_2 GHGs . . .,"[20] such a request, after EPA has already used its arbitrary value for SC-CH_4 to justify methane emissions controls on numerous methane emissions sources, is arbitrary and capricious. The only proper and legal way for EPA to apply a SC-CH_4 value to methane emissions reductions for proposed rulemakings is to publish a proposal for a SC-CH_4 value (based on scientific evidence and its arguments for a certain discount rate), take public comments on that proposed value, and finalize the value for future rulemakings. Otherwise, EPA can arbitrarily use one value of SC-CH_4 to justify controls on methane emissions from one industrial sector source and then turn-around later and use some other arbitrary value for another industrial sector source, all presumably justified by taking comment on the arbitrary value already used to justify the proposed regulations.

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[17] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,655 (Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60).

[18] Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector, EPA-452/R-15-002 (Aug. 2015).

[19] Exacerbating the arbitrary nature of the 3% discount rate for benefits, EPA inconsistently and inappropriately selected a 7% discount rate for the cost to industry. EPA's unjustified use of different discount rates arbitrarily and capriciously overstates the benefits compared to the costs.

[20] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,656 (Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60).

IV. Overarching Comments Particular to the Proposed NSPS for Methane, Subpart OOOOa.

In Sections V and VI of the preamble to the proposed NSPS, EPA dedicates considerable verbiage attempting to justify the need and its legal authority to regulate methane from sources in the oil and natural gas sector. IPAA/AXPC disagrees with both the need and EPA's authority to regulate methane for the reasons set forth below.

EPA's interest in regulating methane is clearly a political decision rather than an environmentally driven decision. Its genesis can be easily seen in the strident demands from anti-fossil energy groups with agendas not to manage industrial emissions but to prevent the development of oil and natural gas. Groups like the Sierra Club have policies that are clear:

> There are no "clean" fossil fuels. The Sierra Club is committed to eliminating the use of fossil fuels, including coal, natural gas and oil, as soon as possible . . . Methane released via extraction and transport is 86 times more potent as a greenhouse gas than CO_2 over a 20-year time frame. The climate-disruption impacts from methane and carbon dioxide emitted by extraction, transport and burning clearly point to the urgent need of keeping fossil fuels in the ground.[21]

This group, along with others, made their demands known to the EPA in multiple meetings and letters, including a December 2013 letter stating the following:

> We commend EPA for updating its VOCs performance standards for this industry in 2012, but the job is far from finished. While some reductions in methane emissions will be achieved as a co-benefit of these 2012 rules, many emission sources are not adequately addressed, such as the vast network of equipment that was installed before those rules went into effect. EPA needs to take immediate steps to produce regulations to directly reduce methane pollution from new and existing equipment from this industry.[22]

Once demanded, the issue of direct methane regulation became the pivot point for development of the current regulatory proposals. As discussed below, the drive for direct methane regulations for the oil and natural gas sector is driven by atmospherics and philosophy, not science or increased environmental benefit.

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[21] *Sierra Club to Big Oil: There are no 'clean' fossil fuels*. Sierra Club (Apr. 21, 2015) *available at* http://angeles.sierraclub.org/news/blog/2015/04/sierra_club_big_oil_there_are_no_clean_fossil_fuels.

[22] Earthworks, *et al*. Interior Secretary Jewell, EPA Administrator McCarty to Curb Methane Emissions from Oil and Gas Industry, Earthworks (Dec. 5, 2013) *available at* https://www.earthworksaction.org/library/detail/open_letter_to_interior_secretary_jewell_epa_administrator_mccarthy_to_curb#.VmHY97Eo74Y.

In reality, EPA was forced to propose regulations to satisfy a political agenda that is governed more by what "we [EPA] believe that the industry can bear . . . and survive."[23] EPA's decision to promulgate methane standards from the exploration and production segment of the oil and natural gas sector is arbitrary and capricious. EPA states that it "believe[s] it is important to regulate methane from the oil and gas sources already regulated for VOC emissions to provide more consistency across the category . . . ."[24] Yet in the very same sentence EPA admits "that the best system of emission reductions (BSER) for methane for all these sources is the same as the BSER for VOC."[25] EPA continues that the BSER for the previously unregulated sources is the same for VOCs and methane. Simply put, the controls on the targeted emissions sources to reduce VOCs are the same as the controls to reduce methane – no more, no less. The "gain" – according to EPA – of adding yet another Subpart of regulations to the already extensive 40 C.F.R Part 60 is "consistency." What EPA chooses to ignore in its preamble discussion is the inevitable "loss" or cost to the industry associated with the regulation of existing sources under Section 111(d).

EPA is silent as to its "beliefs" on whether the industry can "survive" the cost and burden of regulation of existing sources under Section 111(d). This silence is notable and troubling. Clearly, since EPA demonstrates that the technologies used to regulate methane emissions are identical to those for VOC emissions, EPA's choice to expand its regulations to directly regulate methane can only be interpreted as opening a potential pathway to Section 111(d) regulations as the anti-fossil energy organizations demanded. And, while EPA fails to even mention Section 111(d), it must certainly know – based on the demand that existing methane sources must be regulated – that it will face efforts to force such regulation. EPA will surely respond that it will conduct the necessary cost-benefit analysis when it is "forced" to promulgate existing source standards under Section 111(d). Without debating the legalities as to EPA's duties under Section 111(d), this Administration has demonstrated time and time again its propensity to feign resistance to non-governmental organizations' (NGO) "demands" and enter into consent decrees with unreasonable short time periods to promulgate regulations. The irony is that EPA's rationale assumes that the underlying Section 111(b) regulations were necessary in the first place. What has the environment gained (above the benefits gained from VOCs) from regulating methane emissions from exploration and production directly? Nothing. EPA has admitted it. The controls are the same – equally efficient at controlling VOCs and methane. The cost? EPA relies heavily on its original cost-effectiveness analysis for the Subpart OOOO VOC regulations finalized in 2012 and engages in additional analysis discussed in Section VIII of the preamble, concluding that the proposed controls "for methane" are also cost-effective. But nowhere does EPA take into account the cost to the industry associated with the regulations that will likely be forced upon existing sources in this source category. Despite all of the complicated calculations and analyses, the simple fact remains that the controls for VOCs and methane from the targeted sources are the same. There is no demonstrated "need" or unique benefit associated with an additional set of standards specifically for methane. The true cost of the proposed methane

[23] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,629 (Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60)

[24] *Id.* at 56,595.

[25] *Id.*

regulations is incomplete and unknown without considering the cost associated with regulating existing sources under Section 111(d).

"Consistency across the category" is an insufficient justification. Historically, EPA has tailored new source performance standards to subcategories or segments within a larger, overarching category. One needs to look no farther than Subpart D and its progeny for Steam Generating Units or Subpart E for Municipal Waste Combustors. EPA has shown it can be very creative in tailoring requirements to subcategories or segments within a listed category. Since the Administration first hinted at regulating methane directly from the exploration and production segment, IPAA/AXPC has advocated that such direct regulation was unnecessary, as the controls for VOCs were exactly the same as for methane. EPA acknowledged as much in Section VII in the preamble and stated "[w]e anticipate that these stakeholders will express their views during the comment period."[26] IPAA/AXPC questions the appropriateness of EPA's decision to essentially ignore a central premise of two federal trade associations that represent approximately 54% of oil and 85% of natural gas exploration and production capacity of this country. Is it appropriate for IPAA/AXPC to guess as to EPA's reasoning and justification? Much of EPA's 67-page preamble is dedicated to justifying its legal basis for regulating methane directly and the cost-effectiveness of the proposed controls. It fails to address in any meaningful way why it is necessary or justified to promulgate methane standards from the exploration and production segment. EPA's justification boils down to: 1) EPA assumes it is has the legal authority to do so; 2) EPA has placed a high value on "consistency" within the source category; and 3) EPA "believes" the industry can "survive." EPA is on much stronger legal footing addressing segments or subcategories differently within the oil and natural gas sector than asserting it does not need a separate endangerment finding for methane. EPA's insistence, without explanation, on promulgating methane standards for exploration and production sources, when the controls are exactly the same, needlessly increases the regulatory burden on everyone – the regulated and the regulator. IPAA/AXPC should not have to guess until the rule is finalized and potentially litigate an issue that has been clearly articulated to EPA, the Small Business Administration, and the Office of Management and Budget long before the rule was even proposed.

In Section V and VI, EPA indicates it is responding to and granting a Petition for Reconsideration associated with the 2012 NSPS Subpart OOOO for VOCs which requested the promulgation of NSPS for methane. The key elements outlined as EPA's reasoning for granting reconsideration are:

- "the wealth of additional information now available to us . . ."[27]
- "[t]he oil and natural gas industry is one of the largest emitters of methane, a GHG with a global warming potential more than 25 times greater than that of carbon dioxide."[28]

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[26] *Id.* at 56,609.

[27] *Id.* at 56,599.

[28] *Id.*

- "because the EPA is not listing a new source category in this rule, the EPA is not required to make a new endangerment finding with regard to oil and natural gas source category in order to establish standards of performance for the methane from those sources."[29]
- "a number of major scientific assessments have been released that improve understanding of the climate system and strengthen the case that GHGs endanger public health and welfare for current and future generations."[30]

EPA then dedicates approximately 10 pages of the preamble to defending their position that a separate endangerment finding strictly for methane is not needed (and backfilling in case they are wrong), making the case for global climate change from GHGs, and presenting various charts on U.S. methane emissions. Unlike the remaining sections of the preamble (approximately 55 pages), in which EPA seeks specific comments on particular issues at least 50 different times, EPA did not seek comment once in Sections V and VI.

While IPAA/AXPC has not attempted to take issue with or refute every inaccuracy or assertion contained within these sections of the preamble, EPA's key elements are addressed briefly below:

- IPAA/AXPC agrees there is a wealth of additional information – much of it taking issue with anthropogenic global warming. A cursory review of the website Watts Up With That, http://wattsupwiththat.com/, reveals the science is not "settled" as EPA would have one believe.
- While EPA alleges that the oil and natural gas sector is one of the "largest emitters of methane", EPA's own numbers illustrate that in 2013, the oil and natural gas sector accounted for 2.22% of the Total U.S. GHG Inventory.[31] And as stated earlier, the exploration and production segment is only 1.07% of that 2.22%. The oft-quoted greenhouse gas multiplier is subject to manipulation based on the timeframe used to make the carbon dioxide comparison, and the "legacy warming from fugitive methane is minuscule compared to that of carbon dioxide."[32]
- The adequacy of EPA's endangerment finding is far from settled and will certainly be subject to legal challenge upon final promulgation of this rule if EPA persists with its intention to regulate methane directly.[33]
- In supporting its claim that EPA better understands climate change, it cites the Intergovernmental Panel on Climate Change's (IPCC) 2013-2014 Fifth Assessment Report (AR5). Many of these "citations" or statements to support EPA's position are

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[29] *Id.* at 56,601.

[30] *Id.* at 56602.

[31] *Id.* at 56,608.

[32] Elizabeth A. Muller and Richard A. Muller, *The Facts About Fugitive Methane*, Centre for Policy Studies (Oct. 2015) *available at* http://www.cps.org.uk/files/reports/original/151022155129-TheFactsofFugitiveMethane.pdf.

[33] David Yaussy and Elizabeth Turgeon. *Unringing the Bell: Time for EPA to Reconsider Its Greenhouse Gas Endangerment Finding*, 116 W.Va. L. Rev. 1007 (2014).

from the Summary for Policy Makers, which was written by the policy makers, not the scientists who authored the report.[34] Judith Curry, former Chair of the School of Earth and Atmospheric Sciences at the Georgia Institute of Technology, evaluated and commented on the AR5, not the Summary for Policy Makers, and noted various factors that evidence a weakening of the case for anthropogenic global warming:

  - Lack of warming since 1998 and growing discrepancies with climate model projections
  - Evidence of decreased climate sensitivity to increases in CO_2
  - Evidence that sea level rise from 1920-1950 is of the same magnitude in 1993-2012
  - Increasing Antarctic sea ice extent
  - Low confidence in attributing extreme weather events to anthropogenic global warming.[35]

- EPA also relies heavily on the U.S. Global Change Research Program's (USGCRP) 2014 National Climate Assessment, Climate Change Impacts in the United States (NCA3), to support its alleged climate change impacts – ranging from decreased Artic summer sea ice to increased sea levels to drier/more intense storms, as well as greater impact to children and the elderly.
  - Studies not cited by EPA demonstrate no significant changes or deviations from cyclical patterns in the quantity of ice.[36]
  - As to the frequency and intensity of storms, other studies not cited by EPA raise questions regarding storm predictability: "October marks a continuation of a record-long major hurricane (Category 3 or stronger) landfall drought in the United States. The last major hurricane to make landfall in the U.S. was Wilma on October 24, 2005. This major hurricane drought surpassed the length of the eight-years from 1861-1868 when no major hurricane struck the United States' coast. On average, a major hurricane makes landfall in the U.S. about once every three years. The reliable record of landfalling hurricanes in the U.S. dates back to 1851."[37] "The bar [see footnote] charts

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[34] Wim Rost, *IPCC ≠ Science ↔ IPCC = Government*, Watts Up With That (Nov. 29, 2015) *available at* http://wattsupwiththat.com/2015/11/29/ipcc-science-ipcc-government/.

[35] Judith Curry, *IPCC AR5 Weakens the Case for AGW*, Climate Etc. (Jan 6, 2014) *available at* http://judithcurry.com/2014/01/06/ipcc-ar5-weakens-the-case-for-agw/.

[36] http://ocean.dmi.dk/arctic/plots/icecover/icecover_current_new.png; http://nsidc.org/data/seaice_index/images/daily_images/S_stddev_timeseries.png

[37] National Oceanic and Atmospheric Administration , National Centers for Environmental Information, State of the Climate: Hurricanes and Tropical Storms for October 2015 (Nov. 2015) *available at* https://www.ncdc.noaa.gov/sotc/tropical-cyclones/201510. While other ranking metrics for hurricane's are being developed, the National Hurricane Center for the National Oceanic and Atmospheric Administration and EPA continue to regularly rely on an cite to the Saffir-Simpson Hurricane Wind Scale to compare the potential impacts of hurricanes.

> below indicate there has been little trend in the frequency of the stronger tornadoes over the past 55 years."[38]

The title of Section V of the preamble is "Why is the EPA Proposing to Establish Methane Standards in the Oil and Natural Gas NSPS?" EPA's stated concerns are ostensibly laudable. However, nothing set forth in Section V or Section VI of the preamble justifies or necessitates separate methane NSPS from the exploration and production sector.

A. Consistent with the Clean Air Act, State Programs Should Control

The CAA is structured such that states should have primacy and be primarily responsible for compliance with the requirements of the Act. Many of the states with the most active shale plays have implemented state regulations to address many of the emissions sources targeted in the proposed Subpart OOOOa regulations. States with state permitting programs and/or State Implementation Plans (SIPs) that contain limits on sources that are legally and practically enforceable should be deemed sufficient for overlapping and duplicative requirements in Subpart OOOO and the finalized version of Subpart OOOOa. EPA should defer to existing state regulations to the greatest extent possible to deem compliance with state regulations on the same sources as constituting compliance with the final Subpart OOOOa regulations. Duplication and inconsistency between state and federal regulations simply add to the cost of compliance with little to no additional benefit to the environment. To the extent EPA does not allow for such provisions, EPA should demonstrate that the duplicate or "more stringent" regulations that EPA is promulgating are incrementally cost-effective: meaning that the cost associated with the duplicative or inconsistent federal control requirement is cost-effective based on the incremental environmental benefit above the state regulation already in place or deem compliance with the state regulations as compliance with Subpart OOOOa. EPA must justify with an *incremental* cost and benefit analysis any proposal to impose additional federal regulations that it deems more stringent than existing state regulations.

B. Fugitive Emissions at Well Sites and Compressor Stations

Managing fugitive emissions or "leaks" from the oil and natural gas sector appeals to common sense. Leaks associated with natural gas operations represent safety concerns, negative impacts to the environment, and are wasteful from an economic standpoint. The industry has relied on audio/visual/olfactory (AVO) inspections for many years, and only recently has the industry focused considerable attention on technological advances to detect leaks. It is an emerging process – both in terms of technology and methodology (regulatory and corporate management). EPA's preamble bears this fact out with the number of specific requests for "comment" on the leak detection aspect of the proposal. IPAA/AXPC supports, in concept, the ability to satisfy the leak detection and repair (LDAR) requirements of the proposal with an appropriate "corporate fugitive monitoring plan," but a 60-day comment period (plus a random 17 days halfway through the comment period) is not enough time to create and implement such a

[38] National Oceanic and Atmospheric Administration, National Centers for Environmental Information, Historical Records and Trends, *available at* https://www.ncdc.noaa.gov/climate-information/extreme-events/us-tornado-climatology/trends.

program. Additionally, recent data and studies demonstrate that production fugitive emissions are characterized by a few sources ("fat tails") representing the overwhelming majority of emissions.[39]

A handful of states are taking the lead on creating regulatory frameworks, each of which is different, and none of which follows the proposed EPA framework. Experience with the state programs is indicating that correction of fat tail emissions results in effective management of fugitive sources and, once corrected, the need for full-blown inspections/surveys more often than an annual frequency is unjustified. Even the states with the most aggressive LDAR programs are not focused on quantifying the total amount of methane "saved." The very nature of fugitive emissions makes it very difficult to quantify how much gas is being "saved." It is not as simple as a single point source with consistent flow where one can easily measure the emissions before and after controls are "bolted on" a stack or emission point. The component count at most facilities is likely in the hundreds to thousands, with only a very small percentage of the components leaking. For those that are leaking, the quantity of gas leaking varies considerably. Nonetheless, EPA crunched some numbers in a hypothetical world and assigned some value to the natural gas that is saved. In reality, very few companies will realize any change in the sales meter pre- and post-LDAR. The savings are largely illusionary to the average operator. The value of the natural gas "saved" through the LDAR programs is highly speculative. In addition, EPA did not account for the size of the facility when estimating the percent savings. EPA's percentage saved calculations are based on Colorado's regulations and related data. Colorado's 80% reduction, which EPA adopts, is based on monthly inspections for facilities with less than 50 tons per year. EPA assumes, with no additional support, that their proposed regulations can achieve an 80% reduction from quarterly inspections for all facilities, regardless of size. IPAA/AXPC questions the validity of EPA's cost-effectiveness analysis for its proposed LDAR regulations.

EPA should withdraw the proposed LDAR NSPS because it has not been developed based on the emerging experiences with fugitive emissions management programs, it locks in a technology approach that may be cost ineffective as experience with state programs evolves, and it would stifle the development of better approaches. Instead, EPA should work with states to learn from their programs and provide for a flexible voluntary fugitive emissions program in the Methane Challenge that would build a basis for a cost-effective NSPS in the future, if one is needed. At a minimum, implementation of any program should be delayed and EPA should work with industry to establish the necessary elements of a corporate fugitive monitoring plan that companies could adopt and customize to meet their particular needs while satisfying EPA's LDAR requirements. This performance-based approach would be the most effective and efficient.

Other than the handful of companies that provide the optical gas imaging (OGI) technology, industry is united in its position that EPA should not select or dictate the technology for detecting leaks. The concept behind NSPS is setting a performance standard that must be

[39] David T. Allen, *et al*. 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 (Aug. 19, 2013) *available at* http://www.pnas.org/content/110/44/17768.

met – not dictating a particular technology. Dictating a particular technology stifles innovation. There are approximately a half dozen or more additional technologies/techniques that are being marketed and/or developed including, but not limited to: tunable diode laser absorption spectroscopy; 3-channel non-dispersive gas correlation infrared spectrometer; mid-infrared laser-based differential absorption light detection and ranging; simultaneous-view gas correlation passive infrared radiometer; acoustic gas lead detectors; and remote methane leak detectors. These are in addition to the existing Method 21 procedure that some companies find workable and preferable. The need and motivation to "build a better mouse trap" will cease to exist if EPA dictates the technology, and there is no reason for EPA to select one technology.

OGI/forward looking infrared (FLIR) technology suffers from numerous limitations. Perhaps most importantly, it is not inherently safe – if not used properly on site, it could cause an explosion. Additionally, the results of the camera, the "pictures", are difficult to interpret and subject to misinterpretation, e.g., what appears to be a leak could simply be a heat plume. These problems are exacerbated in windy and/or cold conditions that are prevalent in a number of the shale plays. The technology is prohibitively expensive to smaller operators, and there is a limited supply of qualified service providers that can afford the camera. Even for the larger companies, at approximately $120,000 a camera, there will be a limited supply. For companies with diverse geographic locations, it will be difficult to comply with the short survey timeframes set forth in the proposal. The proposed regulations also require survey pictures to contain GPS coordinates. Some of the cameras do not have that function, thus requiring another device to comply with the regulations. Finally, the OGI technology is not a quantitative tool – it is not capable of determining how much natural gas is leaking.

As discussed above, a number of states are taking the lead on LDAR programs and are learning how to effectively and efficiently implement controls and administer surveys. Despite repeated requests by IPAA during the Small Business Advocacy Review Panel process and other trade association requests for EPA's proposal to be consistent with and not duplicative of existing state LDAR programs, EPA's proposal runs roughshod over existing state programs. Inconsistencies and duplication in the proposed regulations and existing programs are burdensome, inefficient and costly – especially to small entities and independent operators. IPAA/AXPC specifically incorporates by reference the comments on the NSPS proposal of Anadarko which highlight the inconsistencies between the proposed Subpart OOOOa and existing regulations in Colorado and Pennsylvania. EPA's proposed regulations essentially punish states and operators within those states that proactively moved to address fugitive admissions. Such an approach does not make for sound policy. States with existing programs should be deemed sufficient, and compliance with the state program should be deemed as compliance with the finalized federal program. This is not a new concept in the context of EPA's NSPS for the oil and natural gas industry, and EPA should revise the proposed regulations to model the exemption for storage vessels in Subpart OOOO and deem legally and practically enforceable state LDAR programs to suffice for the proposed federal regulations. Such revisions would greatly reduce the regulatory burden for sources located in states that have proactively addressed fugitive emissions from the oil and gas sector. To the extent a party (whether EPA or a third party) believes an existing state program is inadequate, the burden should be placed on the entity making the allegation, and EPA should establish a process to address the complaint.

Additionally, consistent with the CAA, the state programs should control, and EPA should implement procedures in the final regulations for states to submit for approval a state-based LDAR program that is deemed sufficient to satisfy EPA's final LDAR requirements.

Another issue advocated by IPAA/AXPC and/or member companies prior to publication of the proposed rule was to *not* base LDAR requirements on arbitrary component count or percentage of components leaking at a given site – yet that is exactly what EPA proposed. EPA suggests that its proposal, which bases the frequency of surveys on the percentage of leaking components, provides an "incentive" for companies to be more vigilant in their identification and repair of leaks. As discussed above, the incentive to identify and repair leaks already exists, as there is a strong safety and economic incentive. EPA's proposal based on percentage of leaking components creates a recordkeeping nightmare. The regulations are less than clear as to what constitutes a "facility" in terms of where to draw the line and stop the component count. As a result of the ambiguity in the proposal, it is difficult to evaluate if EPA's assumptions on components per well count are accurate. There is tremendous variability in the number of wells and types of equipment on well sites. For EPA to base its cost effectiveness on a "model well pad" is problematic. Member companies report component counts in the hundreds to thousands of components. Such a wide range is in part, a function of lack of clarity in the regulations and also calls into question the accuracy of EPA cost-effectiveness assumptions on a model plant. If EPA persists with a percent-leaking methodology, the regulations need to be clarified on what components are to be counted and how to define the limits of the facility for the component count. EPA's own evaluation concluded that quarterly surveys of the intensity proposed are not cost-effective. Yet, if more than 3% of the components are leaking, the proposed regulations require quarterly surveys. If quarterly surveys are not cost-effective, having more than 3% of the components leaking does not somehow make the quarterly surveys become cost-effective. Additionally, there is no direct correlation between the number of leaking components and quantity of emissions, so basing the frequency on the percentage of leaking components does not necessarily mean the program will be more effective at preventing fugitive emissions. While there is no direct correlation between the number of components and quantity of emissions, the component count/percent leaking ratio directly impacts the recording keeping requirements – again with no demonstrated reduction in emissions. It is just more paperwork compliance for operators.

Furthermore, leaks are often related to some sort of malfunction and once fixed, stay fixed such that there is no need or rational basis to increase the survey frequency. As EPA discussed in the preamble, experience with the state programs demonstrates there are "gross emitters" or "super emitters" that represent a very large percentage of the overall fugitive emissions profile (consistent with the fat tail issues discussed above). Preliminary information from companies with operations in states with aggressive LDAR programs already in place indicates treating every component "equally" is an inefficient use of limited resources. This information suggests that components subjected to constant or frequent vibration (such as components associated with a compressor) are much more likely to have leaks than say, threaded connections. And in terms of total component count at a given facility, there are likely to be many more threaded connections than the components most likely to leak at the relatively few compressors. Even if it is difficult to predict "gross emitters" or "super emitters" at any given facility, the knowledge gained from sources within states with existing LDAR programs suggests that treating all components equally and basing the frequency of surveys on leaking component percentages is inefficient from an emissions reduction perspective and extremely burdensome and costly – especially to small entities. Again, more time to craft a regulatory program designed to identify and repair gross emitters would be preferred by IPAA/AXPC.

Basing the frequency of surveys on the percent of components leaking exemplifies that EPA is largely guessing at what constitutes an appropriate LDAR program. EPA should not rush to judgment and instead learn from the state programs to determine the most effective and efficient way to reduce leaks. Alternatives include a performance-based approach such as that in Wyoming, basing the survey frequency on the size of the facility or the quantity of emissions leaked or perhaps a combination of a more technology-based annual survey with periodic AVO "inspections" between annual surveys. If EPA persists with the percentage-leaking-component approach, flexibility should be built into the program that companies could commit to semi-annual surveys and not be subject to fluctuation from quarterly to annual surveys based on the number of components leaking. For some companies, the ability to plan for semi-annual reporting without the risk of quarterly monitoring would be more beneficial than the changing requirements and potential cost saving of annual surveying. However, for some smaller entities or independent operators, the ability to reduce surveys to an annual basis might be beneficial. Sources should be given the flexibility to choose. Flexibility in complying with the LDAR program will help reduce the cost and burden.

Individual components that are to be included for "fugitive" emissions monitoring must be better defined and differentiated from components that are designed to emit a certain amount of natural gas under certain circumstances. Further, components of the storage vessels, e.g., closed cover/vent/control systems, already covered under Subpart OOOO for storage vessels should not be subject to additional requirements. As some states have done, EPA should more clearly define and exclude components that are designed to release pressure for safety reasons, e.g., thief hatches and enardo valves.

Dictating a particular technology (OGI/FLIR) and then requiring the initial survey be conducted within 30 days (and repaired within 15 days) is an unreasonably tight time period – especially for smaller entities and operations with disperse and remote locations. These timeframes should be extended to 60 and 30 days, respectively. If EPA persists with the unrealistic time frames, a mechanism allowing for a "variance" on the time frames when certain circumstances exist should be built into the regulations. Even with companies with the resources to purchase a camera, their operations may be geographically dispersed or weather conditions are uncooperative such that they cannot realistically get from one location to the other. Smaller entities and some independent operators who cannot afford the dictated technology are then at the mercy of the market to comply within 30 days. Especially during the early implementation of the new rules, many sources are likely to incur enforcement/liability through no fault of their own due to an inability to purchase the technology or hire service providers with the necessary capabilities.

EPA's cost-effectiveness for the proposed LDAR program requirements is fundamentally flawed because it merely looks at the cost of conducting the survey and fails to accurately account for the increased record-keeping and reporting requirements. EPA's analysis is myopically focused on a straight up comparison of "cost-effectiveness" for semi-annual surveys versus annual and opts for semi-annual requirements because the relative cost-effectiveness is the same: $2,475 for annual versus $2,768 for annual under the single pollutant approach at the well site.[40] EPA conducted similar comparisons for the multi-pollutant approach at the well site (as well as both comparisons at a compressor station).[41] In every instance the annual survey was more cost-effective but EPA selected the semi-annual surveying because the cost/ton removed was similar. There are two problems with that philosophy. First – in selecting the semi-annual requirement, EPA basically double the cost of the requirement to industry. Second, the theoretical or modeled additional reduction in emissions is a very small percentage of the overall emission reductions associated with the proposed regulations. The additional cost associated with the annual survey requirement is substantial while the increased benefit to the environment is minimal. The additional regulatory burden will be disproportionately felt by small entities. The proposed LDAR requirements basically require all companies, regardless of size, to implement costly information systems to track and monitor compliance. For example, one of the larger, more sophisticated operators with a data management system already in place incurred an additional $10,000 in external costs associated with developing new or revised software, and an additional $37,000 associated with internal set-up costs and employee time focused on implementation. These costs were associated with complying with Colorado's LDAR program in a small gas field of 174 wells and, as indicated, were in addition to an existing management system at an estimated cost of $80,000 annually. It does not appear that costs such as these were considered in EPA's cost-effectiveness analysis. EPA's proposed requirements appear to be based on what is required at natural gas plants, and expanding that level of detail to remote, un-manned production sites is inappropriate. Such level of detail is not warranted nor has the cost been adequately justified – especially over the life of the well. The majority of the "benefit" associated with the surveying is on the initial startup of a well (or startup after modifications). It is impossible to calculate an accurate annual gas recovery rate over the life of a well site.

The new record-keeping requirements associated with the LDAR are particularly burdensome to smaller operators with limited staff. For example, the preamble provides limited to no justification for requiring the date-stamped digital photograph. If EPA retains the burdensome record-keeping requirements, companies should be allowed to keep the records on site or at a regional field office and produce them upon request. Companies should not be required to submit electronically or manually to the permitting agency. EPA requested comment on "ways to minimize recordkeeping and reporting burden." As discussed above, EPA should evaluate existing state requirements and liberally deem them sufficient for purposes of Subpart OOOOa and establish a mechanism for states to implement their own programs that supersede and satisfy Subpart OOOOa.

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[40] Oil and Natural Gas Sector: Standards for Crude Oil and Natural Gas Sector: Standards for Crude Oil and Natural Gas Facilities – Background Technical Support Document for the Proposed New Source Performance Standards 40 CFR Part 60, subpart OOOOa (Aug. 2015) (hereinafter, TSD), at Table 5-14.

[41] *Id.* at Tables 5-15, 5-17, 5-18.

IPAA/AXPC supports the limited exclusions from the LDAR requirements that EPA has proposed but requests certain clarifications and expansion of the exclusions. Excluding low production well sites – defined as the "average combined oil and natural gas production for the oil and natural gas production for the wells at the site being less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production"[42] -- is extremely helpful for small entities and smaller independent operators. IPAA/AXPC understands the 15 boe is also an "off ramp" – that is, when a well drops below 15 boe, it is no longer subject to the LDAR requirements. IPAA/AXPC requests the regulatory language be revised to indicate that when a well drops below 15 boe, based on a 30-day average production, the LDAR requirements no longer apply. EPA should provide an additional exclusion for well sites with component counts below EPA's model well site: below 548 components for gas well sites and below 135 components for oil well sites should be excluded from the LDAR requirements.[43] EPA concluded that it is not cost effective to implement the proposed LDAR requirements on sites with lower well component counts and therefore those well sites should be excluded. Such exclusion would help all producers but would have greatest benefit to small entities that are likely to have smaller well sites. IPAA/AXPC also supports EPA's proposed exclusion for well sites with extremely dry gas where only the wellhead exists and there is no "ancillary equipment." IPAA/AXPC requests clarification that a meter and drip present at the well site do not constitute "ancillary equipment." Finally, in response to an EPA request for comment, IPAA/AXPC suggests that the LDAR requirements should only apply to those components that are directly connected to the fractured, refractured, or added well and should not apply to tank batteries or other equipment off the well pad which may receive fluids from the fractured, refractured or added well.

C. Oil Well Reduced Emission Completions

As with the proposed LDAR requirements, in its rush to promulgate regulations aimed at additional sources of VOCs and methane, EPA assumed that reduced emission completions (RECs) on oil wells are essentially the "same" as RECs on natural gas wells. Unlike a natural gas well, where the price of natural gas dictates many operational decisions, the economic driver for oil wells is the price and volume of oil – not natural gas. When EPA promulgated Subpart OOOO regulations for VOCs and RECs on natural gas wells, EPA indicated it did not have enough information to determine if oil well RECs were cost-effective.[44] The cost-effectiveness of oil well RECs was also raised by EPA in the Methane "White Papers" released on April 15, 2014.[45] IPAA/AXPC and individual member companies submitted comments on EPA's oil well

[42] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,612 (Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60).

[43] TSD at Table 25-1.

[44] Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 77 Fed. Reg. 49,490 ,49516 (Aug. 16, 2012)

[45] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions and Associated Gas during Ongoing Production* (Apr. 2014), *available at* http://www3.epa.gov/airquality/oilandgas/2014papers/20140415completions.pdf.

REC White Paper - identifying concerns with the cost-effectiveness of RECs for oil wells.[46] EPA's preamble discussion in Section VII of the proposed standards for oil well RECs makes a general reference to the Technical Support Document (TSD) for the current proposal in terms of justifying its best system of emissions reduction determination, but there is no updated cost/benefit data cited in the proposal. The citations refer back to the "2012 NSPS evaluation." It appears EPA has failed to cite any new or additional information collected since the 2012 evaluation to support the cost-effectiveness of the proposed oil well REC requirements. The economics of natural gas RECs are different and do not support oil well REC requirements.

Based on the preamble discussion of undertaking of an oil well REC, EPA assumes the process is essentially the same, but this is not necessarily the case. While certain wells will have relatively clear initial and separation flowback stages like natural gas wells, there are instances where there is no separation flowback stage owing to the lack of gas or quality of gas such that operation of a separator is not feasible. On certain wells, the initial flowback stage is followed by directing the flowback immediately into the production battery. Perhaps more so than with RECs on natural gas wells, the various stages of flowback on oil wells can be difficult to clearly delineate, and the ability to utilize a separator is a function of engineering judgment. IPAA/AXPC supports the concept of identifying two stages of flowback, with no control placed on the associated gas with oil well completions during the initial flowback stage. However, there will be situations where certain oil well completions will not experience a separation flowback stage.

In the preamble discussion of the REC requirements for both subcategory 1 and subcategory 2 wells, EPA expressed a clear intention to allow for venting of emissions in lieu of combustion during periods when the flowback gas is noncombustible.[47] This intent is particularly important for completions utilizing inert gas, such as nitrogen or nitrogen foam, instead of water as the medium for the fracturing process. The inert gases present in the flowback make the gas, for a period of time, "not of salable quality" and technically infeasible. The relevant provisions of the proposed regulations at 40 C.F.R. 60.5375a(a)(3) and 40 C.F.R. 60.5375a(f)(2) should be modified at the end of the provision to allow for venting when "*it is technically infeasible due to inert gas concentration*." The addition of this phrase at the end of the current proposed language would eliminate any ambiguity as to EPA's intent.

IPAA/AXPC agrees that the feasibility of oil RECs should take into consideration the availability of gathering lines and that it is not as simple as a linear distance from a gathering line. As EPA acknowledges in the preamble, there are many factors that determine gathering line availability – not just distance. There are other considerations that drive the decision to recover gas which include, but are not limited to, the following factors: gas volume, gas pressure, gas Btu content, gas liquid content, sales line gas pressure requirements, moisture

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[46] Comments of the Independent Petroleum Association of America and Western Energy Alliance on White Papers on Methane and VOC Emissions in the Oil and Natural Gas Sector per the Climate Action Plan Strategy to Reduce Methane Emissions (June 16, 2014).

[47] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,630, 56,632 (Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60).

requirements, compression, and current takeaway capacity of existing gathering systems. One workable approach that might assist regulators is to use a linear distance, such as a ¼ mile, to presume that flaring is permitted because it is generally agreed that, beyond that distance a gathering line is not available. The converse, a gathering line within a ¼ mile, should not be assumed to be available prompting a case-by-case determination based on the factors detailed above. Again, IPAA/AXPC supports EPA's acknowledgment that the availability of a gathering line must be considered in evaluating the feasibility of an oil well completion but that it is not as simple as designating a linear cut point.

IPAA/AXPC supports the various exclusions from the oil well REC requirements for oil wells less than 15 boe; wells with a gas-to-oil ratio (GOR) of 300 or less; and the low-pressure well. Although not an exact science, operators can make engineering judgments and estimations based on experience in a developed formation. If the well initially exceeds 15 boe, a potential solution is to allow the operator to temporarily shut in the well and bring in REC equipment or limit the production such that the well does not make more than 15 boe for any measurement period as long as the average rate of the averaging period is 15 boe or less. In the event that the operator, based on strong well performance, decides to bring in REC equipment, he could earn a 0 bopd credit to the averaging period for every day the REC is used. IPAA supports the inclusion of an exclusion for a "low-pressure oil well" but it is not appropriate to utilize the definition for a "low-pressure gas well." Oil and water are fairly equivalent on their impact on the intent of this low-well pressure exemption in the early phases of flowback, and the water/oil ratio will change significantly during the early flowback periods for hydraulically fractured wells. The main difference is that, once the hydraulic fracture load stops coming back, a gas well will typically have much less liquids in the production tubing, making the surface pressure actually higher for the gas well vs. an oil well. This difference would be reflected in the 0.038 number which represents the gas gradient in the well, which would impart a back pressure. For oil wells this back pressure would be higher, i.e. more liquids in the tubing, and this factor should be increased. For example a well making 15 boe up 2-3/8" production tubing at a 300 GOR could have a gradient of 5 to 10 times as much. The new record-keeping requirements associated with oil RECs (but also applicable to natural gas RECs) disproportionately impact the smaller, independent operators (conventional operations).

Finally, IPAA/AXPC continues to believe EPA's cost-effectiveness analysis for oil well completions is flawed because it is taking "credit" for well completions industry has already done or will do regardless of regulations. IPAA and WEA filed extensive comments on EPA's oil well completion White Paper on June 16, 2014.[48] The issues raised in that process have not been adequately addressed by EPA in the RIA or Technical Support Document for this rulemaking. The most relevant provisions of those comments are reproduced below:

> Finally, we question the need or benefit of EPA requiring reduced RECs or combustions devices/flares at oil wells as operators are already engaged in such

[48] Comments of the Independent Petroleum Association of America and Western Energy Alliance on White Papers on Methane and VOC Emissions in the Oil and Natural Gas Sector per the Climate Action Plan Strategy to Reduce Methane Emissions (June 16, 2014). The Comments of AXPC/America's Natural Gas Alliance (ANGA) are incorporated by reference.

> practices at a majority of the wells. There is a clear economic incentive to capture as much of the gas as possible and where it is not possible to capture the gas, safety concerns for the personnel at the well site drive the installation of flares. It is a matter of economics and common sense—if the gas can be captured economically, it will be. If it cannot be captured economically, and it is present in sufficient quantities to represent a safety concern, it is flared.
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> See the comments above, as they pertain to EPA's data sources and estimates.
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> For the reasons set forth above, we have considerable doubt as to the accuracy of the national and per well estimates of methane and volatile organic compounds ("VOC") emissions for hydraulically fractured oil well completions. There is significant variation in the emissions among different well types and wells from different regions. As such, a "national estimate" will not necessarily be representative of wells from a particular region (and, in fact, would be representative only by chance).
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> . . .
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> As to factors that influence emissions, there are numerous factors that were not discussed in the White Papers. Most importantly, the White Papers do not adequately address the complex nature of what EPA terms "co-produced" wells, where both oil and gas are produced. Such wells are difficult to classify in terms of how any given well will behave in a wide variety of geologic formations and basins. In addition, EPA does not discuss the well-established fact that nearly all oil wells that produce appreciable amounts of gas are controlled by a combustion device for safety reasons. As mentioned above, the existing economic and safety incentives result in a majority of these wells being "controlled"—whether by a REC or combustion device. In fact, a survey submitted as part of the docket for NSPS Subpart OOOO was conducted by AXPC/ANGA member companies that showed that greater than 90% of wells were controlled prior to the rulemaking. Comment submitted by Amy Farrell, Vice President of Regulatory Affairs, America's Natural Gas Alliance (ANGA) and Bruce Thompson, President, American Exploration and Petroleum Council (AXPC); EPA-HQ-OAR-2010-0505-4241. A similar Texas Energy Alliance survey had comparable results, again supporting the position that further EPA requirements mandating REC/flares are not necessary.[49]

In the TSD for the proposed Subpart OOOOa, EPA continues to claim ignorance as to the extent state and local regulations require well completions and claim an arbitrarily low assumption that only 7 percent of completions are controlled in the absence of federal regulations.[50] This

[49] *Id.* [internal citations omitted]

[50] TSD at 22.

arbitrarily low assumption skews EPA's cost-effectiveness and takes "credit" for activities the industry is doing on its own.

D. Pneumatic Pumps

IPAA/AXPC's primary concern with the proposed requirements for pneumatic pumps is that EPA has overestimated the ease (and thus the cost) of sending captured gas to an existing combustion device. It is not as simple as plumbing a line from the pump to the control device. The intermittent nature of the gas flow and low pressures can create serious safety and operational difficulties if not appropriately designed along with significantly increasing engineering costs associated with the closed vent system upgrades. The difference between the amount of gas being vented from a storage tank and the amount of gas coming from a pneumatic pump is large, and designing a closed vent system to properly account for this pressure differential would be exceedingly difficult and costly. To meet the needs of both components, the final design would likely have the potential to increase emissions (such as being forced to use a small compressor or being forced to set thief hatches at different pressures that in turn cause more emission events from the tanks) than if the pump was vented directly to the atmosphere. The volume of gas to be captured from pneumatic pumps is relatively small, and when EPA more accurately reflects the cost associated with capturing the gas and routing it to an existing control device, IPAA/AXPC questions whether the proposed controls will be cost-effective. If EPA persists with its proposed controls on pneumatic pumps, it should clarify the definition of an "affected facility" and the interplay with reporting requirements. "Affected facility" should mean only new or modified continuous high-bleed pumps and specifically exclude low-bleed pumps (< 6 scfh). Since low-bleed pumps would not be considered an "affected facility," it is assumed they would not be subject to the reporting requirements for high-bleed pneumatic pumps. IPAA/AXPC requests confirmation of its reading of the reporting requirements.

The applicability of EPA's proposed regulations turns on whether a control device is already present at the site. EPA's regulations and preamble are silent as to whether the existing control device is already subject to NSPS and therefore an affected facility. To the extent the existing combustion device is not an affected facility, Subpart OOOOa should be clarified that existing, non-affected facility combustion devices should not become subject to NSPS simply because a new pneumatic pump is installed or an existing pump is modified. If EPA intends to pull in the existing control device and make it an affected facility, EPA must revise its cost-effective analysis to account for the additional costs associated with "converting" the existing control device to an affected facility.

E. Compressors

IPAA/AXPC supports EPA's indication that the compressor rules promulgated under Subpart OOOO and proposed Subpart OOOOa do not apply to compressors at the wellsite. IPAA/AXPC interprets the proposed CTG for compressors as essentially the same as that proposed in Subpart OOOOa, yet the CTG indicate the regulations would apply to compressors "between the wellhead and point of custody transfer."[51] This language seems inconsistent with the concept that compressors at the well site are not subject to Subpart OOOO or the proposed Subpart OOOOa. IPAA/AXPC requests clarification. Similarly, IPAA/AXPC requests clarification on whether compressors at well sites are subject to LDAR requirements. Finally, in response to EPA's specific request, IPAA/AXPC suggests the fugitive emissions requirements at compressor stations should apply only to the fugitive sources that are connected to the added or modified compressor.

F. Liquids Unloading

IPAA/AXPC supports EPA's conclusion that it does not have sufficient information to propose standards for liquids unloading. IPAA and WEA filed extensive comments on EPA's liquids unloading White Paper on June 16, 2014.[52] The numerous issues raised by IPAA/WEA have not been adequately addressed and continue to be the basis for IPAA/AXPC's position that controls aimed at reducing emissions from liquids unloading vary greatly based on numerous factors that make it difficult if not impossible to promulgate a cost-effective NSPS. IPAA/AXPC incorporates by reference these comments in their entirety regardless of topic. Nonetheless, certain portions of IPAA/WEA's comments on liquids unloading warrant repeating:

> The industry has a strong economic incentive to minimize venting episodes. Indeed, what EPA views as a pollutant is generally viewed by industry as a salable product and thus industry has an economic incentive to capture as much of the gas as possible. Unfortunately, it is not always possible to unload without venting—sometimes for safety reasons and sometimes for technological reasons. The limitations on the ability to minimize venting are difficult to predict and largely well-specific.
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> Although the challenges associated with liquids unloading are equally prevalent among horizontal and vertical wells, the ability to recover the cost of "controls" will most likely disproportionately affect smaller operators, marginal wells and vertical wells. Nowhere in the charge questions or White Paper does EPA attempt to address the potential for such disproportionate economic impacts to result from a "one size fits all" approach to minimizing emissions during liquids unloading. The need to unload liquids depends primarily on reservoir pressure, liquid/gas ratio, and surface operating pressure; the most appropriate technology used to unload will depend on the producing formation, site equipment and logistics, and other considerations. There is a wide variety of reservoir properties across and within basins, and flexibility is critical in the continued production of these wells.

[51] U.S. Environmental Protection Agency, Control Techniques Guidelines for the Oil and Natural Gas Industry (Draft), (Aug. 2015) *available at* http://www3.epa.gov/airquality/oilandgas/pdfs/og_ctg_draft_081815.pdf.

[52] Comments of the Independent Petroleum Association of America and Western Energy Alliance on White Papers on Methane and VOC Emissions in the Oil and Natural Gas Sector per the Climate Action Plan Strategy to Reduce Methane Emissions (June 16, 2014).

As a general matter, the national estimates of methane emissions based on EPA's Greenhouse Gas Reporting are overstated, over-reported and dated at this point. The 2012 API/ANGA study included in the White Paper indicates as much and concludes that EPA's Greenhouse Gas Inventory was overestimated by orders of magnitude. More source specific data—i.e., data specifically focused on liquids unloading—is needed before conclusions should be drawn as to this subsector's contribution to methane emissions from the broader oil and natural gas sector.

The formulas used by EPA to calculate the gas volumes vented during unloading events estimates that the entire well column is vented during an event. The reason for the unload is because fluid is sitting in this column, taking up this space, and resulting in an overestimation of emissions. Additionally, the formulas utilize only a casing diameter for wells without plunger lifts (and tubing diameter for wells with a lift). Most wells are generally equipped with production tubing strings in an effort to increase the velocity of the gas and liquids and reduce the potential for liquid [un]loading problems. When these tubing strings are in place, gas volumes vented during unloading events would be from the casing-tubing annulus (area between the outside of the tubing and the inside of the well's casing) and not from the entire volume of the well's casing. This is not accounted for in many of the estimates.

In addition, the formulas used by EPA assume that gas is being vented for any well liquid unload lasting longer than one hour (or 30 minutes for unloads that are plunger lift assisted). During the liquid unloading process, there is usually an initial release of gas followed by a period of time where operators are waiting for the liquid to travel up the well bore and nothing is being released from the well; this can happen for only a few minutes or up to several hours. The formulas assume that any duration longer than one hour is continually venting at a rate equal to the production rate of gas when in fact no gas is being vented, significantly overestimating the emissions from these activities.

Factors influencing regional differences in VOC and methane emissions are a complex set of variables that include temperature, pressure, hydrocarbon composition of the oil and gas within the production formation, gas to liquid ratio, well configuration, well depth and surface conditions at the time of the unloading event. The factors that influence the frequency and duration of liquids unloading include those listed in the previous sentence, and the solution for each well and/or application is based on engineering calculations and judgment and is intrinsically well-specific. Production engineers run models to determine the proper design and operating parameters. The numerous factors and inability to generalize even by formation make it difficult to predict which wells will be more susceptible to high levels of emissions associated with liquids unloading.

The need for liquids unloading is not based on a strict set of parameters or rules. It is based on a complex set of variables—primarily reservoir pressure, but also including (but not limited to) gas to oil ratio, geologic formation types, and age of well. In addition to geological factors, technology-based factors include (a) large or no production tubing strings installed, (b) wells with high sales line pressure and no compression equipment installed at the surface, and (c) wells not equipped with artificial lift equipment such as gas lift mandrels/valves, plunger lift, rod pump, etc. Regarding the type of well, horizontal or hydraulically fractured wells are no more likely than vertical or non-hydraulically fractured wells to develop liquids [un]loading problems. It is not only a problem for wells further down their decline curve.

Simply put, one cannot generalize—there is no particular pattern or predictable model that would forecast which well types are prone to having liquids [un]loading problems. It is the inability to generalize that makes each well unique and requires a case-by-case analysis to address a liquid [un]loading problem. That said, there are some trends—the highest tendency are deeper wells with high liquid to gas ratios and low bottom hole pressure. Because the reservoir pressure does decline over time, liquid [un]loadings are more prevalent in older wells. Wells drilled and completed in formations drained by previous production may experience [un]loading problems more quickly. All wells with liquid saturations above irreducible levels will develop liquid [un]loading conditions.

The cost of the technologies varies and what will constitute a cost-effective technology will vary from well to well. For example with plunger lifts, the capital, installation, and startup cost is an exponential costing issue based on ever increasing depth of the well (e.g., the cost of a 11,000 to 12,000 foot well might approximate $25,000 to $30,000 for certain operations in East Texas whereas a 1000 foot well may only be $2000 or $3000). Also related to plunger lifts, a "smart technology" cost is dependent on many variables such as well density and availability of a communication network. The communication network for 400 densely spaced wells can easily cost approximately $4 million dollars (average of $10,000/well before adding the cost of the smart controls themselves). The EPA's high range of $18,000/well is not necessarily "high" for many situations. As to artificial lifts, the costs are substantially more. One member indicated capital and installation costs for 11,000 -12,000 foot wells are in the range of $150,000 per well -- much higher than EPA's estimates. Again, the depth of the well influences the costs figures and it is difficult and inappropriate to generalize. The best solution to the liquids unloading problem is a case-by-case decision based on the engineering judgment of the operators.

. . .

As noted above, the feasibility of the use of artificial lift systems is generally site-specific and therefore it is difficult to generalize. Artificial lift systems are just one of the available "tools" or technologies to extend the useful life of a well and are utilized where cost-effective. That said, they tend to be cost-prohibitive on deeper low production gas wells and work best on shallow wells

> capable of setting a pump/plunger/gas lift below the bottom perforations. Some characteristics that discourage the use of artificial lift include deep formations, corrosive production fluids, wells with high scaling tendency, and deviated wellbores. The feasibility of artificial lifts must be assessed according to the conditions of the individual well. One size does not fit all.
>
> In certain situations, gas wells with liquid content that are unloaded are capable of being controlled with flares attached to the tank vents at the production battery. In others, the high pressures in certain regions make routing blowdowns to tanks and flares extremely unsafe. Even wells that are blown down can sometimes be vented through tanks that are controlled in many cases by flares. The capability to do this, however, depends greatly on the conditions of the well bore and the equipment used to control (tanks, flares, etc.) These flares and the associated tanks/tank vents are not specifically designed to accommodate liquids unloading. Regarding the use of flares specifically for liquids unloading events, there are several design and operational issues: (1) liquids unloading are slug flow events that are inconsistent in both gas volumes and quality, (2) consequently, designing a flare for the wide range of operating conditions is challenging, (3) additional equipment may be required to prevent liquids from reaching the flare (separators, etc.), and (4) the intermittent nature of these events is another challenging design condition especially in avoiding smoking conditions, etc. To the extent that EPA contemplates a continuous flare to minimize emissions from these intermittent events, the negative externalities associated with the carbon dioxide emissions from the pilot should be factored into any analysis. To accommodate the operational issues associated with flares and associated equipment designed to specifically address liquids unloading, they would need to be relatively large which could present safety hazards and create local permitting issues.[53]

EPA's proposed Subpart OOOOa seems to leave the door open for potential regulation of emissions associated with liquids unloading and requested comment on the issue. IPAA/AXPC supports EPA's decision to not propose federal standards. The issues outlined above have not been adequately addressed by EPA and remain largely unaddressed.

G. <u>Miscellaneous Requests for Input</u>

- EPA requested input on "pressure-assisted flares." IPAA/AXPC is not entirely clear what EPA is referring to as pressure-assisted flares. To the extent IPAA/AXPC understands the type of flare EPA is referring to, IPAA/AXPC does not believe there is any reason to treat these flares differently than any other flare. Or stated slightly differently, pressure-assisted flares should be treated as any other flare subject to the Subpart OOOO and proposed Subpart OOOOa regulations

[53] *Id.*

- IPAA/AXPC supports a clarification that the storage vessel provisions do not apply to large (e.g., 25,000 bbls or more) tanks used for water recycling, as they have very low emissions but might trigger the 6-ton threshold because of size and volume of throughput. EPA's recognition that this water has very low emissions calls into question whether the smaller "storage vessels" that hold the same type of water, just smaller quantities, should be an affected facility.
- IPAA/AXPC does not support EPA's concepts of independent third-party verification, fugitive emissions verification, and "electronic reporting and transparency" as described as part of EPA's Next Generation Compliance and Rule Effectiveness. As an initial matter, companies should be allowed to verify issues internally. EPA's concept of utilizing certified reviewers would pose a significant problem for the industry in terms of not having enough qualified individuals to conduct the review. Eventually the market would adjust, but in the short term there would be a shortage. EPA's concept would create a problem in an attempt to solve an "issue" that currently does not exist. Finally, industry does not support a continuous parametric monitoring system since this would result in significant costs to companies that do not have supervisory control and data acquisition (SCADA) capabilities and would another add link in the system that could fail. A simpler and better solution would be to require all thief hatch vents to be set at a pressure above that of the main ventline.

V. Control Technique Guidelines for Ozone Nonattainment Areas

Clearly, the CAA provides direction to EPA and states that requires the use of RACM in Ozone nonattainment areas to manage emissions from existing sources. However, EPA's presentation of the CTG for oil and natural gas production facilities fails to provide a technological analysis based on the fundamental basis for RACM. Instead, it arbitrarily applies the new source BSER requirements to existing sources without any realistic analysis of whether these technologies are reasonably available and applicable as RACM. Moreover, as IPAA/AXPC demonstrated earlier in these comments, the differences between the oil and natural gas production industry and other industry segments requires a recognition that there are significant differences across the industry in the size and scope of operations that dramatically impact the economic implications of controls. The CTG proposals largely ignore this reality. Any CTG for oil and natural gas production facilities needs to provide an application threshold that excludes marginal oil and natural gas wells. Finally, with the revision to the NAAQS for Ozone, new areas – many of which are rural in nature – will be subjected to the RACM created by the proposed CTG. Without the appropriate recognition of the broad diversity of the oil and natural gas production industry and the need for the CTG to be based on appropriate existing source technologies, serious adverse impacts on American production could result. Not only has EPA failed to address this issue in the CTG proposal, EPA's own assessment of the nation's ability to attain the Ozone NAAQS demonstrates that this CTG is both unnecessary and counterproductive.

Consequently, IPAA/AXPC requests withdrawal of the current CTG proposal until EPA can address its serious shortcomings and determine whether a broad CTG proposal is appropriate as a RACM approach for oil and natural gas production facilities.

Following is a detailed discussion of the basis for IPAA/AXPC's opposition to the current CTG proposal and reasons why it should be withdrawn.

In its Federal Register notice regarding the *Release of Draft Control Technique Guidelines for the Oil and Natural Gas Industry*, EPA provides a pertinent description of the RACM process:

> Section 172(c)(1) of the Clean Air Act (CAA) provides that State Implementation Plans (SIPs) for nonattainment areas must include ''reasonably available control measures'', including ''reasonably available control technology'' (RACT), for existing sources of emissions. Section 182(b)(2)(A)of the CAA requires that for Moderate Ozone nonattainment areas, states must revise their SIPs to include RACT for each category of VOC sources covered by a CTG document issued between November 15, 1990, and the date of attainment. CAA section 182(c) through (e) applies this requirement to States with ozone nonattainment areas classified as Serious, Severe and Extreme.
>
> The CAA also imposes the same requirement on States in ozone transport regions (OTR). Specifically, CAA Section 184(b) provides that states in the Ozone Transport Region (OTR) must revise their SIPs to implement RACT with respect to all sources of VOCs in the state covered by a CTG issued before or after November 15, 1990. CAA section 184(a) establishes a single OTR comprised of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont and the Consolidated Metropolitan Statistical Area (CMSA) that includes the District of Columbia.
>
> The EPA defines RACT as ''the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility'' (44 FR 53761, September 17, 1979).[54]

While this description is accurate, EPA wholly fails to meet the test of identifying "control technology that is reasonably available considering technological and economic feasibility."[55]

To understand EPA's failure, it is essential to expand our earlier discussion of the nature of the oil and natural gas production industry. As described earlier, the oil and natural gas production industry differs from other industries because of the inherent reality that its production is not constant. Instead, because of geological realities, production from most oil and

[54] Release of Draft Control Techniques Guidelines for the Oil and Natural Gas Industry, 80 Fed. Reg. 56,577, 56,578 (Sept. 18, 2015).

[55] *Id.*

natural gas wells peaks at or near its earliest stages of full production. In essence, once the reservoir is opened, the contained pressure in the reservoir forces oil and natural gas through the well bore to the surface. But, this pressure also begins to diminish and with it the flow rate of the well. While various techniques are available depending on the type of formation to improve production, these actions adjust the rate of decline; they do not return the well to its original productivity.

Consequently, over time, wells move from strong producers to marginal ones. In fact, marginal wells are defined in federal law as oil wells producing 15 barrels/day or less and natural gas wells producing 90 mcfd or less. While these are the thresholds, the average marginal wells produce at much lower levels – the average marginal oil well produces 2.7 barrels/day and the average marginal natural gas well produces 22 mcfd. There are business implications to this production depletion as well. As the operating costs of production increase when production decreases, companies sell less productive wells to obtain capital for reinvestment in new production. Many characterize the oil and natural gas production industry as a "food chain" industry with larger companies selling properties that do not fit their production structure to smaller companies. As a result, marginal well ownership is dominated by smaller organizations, many of which are privately held small businesses. As IPAA/AXPC previously stated, there are over 1.1 million oil and natural gas wells in the United States; approximately 760,000 are marginal wells.

Correspondingly, as production from wells decreases, the physics of emissions changes as well. With less pressure in the well bore, there is less pressure driving emissions to the atmosphere from operating equipment. Even more telling, the most recent research efforts such as those by the University of Texas' Center for Energy and Environmental Resources demonstrate that emissions at oil and natural gas production operations are dominated by a small percentage of sources. Moreover, experience is indicating that when these sources are corrected and maintained, emissions reductions are sustained for long time periods.

Set against this pattern of industry structure and experience, EPA has failed to create a record that demonstrates it made a thoughtful analysis of the technologies it is proposing in the CTG as RACT – particularly in the context of considering technological and economic feasibility. Instead, EPA has arbitrarily applied the BSER technologies in Subpart OOOO and proposed to do so in Subpart OOOOa as they relate to new sources in the context of existing sources. In doing so, EPA fails to appropriately adjust the economic analysis from the NSPS materials to reflect the different circumstance of existing operations.

Among the key factors that EPA understates is the need to focus these regulations on VOC emissions. Because these CTG address VOC emissions, their cost effectiveness and technological appropriateness must be evaluated with regard to their impact on VOC emissions. For example, EPA bases much of its cost-effectiveness determinations on average VOC emissions, but RACT needs to be considered by each state for each nonattainment area. Different oil and natural gas formations produce different vapor compositions including significantly different fractions of VOCs in the vapor. Correspondingly, for the same cost, cost effectiveness will change; it will become less cost-effective as the VOC concentration diminishes.

Similarly, EPA bases much of its analysis on "model" facilities, but facilities differ depending on the nature of their operations. While EPA's draft CTG proposal recommends that facilities with only a wellhead should not be included in its fugitive emissions CTG, it should similarly recognize that facilities with fewer components than the EPA model facility need to be evaluated based on their actual structure rather than presumed to be cost-effectively controlled under the CTG.

These issues become more compelling when the CTG affect marginal oil and natural gas wells. EPA partly recognizes this reality by stating in the context of its fugitive emissions proposed CTG:

> For purposes of this guideline, the emissions and programs to control emissions discussed herein would apply to the collection of fugitive emissions components at a well site with an average production of greater than 15 barrel equivalents per well per day (15 barrel equivalents), and the collection of fugitive emissions components at compressor stations in the production segment. It is our understanding that fugitive emissions at a well site with low production wells are inherently low and that many well sites are owned and operated by small businesses. We are concerned about the burden of the fugitive emissions recommendation on small businesses, in particular where there is little emission reduction to be achieved.[56]

This recognition is entirely appropriate and accurate. However, it needs to apply to all of the CTG. Marginal wells are the most vulnerable U.S. production operations – particularly at the current oil and natural gas commodity prices that are well below the prices used by EPA in its cost-effectiveness analyses. Yet, these wells continue to provide a significant portion of American production. Additionally, the CTG should provide that status as a marginal well qualifies for an off ramp from continuing application of the regulations. That is, when a well's production drops to the point where it is considered a marginal well, the facility would no longer be subject to the regulation.

EPA also needs to recognize that its CTG proposal coincides with its decision to lower the Ozone NAAQS. American oil and natural gas operations are located where the resources exist. Unlike manufacturing facilities, they cannot choose where to operate. Historically, much of America's oil and natural gas has been located in largely rural areas. Recent development of American shale resources has placed operations closer to populated areas – many of which are in Ozone nonattainment areas. However, EPA's decision to lower the Ozone NAAQS captures areas that have previously been in attainment. Since a number of these new projected nonattainment areas encompass production areas, these CTG will have a broader and more significant potential impact on U.S. production. The following map provides a perspective on the interaction between American production areas and nonattainment with the new Ozone NAAQS.

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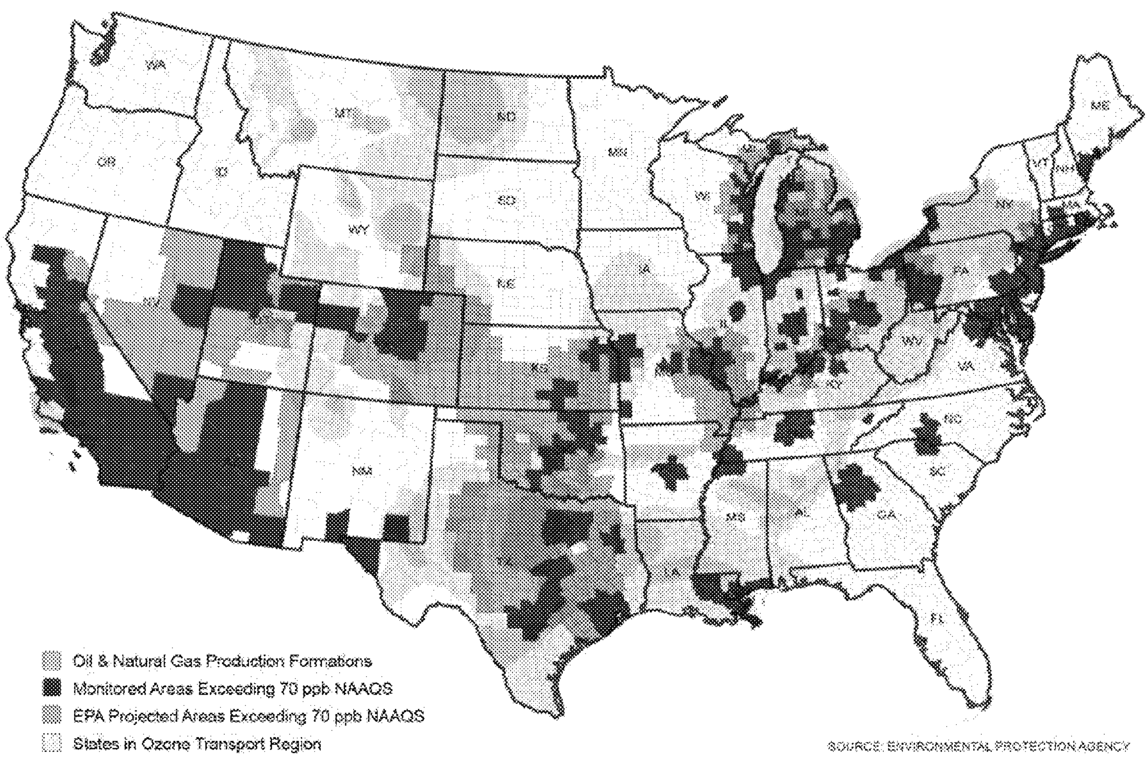
[56] U.S. Environmental Protection Agency, Control Techniques Guidelines for the Oin and Natural Gas Industry (Draft), (Aug. 2015) *available at* http://www3.epa.gov/airquality/oilandgas/pdfs/og_ctg_draft_081815.pdf.

Ozone Nonattainment Areas Impacting American Oil & Natural Gas Production



While oil and natural gas production facilities have always been subject to RACM in current Ozone nonattainment areas, the CTG proposal changes the regulatory framework significantly. Part D of the CAA provides for states to impose RACM on existing stationary sources as a part of the requirements to demonstrate attainment or Reasonable Further Progress toward attainment. These RACM requirements, however, apply to stationary sources of a specific size depending on whether an Ozone nonattainment area is classified as Moderate, Serious, Severe or Extreme. Therefore, regulation of existing oil and natural gas production facilities depended both on their size and the status of the Ozone nonattainment area. The CTG proposal in general does not set emissions thresholds for its application. As such, for large or small producers, or large or small emitters, the regulatory burden will apply and will apply far more broadly.

As EPA states with regard to the proposed Subpart OOOOa, "we [EPA] believe that the industry can bear . . . and survive."[57] However, no broad analysis of the collective impact of the CTG proposal on American oil and natural gas production in the context of the revised Ozone NAAQS has been done. Such an analysis should be done for several pertinent reasons.

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[57] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,629 (Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60).

1. Ozone has consistently been the most difficult primary NAAQS for certain areas to meet. The following figures demonstrate the reality of Ozone NAAQS nonattainment. Figure 1 presents EPA's assessment of the areas of the country that fail to meet the 1997 Ozone NAAQS of 84 ppb (8 hour). Figure 2 presents EPA's assessment of the areas of the country that will fail to meet the current Ozone NAAQS of 75 ppb (8 hour) in 2020. Figure 3 presents EPA's assessment of its revised Ozone NAAQS by 2025.

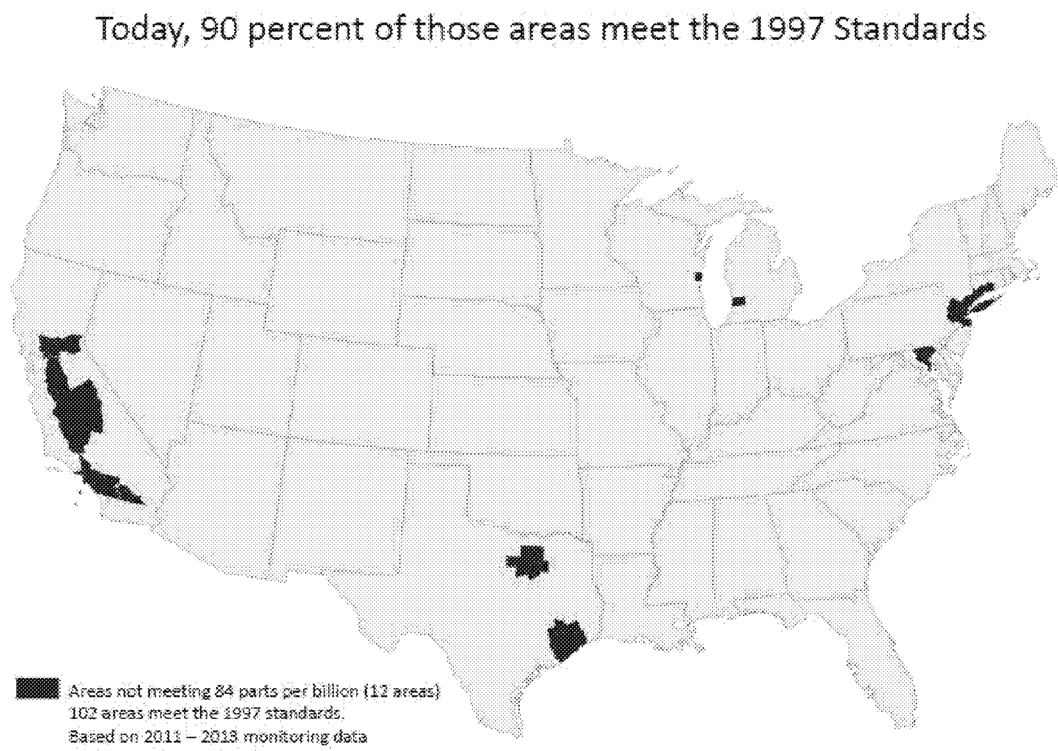


Figure 1

Source: Environmental Protection Agency

Counties with Monitors Projected to Violate the 2008 8-Hour Ozone Standard of 0.075 parts per million (ppm) in 2020

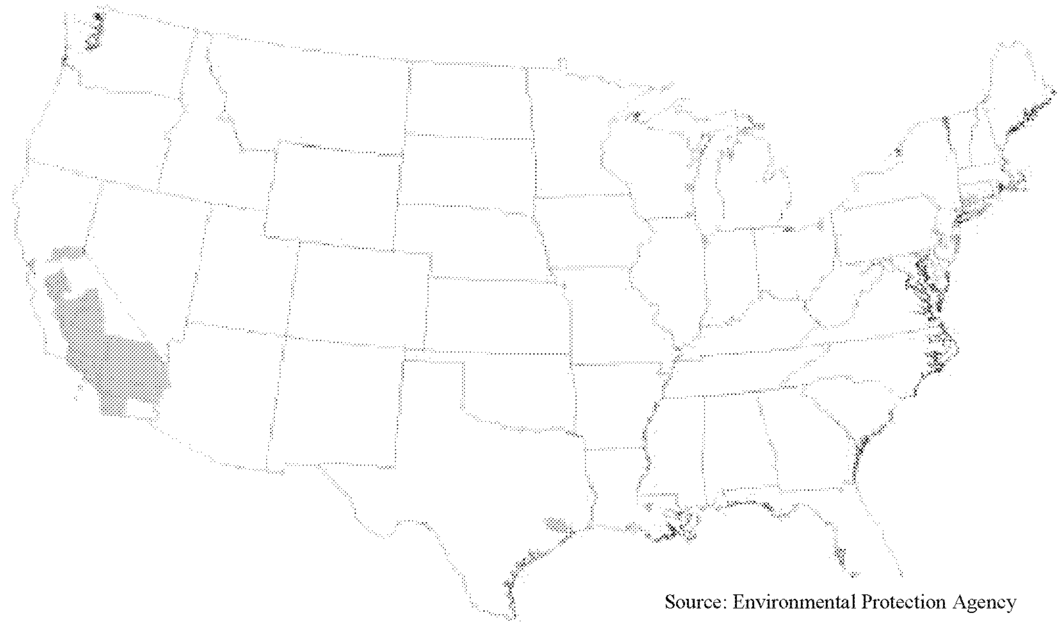


Figure 2

Source: Environmental Protection Agency

Figure 3

Source: Environmental Protection Agency

EPA's analysis shows that there are certain areas of the country that are enduring Ozone NAAQS nonattainment areas – areas that cannot meet any Ozone NAAQS that has been promulgated. The same areas that failed to meet the 1997 Ozone NAAQS and the 2008 Ozone NAAQS also will fail to meet the proposed NAAQS by 2025 and, realistically, any time until well after 2030. What this means is that EPA's claimed health benefits from the proposed NAAQS will not occur in these enduring nonattainment areas.

Equally important, the regulatory requirements in these enduring nonattainment areas will be no different under the proposed NAAQS than they are under the current NAAQS. These areas are subject to regulation under Part D – Plan Requirements for Nonattainment Areas of the CAA.

Part D was created in the 1990 CAA amendments. It creates a series of specific minimum requirements for each area in Ozone NAAQS nonattainment initially based on the area's ozone monitoring values relative to the Ozone NAAQS. Areas are classified as Marginal, Moderate, Serious, Severe and Extreme. Each classification is given a specific time frame in which to attain the Ozone NAAQS. Importantly, if an area fails to meet the NAAQS in its allotted compliance period, it is reclassified to a higher classification, required to implement the mandatory requirements and given an extension of time to meet the NAAQS. Part D requirements were initiated after the 1990 CAA amendments with attainment dates ranging from 1993 to 2010. Even with attainment date extensions, these dates have passed.

The significant impact of Part D is that perpetual nonattainment eventually produces a baseline of regulations and requirements of additional annual percentage reductions. Since these areas have been subject to Part D for 25 years, their future regulatory requirements will be the same iterative percentage reductions under the current NAAQS as the new one. Adopting the revised NAAQS will produce the same regulatory requirements for these areas as the current NAAQS.

2. EPA has stated in its support documents for its revised Ozone NAAQS that:

> Existing and proposed federal rules . . . will help states meet the proposed standards by making significant strides toward reducing ozone-forming pollution. EPA projections show the vast majority of U.S. counties with monitors would meet the proposed standards by 2025 just with the rules and programs now in place or under way.

Consequently, these national, federal requirements will essentially protect the overwhelming number of areas that would be placed in Ozone NAAQS nonattainment by the lower NAAQS without any of the local actions that would be required from such categorization.

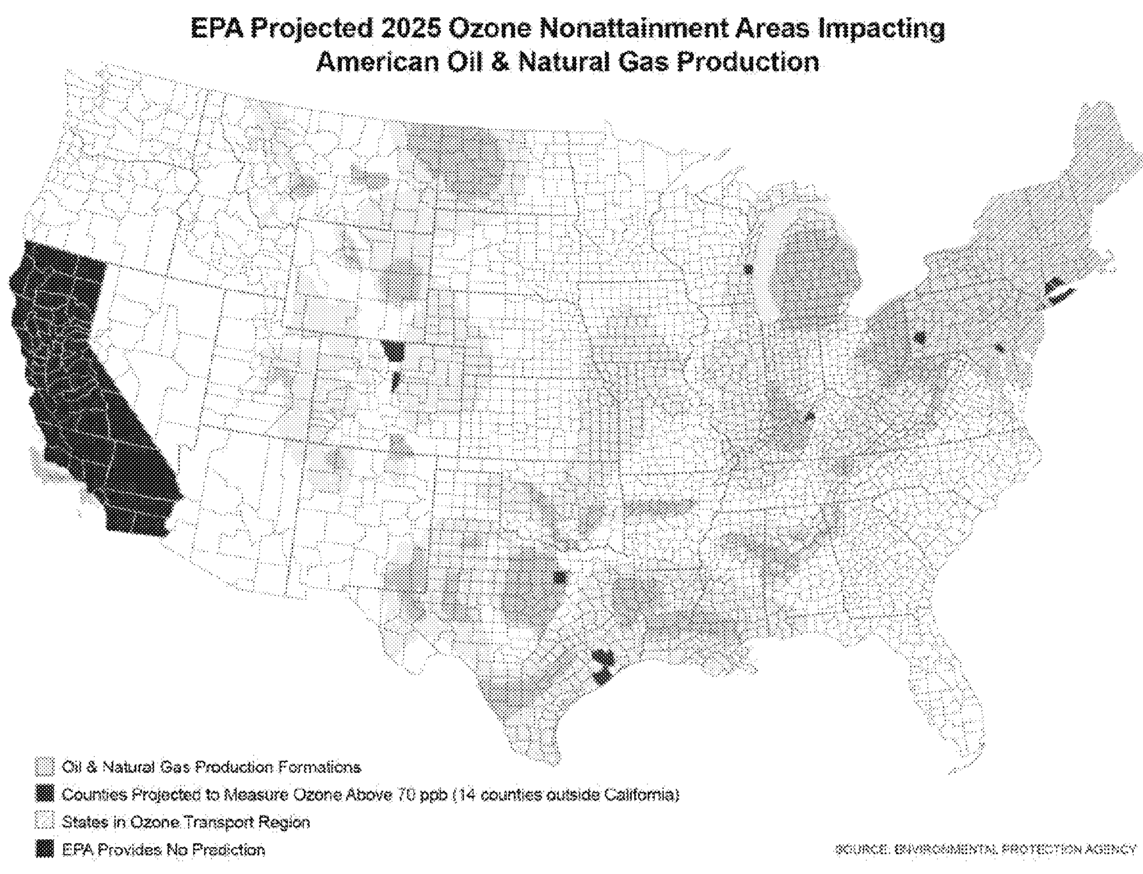
For these areas that EPA projects would reach attainment using only national, federal mandates regardless of the NAAQS, promulgating the lower NAAQS will compel them to be subject to the requirements of Part D of the CAA. Because Part D imposes a series of minimum requirements, the revised NAAQS will impose emission controls on new sources in those areas, including offsets, which will be burdensome, cost ineffective and unnecessary since EPA believes these areas would reach attainment using only its national regulations.

Once an area becomes subject to Part D, minimum requirements are mandated. For example, all new construction must not only comply with rigorous emissions controls, but all remaining emissions must be "offset" by reductions in existing emissions that are not otherwise regulated. Many of the areas that would fall into initial Ozone NAAQS nonattainment but would later attain the NAAQS are largely rural or with smaller municipalities. These areas will likely have limited existing emissions sources to regulate. These areas will face either an effective construction prohibition or the choice of shutting down existing operations that employ current workers.

3. The proposed oil and natural gas production CTG get pulled into this murky process. Enduring Ozone nonattainment areas already are a possible target for RACM requirements, but those requirements are predicated on the size of the source and

therefore not imposed without consideration of their impact on emissions and with localized consideration of cost effectiveness. For the newly captured Ozone nonattainment areas that EPA believes will meet the revised Ozone NAAQS using national, federal regulations – an assessment made without the inclusion of the proposed CTG – the application of the proposed CTG is unnecessary to reach attainment. However, because the CTG would be applied and would be applied to such small sources, these reductions are also removed from the possible pool of emissions that could be managed as a part of emissions offsets needed to build new facilities. In many of these areas, new facilities are likely new oil and natural gas wells. Consequently, the impact of the CTG would be to limit new production.

For these reasons, EPA must fully assess the energy, economic and environmental consequences of implementing the proposed CTG in the context of the revised Ozone NAAQS. IPAA/AXPC believes that EPA cannot justify the current CTG at this time. As the following graphic shows, EPA projects that only a few areas will remain in Ozone nonattainment in 2025.



This projection is based on regulatory actions taken without the proposed CTG. It demonstrates that the CTG is not essential to Ozone NAAQS attainment. Certainly, in some enduring nonattainment areas some oil and natural gas production facilities would be subject to RACM, but these decisions would be based on local conditions and the economic circumstances of the oil and natural gas production operations in those areas. Finalizing the proposed CTG would make all oil and natural gas production operations subject to the CTG without a compelling need – based on EPA's own projections of Ozone attainment – and without the opportunity to assess local need. Moreover, it would eliminate possible actions that could facilitate new construction as offsets and thereby unnecessarily threaten economic growth in these areas. If EPA finalizes an oil and natural gas production CTG without assessing all of these consequences, it can only be viewed as arbitrarily ignoring significant implications that EPA has the responsibility to address.

It is pertinent to address the methane emissions issue here, too. While this proposed oil and natural gas production CTG is written to manage VOC emissions, it has been proposed as a part of the Administration's Climate Action Plan and is partly a surrogate for methane emissions management. However, as IPAA/AXPC stated earlier in these comments, the requirements already in regulation under Subpart OOOO more than achieve the Administration's methane reduction targets for the oil and natural gas production segment of the Climate Action Plan. This CTG needs to be addressed on its merits and its consequences weighed with regard to Ozone NAAQS nonattainment.

In addition to these general concerns, IPAA/AXPC has issues associated with the specific CTG proposals.

A. Fugitive Emissions

IPAA/AXPC identified a series of specific issues in the discussion of the Subpart OOOOa proposal that apply in the CTG context as well. Here, this discussion will focus on some of those issues and raise others that arise because of its application to existing sources.

First, EPA's approach to a fugitive emissions program fails to recognize the nature of these emissions at oil and natural gas production facilities. This emissions arena is characterized by "fat tail" emissions where a few components within the facility account for the overwhelming amount of the releases. At the same time, it is an arena where the appropriate regulatory formulation is still being identified. Several states have initiated fugitive emissions programs, and each differs from the others. Clearly, it will take some time to determine the efficacy of approaches in order to assure that a cost-effective program is defined. Into the middle of this uncertainty, EPA proposes the most burdensome approach with expectations of success that are not founded on experience. Rather than bullying its way into the arena, EPA has two far better approaches it could take. One is to watch the emerging state programs and use their results to design a program. The second is to work with industry to develop voluntary initiatives that would reflect the emerging understanding of fugitive emissions patterns. IPAA/AXPC believes that EPA should withdraw its fugitive emissions proposals until more is known about the best approaches to managing them.

Second, initial experiences with state programs are revealing that once a "fat tail" source is corrected through appropriate maintenance, its emissions do not increase – at least for long periods of time. In fact, because the current state programs have been operating for a limited amount of time, some sources that have been fixed have not needed a second action. However, like its NSPS proposal, EPA creates a framework of shifting monitoring frequencies that are not justified based on experience. If EPA continues to pursue its proposal, it should rely on an annual inspection cycle to create a stable planning framework.

Third, when states have or create their own fugitive emissions programs, these programs should be considered as meeting CTG requirements.

Fourth, IPAA/AXPC supports excluding smaller facilities (e.g., marginal wells producing 15 barrels/day of oil equivalent or less) from the scope of the fugitive emissions program and believes that facilities that are initially included in any program should be excluded when their production falls below the threshold. IPAA/AXPC agrees that a fugitive emissions program should not apply to facilities with only a single wellhead. Further, EPA bases its program on a "model" facility with an expected number of components. IPAA/AXPC recommends that sites with less than the model facility components should be excluded from the fugitive emissions program.

Fifth, IPAA/AXPC believes that EPA is understating the costs of its fugitive emissions program and overstating its benefits. As IPAA/AXPC stated in discussing the NSPS proposal, EPA relies on technologies that are costly while not demonstrating those technologies are necessary to achieve benefits. For example, EPA is enamored with the use of specific OGI technologies. EPA places far too much faith that OGI can detect emissions accurately. Moreover, by using this technology, it drives compliance costs excessively. As described earlier, compelling the expenditure of more than $100,000 per FLIR camera is a burden not easily borne by existing operations where production rates are lower than new facilities in today's economic climate. EPA's proposal immediately demands confidence that the expenditure will result in substantial savings. However, nothing in EPA's CTG proposal demonstrates that it has realistically evaluated the effectiveness of this program at existing facilities. Past CTG have provided a threshold cost effectiveness test that is absent here. Rather, EPA calculates costs/ton of reduced emissions for various technologies whether they are appropriate as RACT. For example, EPA rather cavalierly discounts the costs/ton for oil wells – which exceeds $10,000/ton in all of its cases and reaches more than $25,000/ton in some – by stating "[t]he cost of control for natural gas well sites and gathering and boosting stations is considered to be reasonable."[58] Implicitly, the cost of control for oil well sites is not reasonable, but EPA proposes the same RACT requirements. IPAA/AXPC believes that oil well sites should be excluded from the CTG and that any natural gas well site program needs to be reconstructed to focus on high-emitting sources with flexibility to use more cost-effective approaches.

EPA errs in locking in current technologies, like OGI, that may well be far less cost-effective than new approaches that may arise as state programs learn from experience. As with the NSPS proposal, EPA needs to allow the development of knowledge in managing these fugitive emissions before framing a rigid and ineffective mandate.

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[58] U.S. Environmental Protection Agency, Control Techniques Guidelines for the Oin and Natural Gas Industry (Draft), (Aug. 2015) *available at* http://www3.epa.gov/airquality/oilandgas/pdfs/og_ctg_draft_081815.pdf.

B. Storage Vessels

There is a vast difference between regulating new storage vessels and existing ones. Specifically, a new vessel can be designed to accommodate a vapor collection system whether it is for recovery or combustion. Once built, both the vessel and the system can be maintained to assure that they are operating effectively and safely. Because a CTG addresses existing facilities, there is no certainty that the storage vessels will be capable of accepting the equipment needed to capture vapors. Vessels deteriorate over time despite maintenance, and if the structural integrity is compromised by the additional equipment, a safety issue arises.

In this context, and more generally, EPA's cost estimates must be scrutinized. EPA suggests that vapor recovery units (VRU) or combustors can be considered RACT for vessels with emissions of 6 tons/year or more. However, if a storage vessel cannot safely operate with additional equipment, the entire vessel would have to be replaced, if replacement is even economically feasible. EPA does not consider this situation in calculating its cost effectiveness, but it should because the consequences would considerably change the determination of RACT. For example, at some facilities under current economic conditions, the cost of a new storage vessel would not be economically feasible based on the facility's production rates.

Additionally, IPAA/AXPC believes that marginal well facilities should be excluded from the scope of the CTG. Clearly, the burden of adding capture equipment – and certainly the burden of replacing storage vessels – cannot be readily borne by marginal well operations. EPA relates emissions to production rates as shown in the following table. The information contained in the table shows that marginal well operations fall well below even EPA's presumed RACT threshold of 6 tons/year. Consequently, rather than deliberate on emissions estimates, the straightforward approach to defining the scope of the storage vessel CTG would be to exclude marginal well operations. Similarly, when a facility's production levels fall to the point when it becomes a marginal well operation, it should no longer be required to operate any vapor capture system. Beyond that, there should be the opportunity – like there is in Subpart OOOO – to demonstrate that uncontrolled emissions levels are below 4 tons/year to obtain an exclusion from the storage vessel CTG.

Table 4-2. Average Oil and Condensate Production and Storage Vessel Emissions per Production Rate Bracket[13]

Production Rate Bracket (BOE/day)[a]	Oil Wells: Average Oil Production Rate per Oil Well (bbl/day)[b]	Oil Wells: Crude Oil Storage Vessel VOC Emissions (tpy)[c]	Gas Wells: Average Condensate Production Rate per Gas Well (bbl/day)[b]	Gas Wells: Condensate Storage Vessel VOC Emissions (tpy)[c]
0-1	0.385	0.083	0.0183	0.038
1-2	1.34	0.287	0.0802	0.168
2-4	2.66	0.570	0.152	0.318
4-6	4.45	0.953	0.274	0.573
6-8	6.22	1.33	0.394	0.825
8-10	8.08	1.73	0.499	1.04
10-12	9.83	2.11	0.655	1.37
12-15	12.1	2.59	0.733	1.53
15-20	15.4	3.31	1.00	2.10
20-25	19.9	4.27	1.59	3.32
25-30	24.3	5.22	1.84	3.85
30-40	30.5	6.54	2.55	5.33
40-50	39.2	8.41	3.63	7.59
50-100	61.6	13.2	5.60	11.7
100-200	120	25.6	12.1	25.4
200-400	238	51.0	23.8	49.8
400-800	456	97.7	44.1	92.3
800-1,600	914	196	67.9	142
1,600-3,200	1,692	363	148	311
3,200-6,400	3,353	719	234	490
6,400-12,800	6,825	1,464	891	1,864
> 12,800[d]	0	0	0	0

Minor discrepancies may be due to rounding.
[a] BOE=Barrels of Oil Equivalent
[b] Oil and condensate production rates published by EIA. "US Total Distribution of Wells by Production Rate Bracket." http://www.eia.doe.gov/pub/oil_gas/petrosystem/us_table.html.
[c] Oil storage vessel VOC emission factor = 0.214 tpy VOC/bbl/day. Condensate storage vessel VOC emission factor = 2.09 tpy/bbl/day.
[d] There were no new oil and gas well completions in 2009 for this rate category. Therefore, average production rates were set to zero.

C. Pneumatics

The proposed CTG addresses both pneumatic controllers (regulated for new sources under Subpart OOOO) and pneumatic pumps (proposed for new source regulation under Subpart OOOOa). IPAA/AXPC believes that these requirements should not apply to marginal well facilities. In addition, EPA needs to clarify that the CTG does not apply to pneumatics with continuous emissions less than 6 scf/h.

D. Compressors

The proposed CTG addresses a subset of compressors as follows:

(a) *Centrifugal compressors*. Each centrifugal compressor, which is a single centrifugal compressor using wet seals located between the wellhead and point of custody transfer to the natural gas transmission and storage segment. A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not a source subject to VOC requirements under this rule.

(b) *Reciprocating compressors*. Each reciprocating compressor located between the wellhead and point of custody transfer to the natural gas transmission and storage segment. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not a source subject to VOC requirements under this rule.[59]

However, it makes no distinction based on the size of the facility. IPAA/AXPC believes that the CTG should not apply to marginal well facilities and that its application should be terminated when a facility becomes a marginal well operation.

E. Conclusion

The proposed oil and natural gas production CTG should be withdrawn. It fails to provide a technological analysis based on the fundamental basis for RACM. Instead, it arbitrarily applies the new source BSER requirements to existing sources without any realistic analysis of whether these technologies are reasonably available and applicable as RACM. It largely ignores the differences between the oil and natural gas production industry and other industry segments that require recognition of the significant differences across the industry in the size and scope of operations. These differences dramatically impact the economic implications of controls. While a portion of the CTG proposal creates an application threshold that excludes marginal oil and natural gas wells, a similar provision should apply to all of its provisions but does not. Finally, with the revision to the NAAQS for Ozone, new areas – many of which are rural in nature – will be subjected to the RACM created by the proposed CTG. Not only has EPA failed to address this issue in the CTG proposal, EPA's own assessment of the nation's ability to attain the Ozone NAAQS demonstrates that this CTG is both unnecessary and counterproductive.

VI. Comments on Source Determination Proposal

The EPA is soliciting comments on a potential revision of the process for determining the nature of a source for certain emissions units in the oil and natural gas sector. Among these are facilities that produce oil and natural gas. The proposal addresses CAA new source permitting

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[59] U.S. Environmental Protection Agency, Control Techniques Guidelines for the Oin and Natural Gas Industry (Draft), (Aug. 2015) *available at* http://www3.epa.gov/airquality/oilandgas/pdfs/og_ctg_draft_081815.pdf.

under the Prevention of Significant Deterioration (PSD) program, the Nonattainment New Source Review (NNSR) program, and Title V permitting program. IPAA/AXPC believes that establishing certainty regarding source determinations provides an important benefit to the permitting process. Below are a series of recommendations and comments that address IPAA/AXPC's concerns regarding the EPA proposal. However, at the outset, IPAA/AXPC would observe that, while there have been some specific issues associated with past interpretations of oil and natural gas production sources, the issue of source determination applies to all stationary sources.

Similarly, this issue of changing the structure of source determination must conform to the constraints of past interpretations. As EPA characterizes its actions on source determination in the Federal Register:

> Adhering to the statutory language in CAA section 111(a)(3), we have defined the term ''stationary source'' to mean ''any building, structure, facility, or installation which emits or may emit a regulated NSR pollutant'' [40 CFR 52.21(b)(5); 40 CFR 51.165(a)(1)(i); 40 CFR 51.166(b)(5)]. We have then further defined the four statutory terms ''building, structure, facility, or installation'' collectively in our NSR regulations to mean ''all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control),'' where the ''same industrial grouping'' refers to the two-digit Standard Industrial Classification code [40 CFR 52.21(b)(6); 40 CFR 51.165(a)(1)(ii); 40 CFR 51.166(b)(6)]. These three regulatory factors: (1) Same industrial grouping; (2) location on contiguous or adjacent properties; and (3) under the control of the same person or persons must be evaluated on a case-by-case basis for each permitting decision.[60]

EPA needs to confirm clearly that its actions on source determination operate within this larger framework.

EPA presents two approaches to source determination. These comments focus principally on Option A – defining the source based on proximity – because IPAA/AXPC strongly opposes Option B, which includes exclusively functionally interrelated equipment.

Much of the history of the source determination question for oil and natural gas production occurred prior to the significant shift in development to shale formations and the evolution of technology that has been so successfully applied to produce those resources. These changes in the nature of oil and natural gas development alter the physical aspects of producing operations. Oil and natural gas production operations have moved from a framework where numerous vertical wells were drilled in developing a resource play to a framework where development relies on significant horizontal legs providing access to the resources. Correspondingly, a typical well site will now include numerous individual wells ranging from six

[60] Source Determination for Certain Emission Units in the Oil and Natural Gas Section, 80 Fed. Reg. 56,579, 56,580 (Sept. 18, 2015) (to be codified at 40 C.F.R. pts. 49, 51, 52, *et al.*).

to twelve to, sometimes, twenty. As a result, the concepts that drove past EPA actions to consider source determination approaches that aggregate multiple well sites together – essentially the "daisy chaining" concept the EPA seeks to avoid in this proposal – no longer reflect the industry's common practices.

Similarly important, the regulatory structure that affects oil and natural gas production has changed significantly. Since the beginning of 2015, the industry has been subjected to NSPS requirements on completions of new hydraulically fractured natural gas wells, pneumatic controllers, and storage vessels. Currently pending are proposals to regulate new hydraulically fractured oil wells, pneumatic pumps, compressors, and fugitive emissions. These regulations apply to virtually every new well site and manage the emissions. Consequently, the issue of emissions management is essentially settled, and the principle issue of the source determination rule will be the regulatory burden for the specific permitting programs of the proposals – PSD, NNSR, and Title V. Because emissions are not the driving factor in the decision, EPA should move toward limiting burdens rather than expanding them.

These factors shape our view that Option A – *Define Source Based on Proximity (Similar to the NESHAP)* – is the far better framework to address source determination. As EPA characterizes Option A:

> Under the first, and currently preferred, option for which the EPA is taking comment, the EPA proposes to define "adjacent" such that the source is similar to that in the NESHAP for this industry, Subpart HH, National Emissions Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities (40 CFR 63.760). Under this option, the "source" for oil and natural gas sector activities is presumed to be limited to the emitting activities at the surface site, and other emitting activities will be considered "adjacent" if they are proximate. Thus, under this first option, two or more surface sites must be considered as a single source if they share the same SIC code, are under common control, and are contiguous or are located within a short distance of one another.
>
> We prefer this option because we believe that a definition that centers on a surface site is familiar to the industry and the regulators because of the current NESHAP requirements, so it will streamline permitting. We also believe that a definition focused on a surface site most closely represents the common sense notion of a plant for this industry category. Surface sites that are not in close proximity to one another may be on a separate lease which may not align with the common sense notion of a single plant. In addition, we believe that this definition is consistent with Congress' intent, at least as they expressed it with regard to [hazardous air pollutants (]HAPs[)], as discussed previously.[61]

IPAA/AXPC essentially agrees with EPA's characterization and its rationale. Where IPAA/AXPC differs relates to an issue where EPA seeks specific comments – whether it is

[61] *Id.* at 56,586-7.

appropriate to establish a specific distance within which to consider multiple surface sites as a single source, and if so, what that distance should be. EPA is proposing a distance of a ¼ mile. IPAA/AXPC believes that EPA should, instead, adhere to the approach it has used in the NESHAP formulation. EPA should base its final factor on sites being contiguous in addition to sharing the same SIC Code and being under common control.

This approach improves on the proximity concept because it avoids picking an arbitrary distance, such as a ¼ mile. Moreover, it readily addresses another issue that EPA raises – "daisy-chaining". EPA is correct to be concerned that linking one site to another through its proximity invites the opportunity to link a third or a fourth or more sites solely on the basis of proximity. There is no value in daisy-chaining since the individual sites are each subject to the emissions management requirements under the appropriate NSPS or whatever additional regulations apply.

If, however, EPA persists in utilizing a specific distance, it is correct that some states use ¼ of a mile as a bright line to exclude needless source determinations for facilities outside that distance. However, most states then conduct a case-by-case source determination for facilities inside the ¼ mile based on proximity and the "common sense notion of a plant." Therefore, if EPA persists in utilizing a specific distance, it should follow the example of most of the oil and gas producing states and use the bright line to trigger a case-by-case source determination inside that bright line. It is also important to recognize that using an arbitrary distance raises questions of daisy-chaining, and EPA should have language either in the rule or the preamble to state that facilities should not be daisy-chained. EPA has also asked from where a specific distance should be measured. We suggest that the distance be based on the center of the new source triggering the source determination to the center of any nearby facility.

EPA should reject Option B – *Define Source To Include Exclusively Functionally Interrelated Equipment*. Option B essentially invites daisy-chaining. It creates the opportunity to link multiple facilities regardless of the distances between them. For example, as EPA states "[e]xclusive functional interrelatedness might be shown by connection via a pipeline or other means, because of the physical connection between the equipment."[62]

This characterization largely parrots the circumstances in the *Summit Petroleum Corp. v. U. S. Environmental Protection Agency*, 690 F.3d 733 (6th Cir. 2012) case. In this case, as EPA describes in its discussion of these proposals:

> In the decision, the Court said that the EPA's use of interrelatedness in determining whether sources were "adjacent" is unreasonable and contrary to the plain meaning of the term as currently used in EPA's regulations. The two judges in the majority found that the term "adjacent" was unambiguous and its plain meaning related only to physical proximity, and thus could not include

[62] *Id.* at 56,587.

> consideration of functional interrelatedness. The EPA sought rehearing of the Court's decision, but that request was denied.[63]

Why EPA would suggest moving back toward this judicially rejected approach is unfathomable. More importantly, it does not create any environmental benefits, because, as stated above, the existence of the current and proposed EPA oil and natural gas production regulatory requirements would apply to the separate facilities. Option B would only create substantially expanded regulatory burdens.

In conclusion, IPAA/AXPC believes that EPA's appropriate choice is a modified Option A relying on the use of a contiguous border to aggregate sources if aggregation is appropriate. To facilitate clarity on this issue, IPAA/AXPC suggests adding the following definition where appropriate in the Code of Federal Regulations:

> "Contiguous or adjacent properties" mean surface areas with an affixed building, structure, facility or installation including permanently graded or cleared areas for such building, structure, facility or installation, that share an edge/boundary, physically touch, and are adjoining or physically abutting.

CONCLUSION

IPAA/AXPC values the opportunity to comment on the above referenced regulatory proposals. The oil and natural gas production industry has worked closely with EPA over the past decade to promulgate reasonable, cost-effective regulations on air emissions. While industry objected to various aspects of the Subpart OOOO regulations controlling VOC emissions from various sources within the oil and natural gas sector, through the administrative reconsideration process and revisions to Subpart OOOO, many of the issues have been addressed without protracted and costly litigation. The proposed Subpart OOOOa and CTG regulations seem to represent a departure from a willingness on the part of this Administration to promulgate reasonable, cost-effective, and most importantly, needed regulations.

EPA's pollutant of concern is methane. Unlike other "pollutants" and other industrial "products," methane is not treated as a pollutant in the oil and natural gas industry – it is a valuable product. Unlike other industries, market forces are constantly at work to minimize what EPA views as a pollutant and our industry views as a product. The fact methane is a primary constituent of what this industry produces explains, in large part, why emissions from the exploration and production segment of the oil and natural gas sector have gone down while production has gone up (see Section I above). In reality, most of the reductions are a function of voluntary measures by producers to retain/capture methane or state regulatory programs where oil and natural gas production has increased dramatically in the past decade.

A central theme to IPAA/AXPC's comments is that the proposed Subpart OOOOa regulations are unnecessary and the CTG proposed regulations are, at best, premature. The

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[63] *Id.* at 56,584.

EPA's legal foundation and basis for the proposed Subpart OOOOa and CTG regulations are dubious and invite legal challenge. It is arbitrary and capricious for EPA to base its proposed methane regulations (NSPS and CTG) on a model that predicts the social cost of methane. The irony is that EPA can accomplish a majority of its goals with modifications to existing regulations and attainment of the current Ozone NAAQS. The cost of EPA's proposed NSPS and CTG is not justified.

A. Proposed Methane New Source Performance Standards Summary Comments

- Regulations cannot be based on what EPA "believe[s]" "the industry can bear . . . and survive."[64]
- EPA's "consistency," patchwork "endangerment finding," and global warming concerns do not warrant direct regulation of methane emissions from the oil and natural gas sector.
- EPA's failure to evaluate the cost associated with the potential regulation of existing sources under Section 111(d) is arbitrary and capricious.
- States (and operations within those states) should not be penalized for taking early action to address emissions from the oil and natural gas sector, i.e., compliance with essentially equivalent state programs should be deemed compliance with the finalized Subpart OOOOa regulations.
- EPA's focus on fugitive emissions at well sites and compressor stations is premature and not supported by reliable cost/benefit data.
    - EPA's request for input and comment on numerous aspects of the proposed regulations is indicative of an issue that regulators and industry are still learning to address.
    - The "corporate fugitive management program" is a logical way to address the issue, but regulators and companies need time to determine what such a program should look like.
    - EPA's cost-effectiveness analysis for the proposed regulatory package suffers from shortcomings on both sides of the equation: for the reasons set forth above, the costs are understated and the benefits are overstated or unsupported.
    - States with the most active shale plays are learning valuable information on how to reduce fugitive emissions. EPA should not rush to judgement and establish federal standards that will be inconsistent, duplicative and potentially unnecessary because of state efforts.
    - For the reasons stated above, EPA should not dictate a specific technology for determining "leaks." OGI may be appropriate in certain instances, but EPA's selection of one technology is arbitrary and capricious.
    - EPA's proposed approach to determining the frequency of LDAR surveys based on percentage of leaking components demonstrates its lack of understanding of the issues associated with fugitive emissions. As discussed above, EPA's

[64] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,629 (Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60)

  - proposed regulations would impose significant costs on the industry with dubious environmental benefit.
  - IPAA/AXPC supports EPA's proposed exclusions but seeks clarification that the 15 boe exclusion also serves as an off ramp to reduce the burden of the proposed regulations.
- Oil well RECs are not the same as RECs at natural gas wells.
  - IPAA/AXPC questions if EPA has documented new information to justify the cost-effectiveness of RECs on oil wells. The economics and engineering limitations at oil wells are different than natural gas wells, and EPA has failed to adequately differentiate between the two and justify RECs at oil wells.
  - IPAA/AXPC supports the limited exclusions to the oil well REC requirements but suggests clarification as to the requirements associated with noncombustible gas.
- EPA's proposed regulation of pneumatic pumps fails to adequately reflect the complexity, cost, and safety issues associated with sending captured natural gas to an existing combustion device. IPAA/AXPC believes that if the costs associated with such complexity were adequately reflected, the proposed regulations would not be cost effective.
- IPAA/AXPC supports EPA's proposed regulations that indicate the compressor rules do not apply to compressors at the wellsite but requests clarification that a similar exclusion applies under the proposed CTG.

B. Proposed CTG Summary Comments

- The CTG regulations must be based on a technological analysis for RACM instead of arbitrarily transposing new source BSER requirements to existing sources.
- The CTG regulations need to recognize differences across the oil and natural gas production industry that recognize size and scope of operations.
  - Marginal oil and natural gas production facilities should be excluded from all of the CTG.
- The CTG regulations must be based on their applicability to manage VOC emissions in Ozone NAAQS nonattainment areas.
  - EPA has failed to provide justification for the CTG as necessary for Ozone NAAQS attainment and, in reality, EPA's projections of Ozone NAAQS attainment in 2025 demonstrates the CTG are not necessary.
  - Implementation of the CTG in the absence of a demonstrated need is counterproductive and unnecessarily constrains economic growth.

C. Proposed Point Source Determination Summary Comments

- EPA should adopt a Source Determination definition that adheres to the approach it has used in the NESHAP formulation. EPA should base its final factor on sites being contiguous in addition to sharing the same SIC Code and being under common control.
- EPA should reject the use of functionally related equipment as a consideration in adopting revisions to its Source Determination definition.

If EPA has any questions or concerns, please do not hesitate to contact us.

Sincerely,

Lee Fuller
Executive Vice President
Independent Petroleum Association of America

V. Bruce Thompson
President
American Exploration & Production Council

Cc: Janet McCabe, EPA
Joe Goffman, EPA
Peter Tsirigotis, EPA
David Cozzie, EPA
Bruce Moore, EPA
Cheryl Vetter, EPA
Chris Stoneman, EPA
Charlene Spells, EPA

ATTACHMENT A

ACRONYM INDEX

AAPL	American Association of Professional Landmen
AEO	Annual Energy Outlook
AESC	Association of Energy Service Companies
ANGA	America's Natural Gas Alliance
API	American Petroleum Institute
AR5	Fifth Assessment Report
AVO	audio/visual/olfactory
AWEA	American Wind Energy Association
AXPC	American Exploration and Production Council
boe	barrels of oil equivalent
BSER	best system of emission reductions
CAA or Act	Clean Air Act
CMSA	Consolidated Metropolitan Statistical Area
CTG	Control Technique Guidelines
EIA	Energy Information Administration
FLIR	forward looking infrared
GHG	Greenhouse Gas
GOR	gas-to-oil ratio
HAPs	hazardous air pollutants
IADC	International Association of Drilling Contractors
IAGC	International Association of Geophysical Contractors
IPAA	Independent Petroleum Association of America
IPCC	Intergovernmental Panel on Climate Change
LDAR	leak detection and repair

NAAQS	National Ambient Air Quality Standards
NCA3	2014 National Climate Assessment, Climate Change Impacts in the United States
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGO	non-governmental organizations
NNSR	Nonattainment New Source Review
NSPS	New Source Performance Standards
NSWA	National Stripper Well Association
NYMEX	New York Mercantile Exchange
OGI	optical gas imaging
OTR	ozone transport regions
PESA	Petroleum Equipment & Services Association
PSD	Prevention of Significant Deterioration
RACM	Reasonably Available Control Measures
RACT	reasonably available control technology
RECs	reduced emissions completions
RIA	Regulatory Impact Analysis
SCADA	supervisory control and data acquisition
SCC	social cost of carbon
SC-CH_4	social cost of methane
SIC	Standard Industrial Classification
SIPs	State Implementation Plans
TSD	Technical Support Document
USG	United States Government
USGCRP	U.S. Global Change Research Program
USOGA	U.S. Oil & Gas Association

VOC	Volatile Organic Compound
VRU	vapor recovery units
WEA	Western Energy Alliance

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August 2, 2016

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

Re: Request for Administrative Reconsideration EPA's Final Rule "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources"

Dear Administrator McCarthy:

The following trade associations hereby submit this petition for administrative reconsideration of the final rule entitled "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources," published at 81 Fed. Reg. 35824 (June 3, 2016) ("Subpart OOOOa" or "Methane NSPS"). We request that you take the time to review what and who these trade associations represent and not simply jump to the issues we are seeking reconsideration of. Many of these trade associations have been around since or before the 1950s. The trade associations represent the "independent" exploration and production companies – from the "mom and pop" operations to some of the larger producers in the country – but that is all they do and it is all they know. Subpart OOOOa, as finalized, will have a disproportionate impact on independents and especially independents that constitute "small business" under the Regulatory Flexibility Act. The issues raised in this petition fall into two categories: 1) issues that are entitled to reconsideration under Section 307(d)(7)(B) of the Clean Air Act ("CAA"), 42 U.S.C. § 7607(d)(7)(B), where it is impracticable to raise an objection during the period of public comment or if the grounds for such an objection arise after the public comment period (but within the time specified for judicial review), and if such objections are of central relevance to the outcome of the rule; and 2) issues the independents commented on, either through their trade association or as an individual company, that the U.S. Environmental Protection Agency ("EPA" or "Agency") failed to address in the final rule and that will have devastating impacts to the exploration and production segment of the industry if not addressed.

The national and state level trade associations joining in and filing this petition for reconsideration, collectively referred to as the "Independent Associations," are described below.

The Independent Petroleum Association of America ("IPAA") is an incorporated trade association that represents thousands of independent oil and natural gas producers and service companies across the United States that are active in the exploration and production segment of the industry, which often involves the hydraulic fracturing of wells. IPAA serves as an informed voice for the exploration and production segment of the industry, and advocates its members' views before the United States Congress, the Administration and federal agencies.

The American Exploration & Production Council ("AXPC") is an incorporated national trade association representing 29 of America's largest and most active independent oil and natural gas exploration and production companies. AXPC members are "independent" in that their operations are limited to exploration for and the production of oil and natural gas. Moreover, its members operate autonomously, unlike their fully integrated counterparts, which operate in additional segments of the energy business, such as downstream refining and marketing. AXPC members are leaders in developing and applying the innovative and advanced technologies necessary to explore for and produce oil and natural gas, both offshore and onshore, from non-conventional sources in environmentally responsible ways.

The Domestic Energy Producers Alliance ("DEPA") is a nationwide collaboration of 25 coalition associations, representing about 10,000 individuals and companies engaged in domestic onshore oil and natural gas production and exploration. Founded in 2009, DEPA gives a loud, clear voice to the majority of individuals and companies responsible for enduring work to secure our nation's energy future.

The Eastern Kansas Oil & Gas Association ("EKOGA") is a nonprofit organization founded in 1957 to become a unified voice representing the unique interests of eastern Kansas oil and gas producers, service companies, suppliers and royalty owners on matters involving oil and gas regulations, safety standards, environmental concerns and other energy related issues.

The Illinois Oil & Gas Association ("IOGA") was organized in 1944 to provide an agency through which oil and gas producers, land owners, royalty owners, and others who may be directly or indirectly affected by or interested in oil and gas development and production in Illinois, may protect, preserve and advance their common interests.

The Independent Oil and Gas Association of West Virginia, Inc. ("IOGA-WV"), is a statewide nonprofit trade association that represents companies engaged in the extraction and production of natural gas and oil in West Virginia and the companies that support these extraction and production activities. IOGA-WV was formed to promote and protect a strong, competitive, and capable independent natural gas and oil producing industry in West Virginia, as well as the natural environment of their state.

The Indiana Oil and Gas Association ("INOGA") has a rich history of involvement in the exploration and development of hydrocarbons in the State of Indiana. INOGA was formed in 1942 and historically has been an all-volunteer organization principally made up of representatives of oil and gas exploration and development companies (operators), however, it has enjoyed support and membership from pipeline, refinery, land acquisition, service, supply, legal, engineering and geologic companies or individuals. INOGA has been an active representative for the upstream oil and gas industry in Indiana and provides a common forum for this group. INOGA represents its membership on issues of state, federal, and local regulation/legislation that has, does and will affect the business of this industry. INOGA is a

501(c)(6) trade association incorporated as Non-Profit Domestic Corporation under the statutes of Indiana.

Since 1940, the International Association of Drilling Contractors ("IADC") has exclusively represented the worldwide oil and gas drilling industry. IADC's contract-drilling members own most of the world's land and offshore drilling units that drill the vast majority of the wells producing the planet's oil and gas. IADC's membership also includes oil-and-gas producers, and manufacturers and suppliers of oilfield equipment and services. Through conferences, training seminars, print and electronic publications, and a comprehensive network of technical publications, IADC continually fosters education and communication within the upstream petroleum industry.

The Kansas Independent Oil & Gas Association ("KIOGA") is a nonprofit organization founded in 1937 to represent the interests of oil and gas producers in Kansas, as well as allied service and supply companies. Today, KIOGA is a trade association with over 4,200 members involved in all aspects of the exploration, production, and development of crude oil and natural gas resources.

The Kentucky Oil & Gas Association ("KOGA") was formed in 1931 to represent the interests of Kentucky's crude oil and natural gas industry, and more particularly, the independent crude oil and natural gas operators as well as the businesses that support the industry. KOGA is comprised of 220 companies which consist of over 600 member representatives that are directly related to the crude oil and natural gas industry in Kentucky.

The Michigan Oil And Gas Association ("MOGA") represents the exploration, drilling, production, transportation, processing, and storage of crude oil and natural gas in the State of Michigan. MOGA has nearly 850 members including independent oil companies, major oil companies, the exploration arms of various utility companies, diverse service companies, and individuals. Organized in 1934, MOGA monitors the pulse of the Michigan oil and gas industry as well as its political, regulatory, and legislative interest in the state and the nation's capital. MOGA is the collective voice of the petroleum industry in Michigan, speaking to the problems and issues facing the various companies involved in the state's crude oil and natural gas business.

The National Stripper Well Association ("NSWA") was founded in 1934 as the only national association *solely* representing the interests of the nation's smallest and most economically-vulnerable oil and natural gas wells before Congress, the Administration and the Federal bureaucracies. It is the belief of NSWA that producers, owners, and operators of marginally-producing oil and gas wells have a unique set of needs and concerns regarding federal legislation and regulation. NSWA is a member based trade association with nearly 800 members nationwide across 43 states.

The North Dakota Petroleum Council ("NDPC") is a trade association representing more than 590 companies involved in all aspects of the oil and gas industry, including oil and gas production, refining, pipeline, transportation, and storage, as well as mineral leasing, consulting, legal work, and oil field service activities in North Dakota, South Dakota, and the Rocky

Mountain Region. Established in 1952, NDPC's mission is to promote and enhance the discovery, development, production, transportation, refining, conservation, and marketing of oil and gas in North Dakota, South Dakota, and the Rocky Mountain region; to promote opportunities for open discussion, lawful interchange of information, and education concerning the petroleum industry; to monitor and influence legislative and regulatory activities on the state and national level; and to accumulate and disseminate information concerning the petroleum industry to foster the best interests of the public and industry.

The Ohio Oil & Gas Association ("OOGA") is a trade association with over 2,600 members involved in all aspects of the exploration, production, and development of crude oil and natural gas resources within the State of Ohio. OOGA represents the people and companies directly responsible for the production of crude oil, natural gas, and associated products in Ohio.

Founded in 1955, the Oklahoma Independent Petroleum Association ("OIPA") represents more than 2,500 individuals and companies from Oklahoma's oil and natural gas industry. Established by independent oil and natural gas producers hoping to provide a unified voice for the industry, OIPA is the state's largest oil and natural gas association and one of the industry's strongest advocacy groups.

The Pennsylvania Independent Oil & Gas Association ("PIOGA") is a non-profit corporation that was initially formed in 1978 as the Independent Oil and Gas Association of Pennsylvania ("IOGA of PA") to represent the interests of smaller independent producers of Pennsylvania natural gas from conventional limestone and sandstone formations. Effective April 1, 2010, IOGA of PA and another Pennsylvania trade association representing conventional oil and natural gas producers, Pennsylvania Oil and Gas Association ("POGAM"), merged and the name of the merged organization changed to its present name. PIOGA's membership currently is approximately 500 members: oil and natural gas producers developing both conventional and unconventional formations in Pennsylvania; drilling contractors; service companies; engineering companies; manufacturers; marketers; Pennsylvania Public Utility Commission-licensed natural gas suppliers ("NGSs"); professional firms and consultants; and royalty owners. PIOGA promotes the interests of its members in environmentally responsible oil and natural gas operations, as well as the development of competitive markets and additional uses for Pennsylvania-produced natural gas.

The Texas Alliance of Energy Producers ("Texas Alliance") became a statewide organization in 2000 with the merger of two of the oldest oil & gas associations in the nation: the North Texas Oil & Gas Association and the West Central Texas Oil & Gas Association. The Texas Alliance is now the largest statewide oil and gas association in the country representing Independents. With members in 34 states, the Texas Alliance works on behalf of our members at the local, state, and federal levels on issues vital to the industry.

The Texas Independent Producers & Royalty Owners Association ("TIPRO") is a trade association representing the interests of 3,000 independent oil and natural gas producers and royalty owners throughout Texas. As one of the nation's largest statewide associations representing both independent producers and royalty owners, members include small family businesses, the largest, publicly-traded independent producers, and mineral owners, estates, and trusts. Members of TIPRO are responsible for producing more than 85 percent of the natural gas and 70 percent of the oil within Texas, and own mineral interests in millions of acres across the state.

Chartered in 1915, the West Virginia Oil and Natural Gas Association ("WVONGA") is one of the oldest trade organizations in the State, and is the only association that serves the entire oil and gas industry. The activities of our members include construction, environmental services, drilling, completion, gathering, transporting, distribution, and processing.

The Independent Associations respectfully request the Agency reconsider the following issues.

A. SECTION 307(D)(7)(B) RECONSIDERATION ISSUES

1. The low production well (15 barrels of oil equivalent ("boe")/day) exemption from leak detection and repair ("LDAR") and reduced emission completions ("RECs") requirements should be reinstated in the final rule and the requirements regarding low production wells should be stayed pending reconsideration.

In the proposed rule, EPA sought comment on and proposed to exclude low production wells (i.e., those with an average daily production of 15 barrel equivalents or less per day) from REC and LDAR requirements. 80 Fed. Reg. 56633-34, 56639, 56665 (Sept. 18, 2015). The trades representing the independents uniformly supported the low production well exemptions. Based on the preamble discussion of the low production well exemption, EPA listened to, understood, and accepted the arguments and comments set forth by "small entities" during the Small Business Advocacy Review Panel ("Panel") process, in compliance with Section 609(b) of the Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 ("SBREFA"). Small entity representatives ("SERs"), including trade associations that are part of this petition, met with the Panel, which included EPA personnel, on May 19, 2015, and June 18, 2015, and submitted written comments. The SERs' message was clear – the potential REC and LDAR requirements would be the most onerous aspect of any additional controls on their operations. The SERs explained how and why these potential requirements would disproportionality impact small entities. The SERs explained the physical differences associated with low production wells (e.g., primarily pressure and volume) and the marginal profitability of low production wells. EPA seemed to "get it" and stated in the preamble:

> We believe the lower production associated with these wells [low production wells] would generally result in lower fugitive emissions. It is our understanding that fugitive emissions at low production well sites are inherently low and that such well sites are mostly owned and operated by small businesses. We are concerned about the burden of the fugitive emission requirement

> on small businesses, in particular where there is little emission reduction to be achieved.

80 Fed. Reg. 56639. Numerous oil and natural gas trade associations, including many of the parties to this petition filed comments in support of the exemptions and the rationale behind them.

Despite the information provided to EPA during the SBREFA process and Final Report of the Panel, EPA reversed course in the version of Subpart OOOOa and did not provide the low production exemption from either the REC or LDAR requirements. In the preamble to Subpart OOOOa that "one commenter" stated that low production wells have the "potential" to emit high fugitive emissions; "another commenter" stated that the LDAR survey should be conducted quarterly or monthly; and "one commenter" provided an estimate that a "significant" number of wells would be excluded under the low production well exemption. What appears to be EPA's principal reason for reversing course is that

> [S]takeholders indicated that well site fugitive emissions are not correlated with levels of production, but rather based on the number of pieces of equipment and components. Therefore, we believe that the fugitive emissions from low production and non-low production well sites are comparable.

81 Fed. Reg. 35856. EPA's rationale, that fugitive emissions are a function of the number and types of equipment, and not operating parameters such as pressure and volume, is inconsistent with EPA's justification for what constitutes a "modification" for an existing well site. EPA assumes that fracturing or refracturing an existing well will increase emissions because of the additional production, i.e., the additional pressure and volume. EPA cannot ignore the laws of physics to the detriment of low production wells in one instance and then "honor" them in another context to eliminate an "emissions increase" requirement in the traditional definition of "modification."

The estimation or correlation of fugitive emissions with the number or types of components at low production versus non-low production wells was not discussed during the Panel process nor was comment sought by EPA in the proposed rule. If EPA proposed to correlate fugitive emissions at low production well sites with the number or types of components – in place of operating parameters such as line pressure and volume, independents would have been put on notice that additional information and comments were needed on the issue. No such comment was sought and EPA rationale and revocation of the low production well exemption is confounding. An administrative stay of the REC and LDAR requirements to low production wells is warranted pending outcome of the reconsideration proceeding. Although the effective date of the requirements has been extended 180 days, the impact of the regulations is immediate on low production wells. The marginal profitability will mean that many wells will be shut in instead of making the investment to conduct LDAR surveys. Similarly, low production wells that are currently in the planning stage will be reevaluated to take into consideration the additional costs of RECs and it is likely that the plans to drill many wells will be scrapped. For the reasons set forth above, it is appropriate for EPA to grant reconsideration of this issue.

2. The requirement in Section 60.5375a of Subpart OOOOa that requires a separator be "onsite during the entirety of the flowback period" was not part of the proposal and imposes an unnecessary cost on many conventional wells drilled by independents.

From the inception of the Subpart OOOO rulemaking, independent operators have informed the Agency that operating parameters during flowback of certain hydraulically fractured wells, often what is referred to as "conventional" wells, are such that a separator does not "work" – or as EPA has focused on is not technically feasible. EPA initially seems to understand this point and states:

> … we do not have sufficient data to consistently and accurately identify the subcategory or types of wells for which these circumstances occur regularly or what criteria would be used as the basis for an exemption to the REC requirement such that a separator would not be required to be onsite for these specific well completions. In order to accommodate these concerns raised by commenters, the final rule requires a separator to be onsite during the entire flowback period for subcategory 1 wells (i.e., non-exploratory or non-delineation wells, also known as development wells), but does not require performance of REC where a separator cannot function. We anticipate a subcategory 1 well to be producing or near other producing wells. We therefore anticipate REC equipment (including separators) to be onsite or nearby, or that any separator brought onsite or nearby can be put to use. For the reason stated above, we do not believe that requiring a separator onsite would incur cost with no environmental benefit.

81 Fed. Reg. 35881. Independent Associations take issue with the conclusion that requiring a separator onsite throughout the entire flowback period would incur no cost. The cost of having the separator on site is a significant cost and could be a limitation on the operations of certain operators. The existing regulations make clear that a separator must be utilized during the separation flowback stage and EPA has increased the record keeping and monitoring associated with the different stages of flow back. In addition to these requirements, there is the general duty clause to reduce emissions. The requirement to have a separator onsite throughout the flowback process is an unnecessary cost to many independent operators that provides no economic benefit. The proposed rule did not contemplate requiring a separator to be onsite throughout the flowback process and in fact inferred just the opposite. For the reasons set forth above, it is appropriate for EPA to grant reconsideration of this issue.

3. Subpart OOOOa added a variety of requirements associated with "technical infeasibility" that were not purposed or even mentioned in the proposed rule

that increase the cost of compliance with disproportionally impacts on independent operators.

While the Agency has appropriately accepted the concept that it is not technically feasible to implement certain controls, EPA added a number of requirements in Subpart OOOOa that were not proposed or discussed in the proposed rule:

- The final rule requires that Professional Engineers ("PE") certify connections of pneumatic pumps (§60.5393a) or closed vent systems (§60.5411a(d) are not technically feasible at brownfield sites. The certification by a PE will add considerable cost with no demonstrated benefits. As with many of these requirements. the independent operators do not have the ability in-house to meet these requirements and are dependent on third-party contractors. As EPA pushes the envelope on new/additional requirements, economies of scale favor the larger operators and to the extent the contractors are available for hire, it comes at a premium cost for the smaller entities and/or independent operators.
- Without discussion in the proposed rule, the Agency has also removed the "technical infeasibility" option for controls at "greenfields." Neither the proposed rule nor Subpart OOOOa define what constitutes a brownfield versus a greenfield. At some point in time a greenfield becomes a brownfield. Not only does the proposed rule fail to mention the concept of brownfield versus greenfield, Subpart OOOOa fails to provide any differentiation.
- The additional recordkeeping requirements added in Subpart OOOOa, at end of §60.5420a(c)(1)(iii)(A), associated with technical infeasibility, which were not part of the proposed rule, demonstrates that the Agency fails to understand that such requirements disproportionally impact small entities and many independent producers and operators.

The additional requirements associated with technical infeasibility were not only not addressed in the proposed rule, but the Agency failed to consider and address the disproportionate impact they would have on independent operators.

B. ADDITIONAL ISSUES IN NEED OF REVISION

The following issues were arguably addressed in some manner during the SBREFA and/or notice and comment process, but based on a review of the record, the Independent Associations believe they warrant additional discussion. The Independent Associations will provide the Agency additional information on these issues of concern.

1. The definition of "modification" as it relates to refractured wells and the LDAR requirements needs to be clarified and changed. The refracturing of wells does not necessarily mean emissions will increase. Emissions must increase to meet the NSPS definition of modification. As currently defined, Subpart OOOOa would unjustifiably subject "existing sources" that have not necessarily been modified to extensive and costly requirements.

2. Certain oil wells should be exempt from the LDAR requirements. Similarly, there should be a different definition of "low pressure well."

3. There should be an "off ramp" for the LDAR requirements when existing wells or new wells become "low production" or marginal wells.

4. Although Subpart OOOOa provides a state equivalency process for LDAR programs, the procedure set forth in the regulations (§60.5398a) is overly burdensome to the point that states are unlikely to avail themselves of the provisions.

5. The digital/video LDAR related requirements (§60.5420a) are unnecessary and should be removed.

6. EPA should reinstate options to reduce the emission surveys to annual surveys. While certain operators might prefer the consistency of bi-annual surveys, many independent operators and small entities would still benefit from the ability to reduce survey frequency by demonstrating few/no leaks during consecutive surveys.

7. Extended implementation periods are necessary and warranted for small entities that lack the bargaining power and resources (and the in-house capabilities) to contract with consultants to undertake the surveys, testing and documentation required by Subpart OOOOa. .

As indicated above, the Independent Associations will provide additional information on the issues raised above. In the interim, if the EPA has any questions or concerns, please do not hesitate to contact me.

Respectfully submitted,

James D. Elliott

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cc: Janet McCabe, EPA
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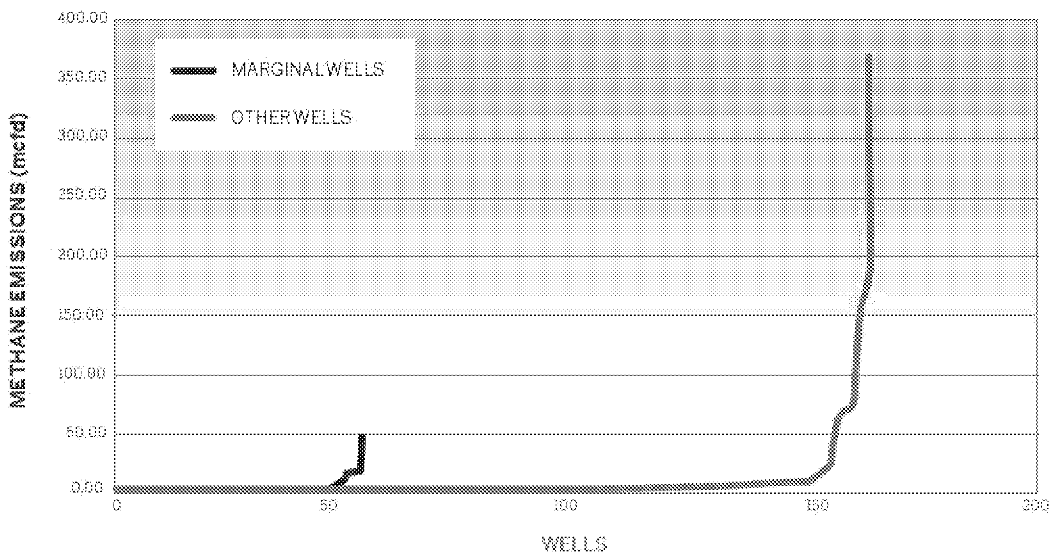
Manipulating Data to Create the Illusion That Low Producing Wells Are "Super-Emitters"

This document addresses data manipulation issues in the environmentalist study submitted to the rulemaking proposal for Subpart OOOOa to distort the role of low producing wells regarding methane emissions. This study was then characterized as the basis for removing the low producing well exclusion for the Subpart OOOOa fugitive emissions program initially proposed by the Environmental Protection Agency (EPA).

Background

Initially, it is important to understand that this study used data from a number of different studies to create its arguments. All of the underlying studies generated their data by driving vehicles with samplers downwind of production sites, hunting for methane plumes. None of them used samples taken on the production site. This creates two issues. First, it measures everything emitted at the site – fugitive emissions and permitted vents. Second, the data are collected over minutes – maybe over an hour – but not over a day. The data in the study are presented as if they were daily emissions but the studies merely scale up hourly estimates. Consequently, an emission that might occur for several hours, but not the full day, would be overstated.

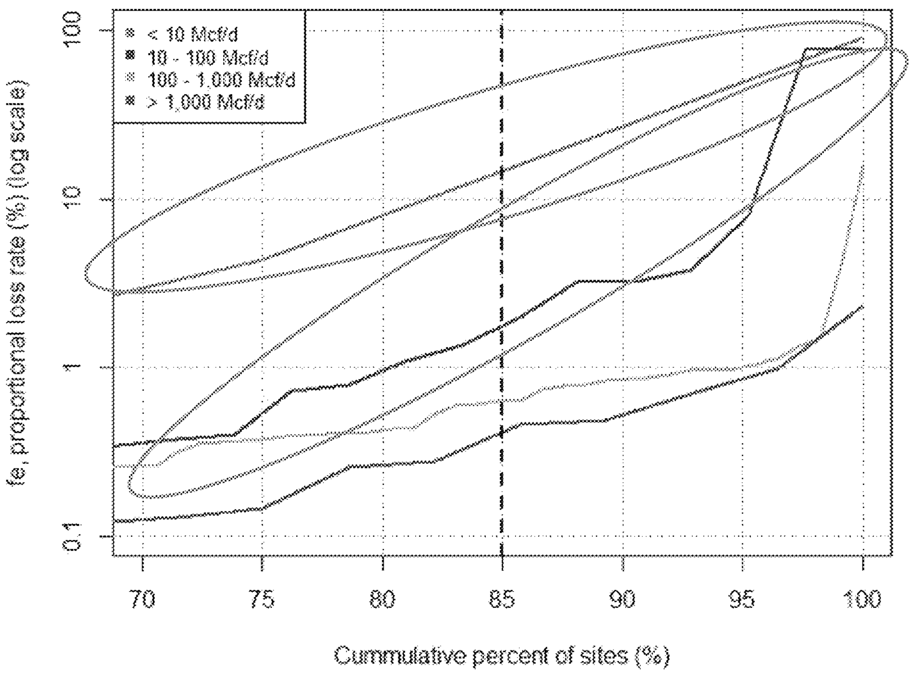
Before turning further to describe the submitted study, it is useful to look at the same data using a direct graph of emissions. In this graph, marginal wells are those with production volumes of 90 mcfd or less.



This graph is consistent with information from other studies showing that a small portion of wells have an emission profile for some reason with high emissions and most wells have really low emissions. Importantly, it also clearly shows that marginal wells – low producing wells in the context of the regulation – have far smaller emissions. But, since this graph is using the same data as the study, it could also be overstating emissions because of scaling short term emissions to a daily amount.

With this background, turning to the presentation of the same material in the study demonstrates how it was manipulated.

Below is the graphic used to present the data. It would suggest that the worst emitting operations – the "super-emitters" – are the smallest wells (the orange line and the blue line, circled in green). Having directly plotted this data, the obvious issue is how such a result can occur.



It is a busy and confusing graph – it's intended to be. The study uses data analysis tricks to create the appearance that marginal wells are "super-emitters".

First, it shows emissions as a percentage of production rather than actual emissions. Thus, one mcf emitted out of ten mcf produced is 10 percent, but 50 mcf emitted out of 1000 mcf produced is 5 percent. As a result, it skews the perception of the data to imply that low producing wells are large emitters when they are not.

Second, its production volumes are really sales volumes, not the amount extracted from the wellhead. Consequently, a "proportional loss rate" of 50 percent would be the calculated loss divided by the volume sold. If the percentage of loss were calculated based on extracted volumes, the 50 percent "proportional loss rate" would drop to 33 percent because the loss would be added to the sales volume to obtain the extracted volume.

Third, it only shows data from the 70^{th} percentile of information. This excludes all of the virtually zero emissions that dominate the data.

Fourth, it uses a logarithmic scale to present the data. One of the reasons to use logarithmic scales is to flatten curves to make them look more like straight lines.

These observations can be made without conducting an intense investigation of the study. They are obviously intended to contort data to create a specific result. Yet, with all the investigative power at EPA, with all of the research work EPA has conducted, EPA took this contrived study at face value to make its determination to remove the low producing well exclusion in the Subpart OOOOa regulations. That decision – particularly void of any opportunity for public review – should not be allowed to stand.

Environmental Issues in the Oil Patch

Lee O. Fuller

Executive Vice President

The environmental regulatory framework for oil and natural gas production has changed dramatically over the past decade at both federal and state levels. Much of this change reflects the growth in American oil and natural gas production resulting from the broad application of hydraulic fracturing and horizontal drilling to open access to shale gas and shale oil reserves. In the late 1990's and early 2000's, while there were a core of environmentalists opposing hydraulic fracturing, there was a counterweight among a number of environmental advocates that wanted to oppose coal combustion. Those groups supported a transition to natural gas as a step toward an acceptable renewal fuels climate management policy – viewing natural gas as a bridge to the ultimate objective.

By the mid-2000's, hydraulically fractured shale gas could be recognized not as a bridge to the future but as a superhighway of sustainable natural gas reserves for both American consumption and exports throughout the world. This reality coalesced environmental advocates and produced a vendetta toward natural gas – and later toward crude oil – targeting suppression of future development and shutdown of existing production. The scope of what is now commonly called the Keep It in the Ground movement is broad and expanding.

With roots in efforts to attack hydraulic fracturing as an unsafe technology – allegations that have been extensively shown to be egregiously baseless – the Keep It in the Ground agenda expanded. It moved to characterize all oil and natural gas production activities – activities that are no different for conventional production than for fracturing production – as fracturing, to imply that "fractured" natural gas is somehow different, to target not only the production of oil and natural gas but its transportation and use, and – more pertinently for the discussion – to expand its opposition to other environmental management issues. This discussion will primarily address air emissions regulatory issues including methane management.

Framing the Issues

To place the current environmental issues in context, it is necessary to review the past. Air emissions from oil and natural gas operations have not historically been a significant regulatory target. Most of the attention prior to the actions by the Obama Administration were directed toward some specific issues – management of poisonous hydrogen sulfide in sour oil or gas production areas, benzene emissions from glycol dehydrators and a few others. Some production operations in urban ozone nonattainment areas are regulated for Volatile Organic Compounds (VOC). But, because historic oil and natural gas production was largely comprised of rural operations from widely dispersed individual wells, the industry emissions profile did not generate aggressive regulatory initiatives at either the state or federal level.

Unconventional shale oil and natural gas production operations changes the perception of the emissions profile. Unconventional production concentrates the emissions potential. First, the use of horizontal drilling means that a single well can be producing from a geographic distance of a mile or more from the well bore. Second, numerous wells are developed from one site such that any emissions are more concentrated. The issue of emissions perception is important in the context of the regulatory deliberations that are in play because limited analysis exists on the extent of these emissions. Yet, significant regulatory determinations have been made.

These technology changes were taking place at the same time that an array of political and regulatory initiatives was developing.

Initial Actions and Reactions by the Obama Administration

The first of these related to litigation involving the Clean Air Act (CAA) New Source Performance Standards (NSPS) for oil and natural gas production facilities. In January 2009, environmental groups filed an action to compel EPA to act under its CAA mandatory duty to review the oil and natural gas production facilities NSPS. The use of litigation to capture and drive regulatory agendas has been a growing challenge for all federal regulatory agencies. Created in a time when the development of regulations was far less litigious, in the current adversarial climate, agencies cannot realistically complete their regulatory tasks in the time frame envisioned by Congresses of the 1970s. Consequently, they are far more vulnerable to challenges based on failures to meet mandatory deadlines – challenges that are virtually impossible to rebut. Environmental groups use this weak position to attempt to grab control of an agency's regulatory agenda and shift it to their priorities.

In this instance, the CAA requires EPA to consider NSPS revisions for each category of standards every 8 years. EPA has missed this deadline for oil and natural gas production facilities. Unable to defend its position, EPA finalized a consent decree in February 2010 to propose regulations or a decision not to propose regulations in 2011 and finalize action in 2012.

Second, as EPA began its process, the Obama Administration began to embrace the environmentalist opposition to American oil and natural gas production. By early 2012, the Obama Administration had initiated actions by ten different agencies to federalize regulation of American oil and natural gas production. Then, as the election approached, in April 2012, the Obama Administration announced the creation of its Interagency Working Group to Support Safe and Responsible Development of Unconventional Domestic Natural Gas Resources. This Working Group allowed the Obama Administration to manage the diverse agency efforts that had been initiated reflecting the growing importance of American natural gas development in the economy. By the end of 2012, the intensity of federalizing oil and natural gas production regulation had diminished with three regulatory initiatives still active – EPA guidance to restrict the use of diesel fuel in hydraulic fracturing under the Safe Drinking Water Act, Bureau of Land Management (BLM) drilling regulations affecting hydraulically fractured wells, and the EPA CAA NSPS regulations under the consent decree.

Third, while the debate in the early years of the Obama Administration on climate change and greenhouse gases largely focused on carbon dioxide and on large utility coal-fired electric generators, there were elements that targeted oil and natural gas production. One was the ongoing Gas STAR voluntary reduction program that engaged producers to implement technologies to manage primarily methane emissions from their operations. Another was regulatory requirements to report emissions to the EPA Green House Gas Inventory (GHGI). This rulemaking (Subpart W for oil and natural gas systems) demonstrated EPA's limited understanding of the nature of oil and natural gas production operations and the limited analysis that had been applied to identify air emissions associated with the industry.

EPA finalized its oil and natural gas production facilities NSPS in 2012. They addressed oil and natural gas production, natural gas processing, production gathering and boosting stations, and natural gas compressor station. The oil and natural gas production regulations target the reduction of VOC from fractured natural gas wells, from oil wells, and from storage vessels. They specifically included reduced emissions completion (REC or Green Completion) limitations for fractured natural gas wells, pneumatic controllers from oil and natural gas wells, and oil and natural gas liquids storage vessels. In general, for the oil and natural gas production NSPS regulation – Subpart OOOO – EPA utilized the technologies that had been a part of the Gas STAR program to fulfill the Best System of Emissions Reduction (BSER) requirements of NSPS. However, the ever-present challenge of developing accurate definitions for the purposes of regulation led to conflicts related to the appropriateness of the BSER requirements to the full scope of facilities captured by the regulations. For example, the REC technology is utilized by hydraulically fractured wells where water can be separated from gas but the definitions captured nitrogen fractured wells that cannot use that technology. Not surprisingly, the regulations were challenged.

Subpart OOOO and Subpart W demonstrated EPA's limited understanding of the nature of oil and natural gas production facility emissions patterns. For NSPS development, failure to have a sound scope of knowledge on emissions and technologies creates a significant regulatory challenge. NSPS requires EPA to use "the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated". It creates four components that must be assessed and balanced – cost, nonair quality health and environmental impact, energy requirements and adequate demonstration. However, EPA never developed robust information on the emissions from oil and natural gas production facilities, never developed robust information on technologies to manage emissions, and never developed robust information on the four factors needed to determine BSER. Instead, EPA relied on is Gas STAR experience and whatever literature was available to it.

In 2013, an analysis developed by the University of Texas generated a new understanding of the emissions dynamics of oil and natural gas production facilities. Most methane emissions studies involve acquiring data from methane plumes using offsite monitoring. Inherently, this approach cannot distinguish between fugitive emissions and permitted emissions from vents and other operations. The University of Texas study included onsite emissions monitoring. One of its most significant findings was that the emissions profile from production operations included a substantial "fat tail" component. That is, while most of the equipment was characterized by low emissions, a small segment would have higher releases due to some type of failure. It raised the challenge of developing fugitive emissions management programs that target correcting this small segment cost effectively. Several state regulatory programs began to develop fugitive emissions programs.

By the beginning of 2014, the political, technical, regulatory framework was characterized by the following components. The Obama Administration was pursuing a more limited regulatory agenda in the context of managing emissions from the expanding development of natural gas. Technically, the emerging understanding of oil and natural gas production emissions was identifying that completion emissions were well managed by REC technology for hydraulically fractured wells, that operating emissions were generally low but with some "fat tails" that needed to be managed, and that the extent of this understanding was based on a limited amount of information and more was needed. Regulatorily, the primary federal regulations were embodied in the Subpart OOOO NSPS. And, states were beginning to assess methods to address operating emissions.

All of this was about to change.

The Obama Administration Prioritizes Climate Action

In June 2013, the Obama Administration announced its intent to develop a Climate Action Plan to address greenhouse gas (GHG) emissions. Among the target emissions was methane. Methane emissions account for roughly 9 percent of America's GHG emissions. Roughly, one-third of methane emissions come from oil and natural gas systems with roughly one-third of those from oil and natural gas production operations. Consequently, the share of America's GHG emissions from methane releases from oil and natural gas production is between one and two percent. Technically, methane and VOC are emitted simultaneously from oil and natural gas production operations and, therefore, controlling VOC – as Subpart OOOO had done – also controls methane. Significantly, oil and natural gas production emissions were declining.

The issue of managing methane emissions from oil and natural gas production facilities would become a pivotal one for the remainder of the Obama Administration. It was primarily a political issue played out in the regulatory arena. Methane has a higher GHG potential than carbon dioxide although it has a shorter lifetime. Environmentalists began a strategy to attack methane emissions using the climate agenda to address their renewable energy agenda that had been undermined by the shale gas revolution. Part of this agenda was challenging emissions estimates of methane; part of it was pressing the Obama Administration for regulation.

Taking the regulatory agenda first, as the Obama Administration began its second term, its interest in the economic benefits of American natural gas production diminished as the economy strengthened and natural gas supply was strong thereby assuring lower energy prices. As early as 2012, environmentalists had begun petitioning EPA for direct regulation of methane from oil and natural gas production. As the Obama Administration swung from building a strong American energy base to a new international climate role, its interest in aggressively federalizing oil and natural gas production regulation returned. Throughout 2014, environmentalists and industry were actively advocating regarding the need for additional regulation and its pathway.

At the heart of these deliberations was the argument over VOC versus methane regulation under the CAA. VOC is a criteria pollutant under the CAA. This means that the Act sets the regulatory options for both new and existing facilities. New and modified sources are regulated through NSPS, like Subpart OOOO. Existing VOC sources are regulated under the programs related to attainment of National Ambient Air Quality Standards (NAAQS) – in the case of VOC, the NAAQS for ozone. The CAA requires states with areas failing to attain a NAAQS to develop State Implementation Plans (SIPs) to reduce emissions. Ozone is particularly complex and Part D of the CAA sets out detailed requirements for areas to meet or to attempt to meet the ozone NAAQS.

Concurrent with the deliberations regarding its Climate Action Plan, the Obama Administration was considering revision of the ozone NAAQS. At issue was whether to lower the NAAQS and, if so, to what level. Lower levels of the ozone NAAQS would make more of the country nonattainment thereby requiring revised SIPs and bringing areas with existing oil and natural gas production under new regulation.

Methane is not a CAA criteria pollutant. However, EPA can develop NSPS for non-criteria pollutants – as it was doing for carbon dioxide. Environmentalists aggressively insisted on the Obama Administration regulating methane because of its desire to shut down existing oil and natural gas production operations. If EPA promulgates a NSPS for a non-criteria pollutant, the CAA creates a pathway to nationwide existing source regulations for those facilities (Section 111(d)). Consequently, if EPA regulated methane rather than VOC, existing sources could be subject to regulation on a national basis rather than an ozone nonattainment area basis.

Existing source oil and natural gas production regulation is particularly threatened because of the large number of low production oil and natural gas wells – marginal wells. Approximately 80 percent of American oil wells and two-thirds of American natural gas wells are marginal wells. The average marginal oil well produces about 2.2 barrels per day and the average marginal natural gas well produces about 22 mcf per day. Yet, collectively, these wells produce 10 to 20 percent of U.S. oil and 12 to 13 percent of U.S. natural gas. These wells are overwhelming small business operations and are the most economically vulnerable in the current price environment. Consequently, imposing costly regulations on these small sources will result in their shut down.

In January 2015, the Obama Administration announced the scope of its Climate Action Plan for methane emissions. At its heart was a new goal to cut methane emissions from the oil and gas sector by 40 – 45 percent from 2012 levels by 2025. For the oil and natural gas production industry, the announcement identified several key initiatives. First, EPA indicated that it would "…issue a proposed rule in the summer of 2015 and a final rule will follow in 2016." It would "…consider a range of common-sense approaches that can reduce emissions from the sources discussed in the agency's Oil and Gas White Papers, including oil well completions, pneumatic pumps, and leaks from well sites, gathering and boosting stations, and compressor stations." Second, EPA would "…develop new guidelines to assist states in reducing ozone-forming pollutants from existing oil and gas systems in areas that do not meet the ozone health standard and in states in the Ozone Transport Region." Third, EPA would "… explore potential regulatory opportunities for applying remote sensing technologies and other innovations in measurement and monitoring technology to further improve the identification and quantification of emissions and improve the overall accuracy and transparency of reported data cost-effectively." Fourth, BLM would "…update decades-old standards to reduce wasteful venting, flaring, and leaks of natural gas, which is primarily methane, from oil and gas wells."

These initiatives theoretically hinged on the need to meet a specific 40-45 percent reduction target. For the oil and natural gas production segment of the industry, the Gas STAR program and the 2012 Subpart OOOO regulations were producing the targeted reduction without additional regulation. Data showed that – throughout the extensive expansion of American natural gas production resulting from shale gas development – emissions were falling. Ignoring the clear history of falling emissions with increased production, the Obama Administration concluded that expanded production would increase future emissions. While such an argument might have bearing in other industry segments, for oil and natural gas production the inherent decline that occurs in all wells means that maintaining and growing production requires new wells to replace old ones. Therefore, in the time window of 2012 to 2025, the pool of American production wells would be dominated by wells drilled with the new technologies. Consequently, justifying the expanded regulatory agenda required the Obama Administration to change emissions projections.

EPA Proposes Methane Regulations

In late 2015, EPA proposed its package of regulations. For oil and natural gas production facilities it included an expansion of NSPS – Subpart OOOOa, a new Control Techniques Guidelines (CTG) for existing sources in ozone nonattainment areas, and a revised voluntary reduction program replacing Gas STAR. Importantly, the NSPS targeted methane reductions and included a REC program for associated gas from fractured crude oil wells, mandates for pneumatic pumps, and an extensive fugitive emissions program.

The proposal created several contentious issues. First, as noted above, was whether the additional regulations were justified. Second was the selection of methane as the targeted emission because of the potential for the creation of nationwide existing source regulations. Third was the specific requirements of the fugitive emissions program. The fourth related to the CTG proposal. And, fifth was the nature of the voluntary program named The Methane Challenge by EPA.

EPA's decision to choose methane regulation was a linchpin to obtain support from the Keep It in the Ground environmentalists. They primarily focused on developing regulations on existing sources and the methane choice opened that pathway through Section 111(d) of the CAA.

The fugitive emissions issue largely revolved around three factors. First, several states had implemented or were developing fugitive programs, but none of them paralleled the EPA proposal. Since BSER should be based on adequately demonstrated technologies, this inconsistency raised a fundamental question of whether the EPA proposal was BSER. Second, a key component of the EPA proposal was its Leak Detection and Repair (LDAR) requirements. EPA's LDAR program relied on highly costly optical gas imaging (OGI) that raised significant cost effectiveness issues depending on the size of the operation. Third, the proposed rule exempted low producing wells from these requirements, but the process was uncertain. And, its inclusion was strongly opposed by the environmental lobby.

The CTG proposal raised two significant questions. First, if EPA was regulating methane in the NSPS and thereby opening the path to nationwide existing source regulation, a VOC CTG created a second existing source federally generated requirement. EPA suggested that the CTG would be the existing source program, but this view was not endorsed elsewhere in the Obama Administration. And, environmentalists were insisting that once EPA acted on a methane NSPS, it must then regulate existing sources under Section 111(d) – a position that EPA disputed. Second, the CTG essentially based its regulations on the NSPS Subpart OOOO and proposed Subpart OOOOa technology. But, even if the NSPS regulations could be viewed as BSER, CTG are based on Reasonably Available Control Technology (RACT). BSER is not RACT and the technology test is particularly different in assessing its impact on old and small facilities.

While EPA was touting its Methane Challenge as comparable to Gas STAR, industry viewed it as very different, particularly in the context of a massive regulatory initiative. While industry sought to develop a voluntary program that it could embrace as it had Gas STAR, the Methane Challenge did not offer incentives encouraging participation. For example, participation in the Methane Challenge did not prevent EPA from imposing additional regulation that would overlay the voluntary technology placing industry in a position of essentially being regulated twice. Without such incentives, industry had little interest in embracing the Methane Challenge.

Responding to the proposed requirements, industry challenged the Obama Administration justification that these additional regulations were needed to counter increasing methane emissions. Part of the challenge related to the turnover in wells to those with the Subpart OOOO technology during the 2012 to 2025 period. Part of the challenge focused on the small contribution of oil and natural gas production to total GHG emissions. In late 2015-early 2016, EPA countered by changing its calculation of oil and natural gas production emissions estimates in the GHGI. To put this revision in context, a brief discussion of the GHGI is necessary. Not all oil and natural gas production facilities report under Subpart W. EPA set a threshold to limit the burden on small producers and to reflect that smaller wells emit less. Consequently, when it added oil and natural gas production to the GHGI, EPA announced that by obtaining data from about 30 percent of producers, it would capture 85 percent of the GHG emissions. This was logical because the 70 percent of producers not reporting would be the small production wells. Suddenly, in 2015, EPA announced its intent to change the estimating process because of information it had on pneumatic controllers showing higher than previously estimated emissions. However, rather than follow its prior approach, EPA announced that it would revise emissions estimates based on scaling up the reported emissions based on producers. It thereby attributed 70 percent of the emissions to the small wells. This outrageous redistribution of emissions clearly created a basis to imply that there was a need to impose greater regulations. Additionally, EPA gratuitously added emissions from gathering and boosting operations to the production sector.

EPA Regulations Finalized – Litigation Follows

In March 2016, EPA announced its NSPC regulatory package which became effective in June 2016. The package was largely unchanged from the proposal with one significant exception. EPA had deleted the exclusion for low production wells. Environmentalists characterized this deletion as the single, most important provision in the package. They then demanded that EPA act under Section 111(d) on existing sources. EPA declined to act immediately but announced that it would be initiating an Information Collection Request (ICR) to gather information on existing oil and natural gas production.

EPA's action to remove the low production well exclusion is instructive in understanding the issues associated with EPA's technical support for its actions. As described above, EPA has a responsibility under the CAA to determine BSER for NSPS regulations. From the time EPA entered into the consent decree that led to Subpart OOOO, EPA's technical information development consisted largely of the creation of five white papers – papers that were an amalgamation of studies undertaken by others. EPA sought comments and created some working groups. But, EPA did not develop its own data. This is a fundamental and unsettled issue regarding what responsibility EPA bears to assure that its regulatory judgments are sound.

Regarding the decision to eliminate its proposed NSPS low production well exclusion, EPA relied on a study developed by the Environmental Defense Fund (EDF) that was submitted to the record. Although EPA had proposed the exclusion and industry had supported it, EPA then removed the exclusion arguing that counter information had been submitted – the EDF study – and it had not been refuted. Yet, EPA did nothing to assess the validity of the EDF study.

The purpose of the EDF study was to contort available methane sampling data to create the illusion that low producing wells were "super-emitters". All of the underlying studies generated their data by driving vehicles with samplers downwind of production sites, hunting for methane plumes. None of them used samples taken on the production site. This creates two issues. First, it measures everything emitted at the site – fugitive emissions and permitted vents. Second, the data are collected over minutes – maybe over an hour – but not over a day. The data in the study are presented as if they were daily emissions but the studies merely scale up hourly estimates. Consequently, an emission that might occur for several hours, but not the full day, would be overstated. The study shows emissions as a percentage of production rather than actual emissions. Thus, one mcf emitted out of ten mcf produced is 10 percent, but 50 mcf emitted out of 1000 mcf produced is 5 percent. As a result, it skews the perception of the data to imply that low producing wells are large emitters when they are not. The study's production volumes are really sales volumes, not the amount extracted from the wellhead. Consequently, a "proportional loss rate" of 50 percent would be the calculated loss divided by the volume sold. If the percentage of loss were calculated based on extracted volumes, the 50 percent "proportional loss rate" would drop to 33 percent because the loss would be added to the sales volume to obtain the extracted volume. It only shows data from the 70th percentile of information. This excludes all of the virtually zero emissions that dominate the data. It uses a logarithmic scale to present the data. One of the reasons to use logarithmic scales is to flatten curves to make them look more like straight lines.

These observations can be made without conducting an intense investigation of the study. The study is obviously intended to contort data to create a specific result. Yet, with all the investigative power at EPA, with all of the research work EPA has conducted, EPA took this contrived study at face value to make its determination to remove the low producing well exclusion in the Subpart OOOOa regulations.

In October 2016, EPA finalized the CTG for existing sources which also included a fugitive emissions program but EPA deferred action on how to treat low production wells. This deferral has less meaning than NSPS action because CTG are a framework for states to develop their own regulations and are not specific mandates. However, if a state fails to adopt a CTG based regulation, it must adopt other regulations to achieve the calculated reductions in emissions that the CTG would have provided.

In November 2016, EPA finalized its ICR and began transmitting them to oil and natural gas producers. The ICR required substantial information that would take months to complete. However, the Obama Administration wanted to complete the ICR prior to its end and thereby required completion of the ICR prior to January 20, 2017. EPA was unable to distribute the ICR consistent with this schedule and the ICR remained active when the Trump Administration began.

Multiple parties responded to the Subpart OOOOa regulations seeking judicial repeal and administrative reconsideration in July-August 2016. The Independent Petroleum Association of America (IPAA) and 18 other trade associations, the American Petroleum Institute, the Western Energy Alliance, the Texas Oil and Gas Association, the Interstate Natural Gas Association of America, North Dakota, Texas, West Virginia and 13 other states filed to challenge the Subpart OOOOa regulations in the D.C. Circuit Court; the litigation was consolidated as *North Dakota v. EPA*. Additionally, the IPAA group and others filed petitions for reconsideration on several issues with EPA.

The Trump Administration Acts to Revisit the Regulations – Litigation Follows

With the advent of the Trump Administration, the dynamics of these regulations have changed, but the future is by no means certain.

In March 2017, EPA terminated the ICR following a request by eleven states.

In April 2017, EPA acted to put the *North Dakota v EPA* case in abeyance until it could reconsider the Subpart OOOOa regulations. In May 2017, the D.C. Circuit Court agreed.

In late May 2017, EPA announced a 90-day stay of several components of the Subpart OOOOa regulations including the fugitive emissions program that was scheduled to begin in June. A coalition of environmental groups filed action to block the stay. In mid-June, EPA proposed a two-year suspension of these components of Subpart OOOOa. On July 3, 2017, the DC Circuit Court agreed with the environmental groups and vacated the 90-day stay while mandating immediate application of the regulations. On July 7, 2017, EPA appealed the mandate and sought additional time. The Court sought responses to the EPA appeal during the week of July 11 and delayed the mandate for an additional 14 days to allow EPA to decide its next course of action. Meanwhile, the two-year suspension is undergoing its comment period under the Administrative Procedure Act. This issue of reconsideration will continue to be a ripe forum for litigation for the foreseeable future whether it is related to initiating reconsideration or the regulations that might ultimately be proposed.

Meanwhile, a number of governors have notified EPA that they intend to sue EPA for failing to initiate existing source methane regulations under Section 111(d).

Separately, the CTG for existing sources is becoming an issue in state planning. Although EPA promulgated a revision to the ozone NAAQS in 2015, the revision is being litigated. The Trump Administration has indicated that it may reconsider the revised NAAQS. As a predicate to that action, EPA announced that it will delay requirements for states to submit SIPs; litigation has been initiated to challenge this delay. However, due to its action to revise the ozone NAAQS in 2015, EPA failed to have states submit SIPs to address the 2008 revisions to the ozone NAAQS. Subsequent litigation resulted in EPA being ordered to pursue those SIPs. States are now considering regulations and, since the existing source CTG was finalized in October 2016, it is now a CTG that must be included in state planning. Consequently, this CTG – based on NSPS regulations that are being reconsidered – is now in play for small business wells.

Additionally, in January 2016, BLM proposed its methane regulations that include specific requirements for existing sources on BLM managed resources. These regulations largely track the CTG requirements. The regulations were finalized in November 2015 and were challenged in the Wyoming District Court. Congress attempted to rescind the regulations using the Congressional Review Act (CRA) but it failed. BLM moved to pause the regulations while it reconsiders them. New Mexico and California are acting to challenge the BLM action.

A Future of Regulatory Litigation and Chaos

Clearly, the confrontations over federal methane regulation of oil and natural gas production will continue and escalate. These regulations were driven to final action during the waning days of the Obama Administration. They are built on a characterization of emissions that is false. They fly in the face of a history of methane reductions in the oil and natural gas production segment of the industry and continued expectations of declining emissions in future years. They have become the hyperbolic political fodder for the Keep It in the Ground environmental movement that twists information to pursue its specific agenda.

However, they will also be a part of a larger fabric of litigation that is going to test the nature of America's federal environmental laws and its administrative procedural process. Substantive issues will be subordinated to procedural ones. The challenges of unwinding the current regulations from the judicial process, developing revisions and moving those proposals to completion will test the remaining years of the Trump Administration. EPA's last Obama Administrator once said about regulation of oil and natural gas production:

> EPA's learning this industry right now because it is not an industry we regulate. We've just gotten into regulation of this so there's a lot of hundreds of thousands of small sources and EPA does not generally have a relationship with this industry as we do other sectors that we've regulated for frankly decades. But we are learning.

Unfortunately, EPA began regulating before it learned. Unlike most industries, oil and natural gas production begins to decline soon after it starts. The industry is comprised of large and small businesses with most low producing wells operated by small businesses. Regulations that might be cost effective when a well is new will not be after it declines and certainly when it is a low producing well. Many of the technologies that these regulations require and use are cost effective for new, large, hydraulically fractured oil and natural gas wells, but others need to revisited. Then, at issue will be whether regulations are needed for America's marginal wells and, if so, whether regulations can be created to manage marginal well emissions rather than force them to be shutdown.

While the federal framework on methane regulations – and other Obama Administration initiated regulations and policies – is wrapped up in aggressive changes by the Trump Administration, Keep It in the Ground environmentalists are not only reacting in the federal court and regulatory agency arena but turning to other venues as well. State regulations will be one target. Using the same arguments – and same specious data – the environmental lobby will be pursuing its agenda by trying to get state legislators and regulators to adopt regulations comparable or more excessive than those promulgated by the Obama Administration. It will continue to litigate and petition for action on the federal level to try to drive or, at least, constrain the federal agenda. And, it will likely seek venues for citizen suits against individual companies.

On balance, the next several years will be challenging for all parties as the nature of the regulatory process – federal and state – and the dynamics of litigation will be tested – more on procedure than substance.

Message

From: Stephen Fotis [scf@vnf.com]
Sent: 11/1/2017 1:12:01 AM
To: Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]; Schwab, Justin [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=eed0f609c0944cc2bbdb05df3a10aadb-Schwab, Jus]
CC: Marnie Funk (Marnie.Funk@shell.com) [Marnie.Funk@shell.com]
Subject: Shell Meeting on OOOOa Reconsideration Rulemaking

Mandy and Justin – Many thanks for making time this afternoon to meet with Marnie and me regarding the OOOOa NSPS reconsideration rulemaking. On behalf of Shell, we very much appreciate all of your efforts to review and reform the current OOOOa regulatory regime, and look forward working with you on the upcoming rulemaking. We will be following up with Peter Tsirigotis and his staff at RTP as you've suggested. In the interim, please let us know if there is way that Shell can be of assistance to you.
Best regards,
Stephen

Stephen Fotis
Partner
Van Ness Feldman LLP
scf@vnf.com
Ex. 6

Message

From: Peter Robertson [peterrobertson@pebblepartnership.com]
Sent: 9/18/2017 11:46:20 AM
To: Veney, Carla [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=c354b58bf2b1464d8afac7bbd2a7a88c-CVeney]
CC: Schwab, Justin [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=eed0f609c0944cc2bbdb05df3a10aadb-Schwab, Jus]
Subject: Re: checking in

Try my office number first. Ex. 6 If for any reason I don't answer that, my cell is Ex. 6

Peter

Peter D. Robertson
Ex. 6
Sent from my iPhone

From: Veney, Carla <Veney.Carla@epa.gov>
Sent: Monday, September 18, 2017 7:04:46 AM
To: Peter Robertson
Cc: Schwab, Justin
Subject: RE: checking in

Good Morning, can you provide a telephone number for us to call you? Thank you.

From: Peter Robertson [mailto:peterrobertson@pebblepartnership.com]
Sent: Friday, September 15, 2017 4:03 PM
To: Veney, Carla <Veney.Carla@epa.gov>
Cc: Schwab, Justin <Schwab.Justin@epa.gov>
Subject: Re: checking in

yes, thanks. That time would work well.

Peter

From: Veney, Carla <Veney.Carla@epa.gov>
Sent: Friday, September 15, 2017 3:56:35 PM
To: Peter Robertson
Cc: Schwab, Justin
Subject: FW: checking in

Good Afternoon, I would like to assist in scheduling the call on Monday morning with Kevin Minoli and Justin. Would you be available at 11:00?

From: Schwab, Justin
Sent: Thursday, September 14, 2017 5:01 PM
To: Patrick, Monique <Patrick.Monique@epa.gov>
Cc: Minoli, Kevin <Minoli.Kevin@epa.gov>; Fotouhi, David <Fotouhi.David@epa.gov>; Veney, Carla <Veney.Carla@epa.gov>
Subject: Re: checking in

Sounds good - thank you!

Sent from my iPhone

On Sep 14, 2017, at 4:52 PM, Patrick, Monique <Patrick.Monique@epa.gov> wrote:

Hi Justin

Since Kevin will be invited, I am cc'ing Carla to take the lead on scheduling this mtg. OK?

From: Schwab, Justin
Sent: Wednesday, September 13, 2017 8:10 PM
To: Patrick, Monique <Patrick.Monique@epa.gov>
Cc: Minoli, Kevin <Minoli.Kevin@epa.gov>; Fotouhi, David <Fotouhi.David@epa.gov>
Subject: Fwd: checking in

Dear Monique,

Please reach out to Peter Robertson (his email is in the thread below) to schedule a call with him for Kevin, David, and me.

Thank you!

Sent from my iPhone

Begin forwarded message:

From: Peter Robertson <peterrobertson@pebblepartnership.com>
Date: September 13, 2017 at 4:55:59 PM EDT
To: "Schwab, Justin" <Schwab.Justin@epa.gov>
Subject: Re: checking in

She can coordinate directly with me, Justin.

Thanks.

PDR

From: Schwab, Justin <Schwab.Justin@epa.gov>
Sent: Tuesday, September 12, 2017 10:10:33 PM
To: Peter Robertson
Subject: Re: checking in

Peter,

Happy to. There are a few colleagues I should loop in who will help inform our conversation. I will ask my assistant to set up a time that works for everyone - can you please let me know whether there is someone I should have her coordinate with on timing or can she coordinate with you directly?

Best,

Justin

Sent from my iPhone

On Sep 12, 2017, at 2:48 PM, Peter Robertson
<peterrobertson@pebblepartnership.com> wrote:

> Justin,
>
> Do you have time for a quick call checking in on our previous discussions? I promise not to take more than a few minutes.
>
> I'm around all this week (and next, if that's better).
>
> Peter

Message

From: Peter Robertson [peterrobertson@pebblepartnership.com]
Sent: 7/6/2017 1:27:27 PM
To: Schwab, Justin [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=eed0f609c0944cc2bbdb05df3a10aadb-Schwab, Jus]
Subject: Re: Touching base

Will do!!

Peter D. Robertson
Ex. 6
Sent from my iPhone

From: Schwab, Justin <schwab.justin@epa.gov>
Sent: Thursday, July 6, 2017 9:05:15 AM
To: Peter Robertson
Subject: Re: Touching base

Thanks! Monday should work. Please ping me that morning and we'll set up a time to talk

Sent from my iPhone

On Jul 6, 2017, at 9:04 AM, Peter Robertson <peterrobertson@pebblepartnership.com> wrote:

> I will NEVER interrupt an EPA politics employee's vacation. They are so few and far between. Let's try to touch base on Monday or Tuesday, though I know you will slammed when you get back.
>
> Thanks. Enjoy!
>
> Peter
>
> Peter D. Robertson
> Ex. 6
> Sent from my iPhone
>
> ---
>
> **From:** Schwab, Justin <schwab.justin@epa.gov>
> **Sent:** Thursday, July 6, 2017 8:49:47 AM
> **To:** Peter Robertson
> **Subject:** Re: Touching base
>
> Peter,
>
> I am on vacation and reception is poor where I am, but I could attempt a call today. Alternatively I could refer you to someone in HQ. I will be back in the office Monday.
>
> Best,
>
> Justin
>
> Sent from my iPhone

On Jul 5, 2017, at 12:35 PM, Peter Robertson <peterrobertson@pebblepartnership.com> wrote:

Justin,

Hope you had a great 4th of July break, and that maybe you're enjoying a somewhat less frantic period while Congress is away.

I'm wondering whether you have time to touch base today or tomorrow, as an update to our previous call?

Thanks.

Peter

Message

From: Peter Robertson [peterrobertson@pebblepartnership.com]
Sent: 6/2/2017 5:22:40 PM
To: Schwab, Justin [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=eed0f609c0944cc2bbdb05df3a10aadb-Schwab, Jus]
Subject: Re: Call

Thanks, Justin. Call me on my office phone first -- Ex. 6 If for any reason I don't answer that phone, my cell is Ex. 6

Look forward to it.

Peter

From: Schwab, Justin <schwab.justin@epa.gov>
Sent: Friday, June 2, 2017 11:46:03 AM
To: Peter Robertson
Subject: Re: Call

That should work. I will call you at or as soon after 2 as I can

Sent from my iPhone

On Jun 2, 2017, at 11:08 AM, Peter Robertson <peterrobertson@pebblepartnership.com> wrote:

> Justin,
>
> Will 2:00 this afternoon work?
>
> Peter
>
> ---
>
> **From:** Peter Robertson
> **Sent:** Friday, June 2, 2017 7:48:08 AM
> **To:** Schwab, Justin
> **Subject:** Re: Call
>
> From now until 10:00; from 10:15 until noon; then from 2:00 on.
>
> Peter D. Robertson
> Ex. 6
> Sent from my iPhone
>
> ---
>
> **From:** Schwab, Justin <schwab.justin@epa.gov>
> **Sent:** Friday, June 2, 2017 7:01:52 AM
> **To:** Peter Robertson
> **Subject:** Re: Call
>
> Peter,

Sure. When are you available today?

Sent from my iPhone

On Jun 1, 2017, at 10:54 PM, Peter Robertson <peterrobertson@pebblepartnership.com> wrote:

> Justin,
>
> It's Peter Robertson at the Pebble Partnership. Thanks for your good work in getting us to settlement.
>
> Do you have just a moment tomorrow for a very quick question? I promise it's not more than a 5 minute call.
>
> Thanks.
>
> Peter
>
> Peter D. Robertson
> Ex. 6
> Sent from my iPhone

Message

From: Bond, Alex [ABond@eei.org]
Sent: 6/21/2017 2:40:15 PM
To: Schwab, Justin [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=eed0f609c0944cc2bbdb05df3a10aadb-Schwab, Jus]
CC: Fisher, Emily [EFisher@eei.org]; Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: RE: NSR

Great, thanks Justin!

From: Schwab, Justin [mailto:schwab.justin@epa.gov]
Sent: Wednesday, June 21, 2017 10:36 AM
To: Bond, Alex
Cc: Fisher, Emily; Gunasekara, Mandy
Subject: Re: NSR

I am CC'ing Mandy Gunasekara, the administrator's senior policy advisor on air issues. I am happy to participate in a meeting if I can be of help but defer to her on timing, agenda, etc.

Sent from my iPhone

On Jun 21, 2017, at 10:29 AM, Bond, Alex <ABond@eei.org> wrote:

> Thanks, Emily! Justin – happy to set up some time to talk. What does your schedule look like in the coming weeks?
>
> ---
>
> **From:** Fisher, Emily
> **Sent:** Wednesday, June 21, 2017 8:48 AM
> **To:** schwab.justin@epa.gov
> **Cc:** Bond, Alex
> **Subject:** NSR
>
> Justin,
>
> It was nice to meet you at the Monday meeting with the Administrator. We appreciate the opportunity to discuss issues that are important to electric companies. As I noted, we've been thinking about NSR and how to improve the process. I've copied Alex Bond on this e-mail. He's leading our internal and member discussions on this issue. If it works for you, Alex will reach out to set up a meeting to discuss some of our thoughts.
>
> Best,
>
> Emily Fisher

Emily Sanford Fisher
Vice President, Law
Corporate Secretary
701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
Ex. 6
www.eei.org

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<image001.png>

Message

From: Fisher, Emily [EFisher@eei.org]
Sent: 6/21/2017 12:47:40 PM
To: Schwab, Justin [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=eed0f609c0944cc2bbdb05df3a10aadb-Schwab, Jus]
CC: Bond, Alex [ABond@eei.org]
Subject: NSR

Flag: Flag for follow up

Justin,

It was nice to meet you at the Monday meeting with the Administrator. We appreciate the opportunity to discuss issues that are important to electric companies. As I noted, we've been thinking about NSR and how to improve the process. I've copied Alex Bond on this e-mail. He's leading our internal and member discussions on this issue. If it works for you, Alex will reach out to set up a meeting to discuss some of our thoughts.

Best,

Emily Fisher

Emily Sanford Fisher
Vice President, Law
Corporate Secretary
701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
Ex. 6
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Message

From: Schwab, Justin [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=EED0F609C0944CC2BBDB05DF3A10AADB-SCHWAB, JUS]
Sent: 12/4/2017 11:45:59 PM
To: Peter Robertson [peterrobertson@pebblepartnership.com]
CC: Fotouhi, David [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=febaf0d56aab43f8a9174b18218c1182-Fotouhi, Da]
Subject: RE: status check

We'll call you at 4.

From: Peter Robertson [mailto:peterrobertson@pebblepartnership.com]
Sent: Monday, December 4, 2017 6:44 PM
To: Schwab, Justin <Schwab.Justin@epa.gov>
Cc: Fotouhi, David <Fotouhi.David@epa.gov>
Subject: Re: status check

that works like a charm. thanks so much for getting back to me.

I'm happy to call you, or you can call me in my office Ex. 6. Let me know your preferences.

Best,

Peter

From: Schwab, Justin <Schwab.Justin@epa.gov>
Sent: Monday, December 4, 2017 6:41:54 PM
To: Peter Robertson
Cc: Fotouhi, David
Subject: RE: status check

Peter,

Sorry we didn't connect today. David (cc'd here) and I could do 4 PM on Wednesday if that works for you.

From: Peter Robertson [mailto:peterrobertson@pebblepartnership.com]
Sent: Monday, December 4, 2017 10:49 AM
To: Schwab, Justin <Schwab.Justin@epa.gov>
Subject: Re: status check

Justin,

Would still like to try to connect with you when you have a moment. I'm traveling today and tomorrow, but available by telephone nearly anytime today. Then back in the office on Wednesday.

Are you available for a quick chat?

Thanks.

Peter

From: Peter Robertson
Sent: Tuesday, November 28, 2017 9:05:23 AM
To: Schwab, Justin
Subject: Re: status check

Hi Justin.

Just following up on this email from earlier in the month. Do you have time to talk today?

Hope all is well.

Peter

Peter D. Robertson
Ex. 6
Sent from my iPhone

From: Peter Robertson
Sent: Tuesday, November 14, 2017 12:43:39 PM
To: Schwab, Justin
Subject: status check

Justin,

I hope all is well with you. I'm pleased to see that EPA is getting a bigger component of political appointees in, finally.

I'm wondering whether you can shed any light on the likelihood that the Agency's work on withdrawing the proposed determination will be done before the end of the year. Would appreciate hearing your thoughts as to that. I know you have said before that the Administrator wants this done quickly, and we obviously appreciate that. I'm not looking for a specific date, but rather can you estimate that it will be done before the end of the year or is it more likely to be done in the first quarter of 2018?

I hope it goes without saying that I'm not looking for any information about how the decision will come out -- to withdraw or not -- only information on the timing.

Thanks for anything you can share.

Best,

Peter

Message

From: Schwab, Justin [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=EED0F609C0944CC2BBDB05DF3A10AADB-SCHWAB, JUS]
Sent: 10/4/2017 1:08:45 PM
To: Lee Fuller [lfuller@ipaa.org]
CC: James D. Elliott (jelliott@spilmanlaw.com) [jelliott@spilmanlaw.com]; Kern, Gretchen (Gretchen.Kern@pxd.com) [Gretchen.Kern@pxd.com]; Schaaff, Lesley [lschaaff@hess.com]; Susan Ginsberg [sginsberg@ipaa.org]; Samantha McDonald [SMcDonald@ipaa.org]
Subject: RE: IPAA Meeting Follow Up

Thank you!

From: Lee Fuller [mailto:lfuller@ipaa.org]
Sent: Tuesday, October 3, 2017 5:05 PM
To: Schwab, Justin <Schwab.Justin@epa.gov>
Cc: James D. Elliott (jelliott@spilmanlaw.com) <jelliott@spilmanlaw.com>; Kern, Gretchen (Gretchen.Kern@pxd.com) <Gretchen.Kern@pxd.com>; Schaaff, Lesley <lschaaff@hess.com>; Susan Ginsberg <sginsberg@ipaa.org>; Samantha McDonald <SMcDonald@ipaa.org>
Subject: IPAA Meeting Follow Up

Justin,

We appreciated meeting with you and Mandy yesterday regarding air emissions management of oil and natural gas production operations. I have attached several documents that expand on the nature of the issues that we discussed. There will be some repetition because the issues have been addressed several times.

They include:

1. IPAA comments to EPA on Evaluating Existing Regulations
2. IPAA-AXPC Comments on the Subpart OOOOa, CTG and Source Determination proposals in 2015
3. IPAA-AXPC-Coalition Petition for Reconsideration of Subpart OOOOa – includes the low production well issue among others
4. An assessment of the data manipulation in the study that EPA used to eliminate the low production well exclusion from Subpart OOOOa
5. A publication that I prepared for a meeting on environmental issues in the oil patch that uses the development of the air emissions regulations as its focus beginning with Subpart OOOO.

Thanks again for the opportunity to meet on these issues.

Lee Fuller

Message

From: Schwab, Justin [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=EED0F609C0944CC2BBDB05DF3A10AADB-SCHWAB, JUS]
Sent: 7/10/2017 9:33:42 PM
To: Peter Robertson [peterrobertson@pebblepartnership.com]
CC: Thomas M. Barba [tbarba@steptoe.com]
Subject: Re: Call

Will call imminently

Sent from my iPhone

On Jul 10, 2017, at 12:32 PM, Peter Robertson <peterrobertson@pebblepartnership.com> wrote:

> Sounds great, Justin. Speak with you then.
>
> PDR
>
> ---
>
> **From:** Schwab, Justin <schwab.justin@epa.gov>
> **Sent:** Monday, July 10, 2017 12:12:50 PM
> **To:** Peter Robertson
> **Cc:** Thomas M. Barba
> **Subject:** Re: Call
>
> 5:30 should work - if I cannot make it then I will let you know as soon as I am able and will make myself available as close to 5:30 as I can
>
> Sent from my iPhone
>
> On Jul 10, 2017, at 11:48 AM, Peter Robertson <peterrobertson@pebblepartnership.com> wrote:
>
>> Justin,
>>
>> I meant to hit reply all, and failed to do so. Let me and Tom Barba know whether 5:00 or 5:30 or some other time works best for you.
>>
>> Tom Barba -- in the meantime, can you send around a call in number so that Justin can reach us from wherever he may be?
>>
>> Thanks.

Peter

From: Peter Robertson
Sent: Monday, July 10, 2017 9:38 AM
To: Barba, Thomas
Subject: Re: Call

Works for me as well.

Tell us what works for you, Justin. 5:00? 5:30 to be safe?

Peter D. Robertson
Ex. 6
Sent from my iPhone

From: Barba, Thomas <TBarba@steptoe.com>
Sent: Monday, July 10, 2017 9:35:18 AM
To: Peter Robertson
Subject: Fwd: Call

I'm free then.

Begin forwarded message:

From: "Schwab, Justin" <schwab.justin@epa.gov>
Date: July 10, 2017 at 9:32:39 AM EDT
To: Peter Robertson <peterrobertson@pebblepartnership.com>
Cc: Thomas Barba <tbarba@steptoe.com>
Subject: Re: Call

Peter,

I am booked solid until at least 5 but could do a call this evening

Sent from my iPhone

On Jul 10, 2017, at 8:59 AM, Peter Robertson <peterrobertson@pebblepartnership.com> wrote:

Justin,

Good morning and welcome back. Is there a good time today for us to have a quick call? I look forward to hearing from you.

Peter

Peter D. Robertson
Ex. 6
Sent from my iPhone

Message

From: Schwab, Justin [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=EED0F609C0944CC2BBDB05DF3A10AADB-SCHWAB, JUS]
Sent: 6/21/2017 2:35:38 PM
To: Bond, Alex [ABond@eei.org]
CC: Fisher, Emily [EFisher@eei.org]; Gunasekara, Mandy [/o=ExchangeLabs/ou=Exchange Administrative Group (FYDIBOHF23SPDLT)/cn=Recipients/cn=53d1a3caa8bb4ebab8a2d28ca59b6f45-Gunasekara,]
Subject: Re: NSR

I am CC'ing Mandy Gunasekara, the administrator's senior policy advisor on air issues. I am happy to participate in a meeting if I can be of help but defer to her on timing, agenda, etc.

Sent from my iPhone

On Jun 21, 2017, at 10:29 AM, Bond, Alex <ABond@eei.org> wrote:

> Thanks, Emily! Justin – happy to set up some time to talk. What does your schedule look like in the coming weeks?
>
> ---
>
> **From:** Fisher, Emily
> **Sent:** Wednesday, June 21, 2017 8:48 AM
> **To:** schwab.justin@epa.gov
> **Cc:** Bond, Alex
> **Subject:** NSR
>
> Justin,
>
> It was nice to meet you at the Monday meeting with the Administrator. We appreciate the opportunity to discuss issues that are important to electric companies. As I noted, we've been thinking about NSR and how to improve the process. I've copied Alex Bond on this e-mail. He's leading our internal and member discussions on this issue. If it works for you, Alex will reach out to set up a meeting to discuss some of our thoughts.
>
> Best,
>
> Emily Fisher
>
> Emily Sanford Fisher
> Vice President, Law
> Corporate Secretary
> 701 Pennsylvania Avenue, N.W.
> Washington, D.C. 20004-2696
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