James D. Elliott
717.791.2012
jelliott@spilmanlaw.com

August 9, 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 Fed. Reg. 27,645 (June 16, 2017)

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

Dear Administrator Pruitt:

The following comments are submitted on the above-referenced proposed rule ("Proposed Rule") 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") 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, 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 explain to the EPA that their "one-size-fits-all" approach to regulating this industry is inappropriate. The Proposed Rule 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 Proposed Rule.[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 Proposed Rule 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.

A. The EPA's Proposed Two-Year Stay is Reasonable and Authorized Under the Law.

On July 27, 2017, the American Petroleum Institute ("API") submitted comments on the Proposed Rule that focused on the legal authorities available to the EPA in order to take the proposed actions set forth in the Proposed Rule (EPA-HQ-OAR-2010-0505-10577). API's comments outline three principal means to effecting the two-year "stay": 1) extend the relevant compliance deadlines in Subpart OOOOa for a period of two years while the EPA evaluates the various issues raised in Petitions for Reconsideration pursuant to its authority in Section 111 of the Clean Air Act ("CAA"); 2) issue a stay under Section 705 of the Administrative Procedure Act, which authorizes a stay pending judicial review when justice is required; or 3) issue a stay pursuant to the EPA's general rulemaking authority under CAA Section 301(a). The Independent Producers incorporate by reference and endorse API's July 27, 2017 comments focusing on the EPA's legal authorities.

Regardless of the legal authority for the EPA's Proposed Rule, whether characterized as a "stay" or extension of compliance deadlines, fairness and justice for the Independent Producers' individual members that are disproportionally impacted by Subpart OOOOa and 40 C.F.R. Part 60, Subpart OOOO ("Subpart OOOO") justify the EPA's Proposed Rule. From the beginning of these related rulemakings in 2011, IPAA and many of the individual associations and their individual members have tried to explain the physical differences, economic differences, and differences in environmental impacts from the considerably smaller vertical and conventional operations that were swept into Subpart OOOOa and Subpart OOOO. Representatives from the Independent Producers traveled to the EPA's office in Research Triangle Park, NC, and met with representatives from the EPA prior to finalization of both Subpart OOOO and Subpart OOOOa. During these meetings there was considerable focus on the few possible exemptions that would provide some relief from reduced emission completions and fugitive emissions reduction measures for "low pressure wells" and "low production wells." The existence of the provisions related to low pressure wells and low production wells had the potential to considerably reduce the regulatory burden on certain vertical wells and conventional operations, many of which constitute small entities or small businesses under the Small Business Regulatory Enforcement Fairness Act.

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

Representatives of the Independent Producers participated in the Small Business Advocacy Review Panel associated with Subpart OOOOa in 2015. The comments of IPAA and other individual associations filed during the rulemaking process for Subpart OOOO and Subpart OOOOa had little impact on the final versions of the rules.[2] The EPA has legal authority to finalize the Proposed Rule and utilize the two-year period to evaluate the factual issues not addressed by the previous Administration.

B. The Impact of Proposed Rule for Certain Individual Members of the Independent Producers is Critical: Stay in Business or Close Up Shop.

As explained in the meetings with the previous Administration and in the Independent Producers' attached comments on Subpart OOOO and Subpart OOOOa, the leak detection and repair ("LDAR") requirements as applied to low production wells is likely to make many of these wells uneconomical for the Independent Producers.[3] Certain members of the Independent Producers entire business consists of low production wells. In many cases, an operator will forgo "modifying" an existing low production well because of the costs of the LDAR requirements. The EPA has failed to quantify in any meaningful way the emissions associated with leaks from low production wells. 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 can 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. To many, the impact of the Proposed Rule means that they can continue to operate while the EPA fairly and appropriately addresses the issue. The EPA reversed course without adequate explanation and even the United States Court of Appeals for District of Columbia Circuit ("DC Circuit Court") failed to meaningfully address the EPA's internally inconsistent logic between emissions associated with modifications and low production wells. The DC Circuit Court dismissed the issue by saying that the EPA failed to cite the inconsistent logic as a reason for granting reconsideration in its original grant of reconsideration of the removal of the low production exemption in the April 18, 2017

---

[2] Copies of the comments IPAA took the lead in preparing and filed during the various Subpart OOOO and Subpart OOOOa rulemakings are attached to this comment letter for inclusion in this administrative record. Not every member of the Independent Producers participated in every set of comments.

[3] Although Subpart OOOOa defines a marginal well as producing 15 barrels of oil ("bbl") (which equates to about 90 million cubic feet ("Mcf") of natural gas) per day or less, the average marginal well production in the US is much lower. The Interstate Oil and Gas Compact Commission's 2015 Marginal Wells: Fuel for Economic Growth Report ("2015 Marginal Wells Report") indicates that the average marginal oil well produces 2.0 bbls/day and average natural gas marginal well produces 14.2 Mcf/day. At such low production, profit margins are thin and additional regulatory burden could easily make many uneconomical. According to the 2015 Marginal Wells Report, the elimination of both marginal oil and natural gas wells in 2015 would result in an estimated direct loss of 57, 560 jobs in the oil and gas sector and $4.4 billion in direct earnings within the surveyed states.
See http://iogcc.ok.gov/Websites/iogcc/images/MarginalWell/MarginalWell-2015.pdf

letter to certain petitioners. That did not make the issue disappear, it was simply an expedient way to dismiss it. The issue still remains, and when the impact of low production exemption could be a "bet the farm" proposition, the EPA is certainly justified in revisiting the issue and staying those requirements.

C. The Two-Year Duration is Appropriate.

The issues raised in the Petitions for Reconsideration are numerous, and some are more complex than others. Based on the lack of reliable emissions estimates and cost estimates related to LDAR, in general, and at low production wells, specifically, it is important that the EPA interface with all stakeholders, develop an appropriate protocol for collection of emission data, and then calculate the cost of compliance – especially as it relates to small entities. Two years is an appropriate time period to undertake the aforementioned process. The Independent Producers believe many of the requirements subject to Petitions for Reconsideration are a function of the previous Administration rushing to judgment and solidifying one's legacy before leaving office. Representatives from the Independent Producers met with the EPA after Subpart OOOOa was finalized to address some of the requirements that were of greatest concern to their members, *e.g.*, removal of the low production well exemption and the requirement that a separator be onsite during well completions. The representatives explained to the EPA, for a second time (the first being with Subpart OOOO), that certain vertical wells and "energized" fractures cannot operate a separator – it is simply not technically feasible. There seemed to be some acknowledgment on the part of the EPA that the requirement for a separator onsite regardless of the type of fracture did not make sense. Revisions to provisions, such as having a separator onsite during the entire completion, might not require two years and could be proposed earlier. The Independent Producers appreciate certain advantages to waiting until a "critical mass" of issues are resolved before making a final determination on the issue for reconsideration. The Independent Producers are willing to work with EPA and stakeholders to perhaps agree on certain issues that could be addressed in less than two-years.

D. Conclusion.

The beneficial impact of the Proposed Rule to the Independent Producers and their individual members is significant. The impact of the Proposed Rule on the environment is minimal. The duration of the Proposed Rule is entirely appropriate considering the complexity of certain issues. A significant majority of the Independent Producers' concerns raised in the attached comments were not adequately addressed in the previous rulemakings associated with Subpart OOOO and Subpart OOOOa. Consequently, the Independent Producers challenged the final rules in court and petitioned the EPA for reconsideration. The EPA's Proposed Rule under the new Administration is entirely appropriate.

If the EPA has any questions or concerns, please do not hesitate to contact me.

Sincerely,

James D. Elliott

cc: Amanda Gunasekara, EPA (via E-mail)
Elliott Zenick, EPA (via E-mail)
Sarah Dunham, EPA (via E-mail)
Steve Page, EPA (via E-mail)
Peter Tsirigotis, EPA (via E-mail)
Kevin Culligan, EPA (via E-mail)
David Cozzie, EPA (via E-mail)

SPILMAN THOMAS & BATTLE, PLLC
ATTORNEYS AT LAW

James D. Elliott
717.791.2012
jelliott@spilmanlaw.com

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. <u>ADDITIONAL ISSUES IN NEED OF REVISION</u>

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

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.

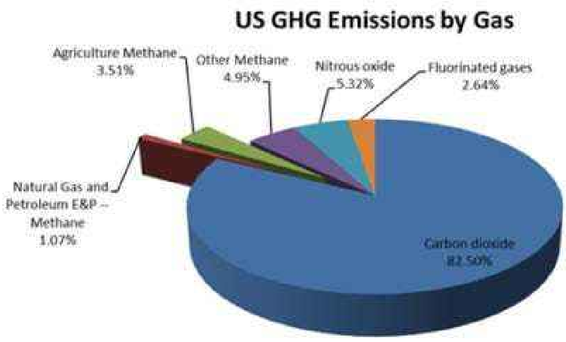
These regulations will have a serious negative economic impact on American oil and natural gas production while providing marginal environmental benefit beyond the regulations EPA promulgated in 2012 to regulate VOCs from essentially the same set of production and exploration emission sources.[3] To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

[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.

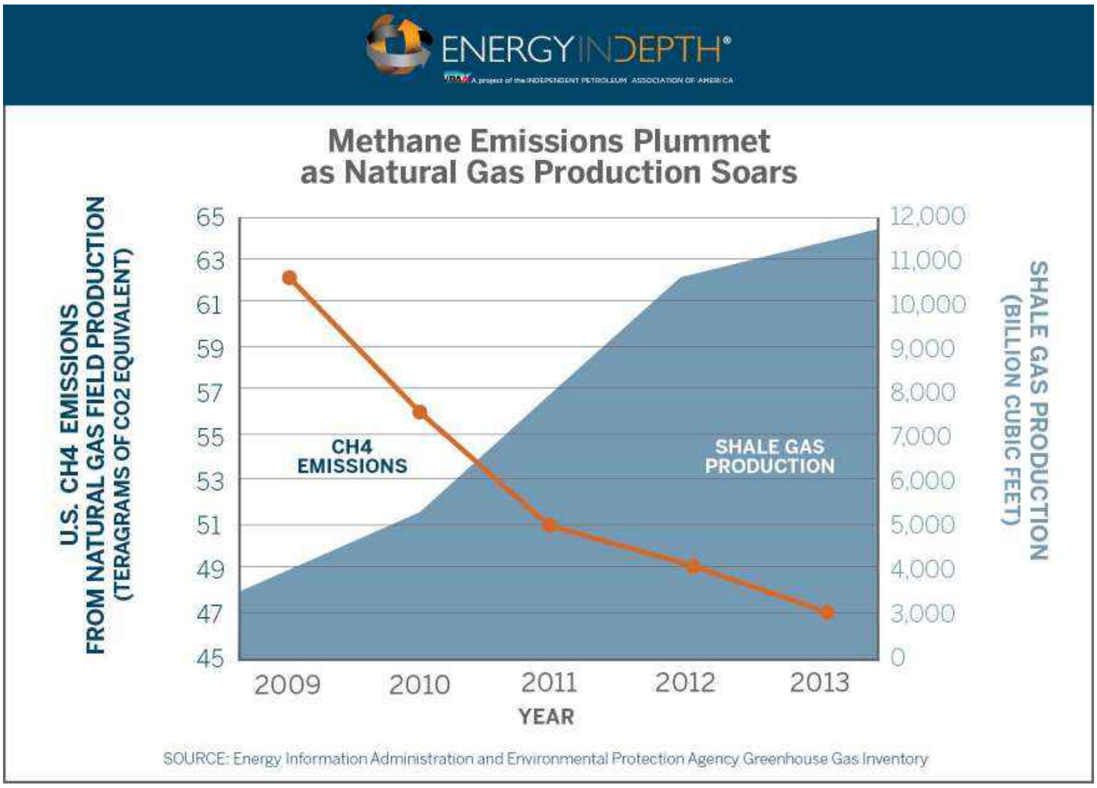
[6] Requirements for reduced emission completions on natural gas wells were promulgated in August 2012 but did not become effective until January 1, 2015. Oil and Natural Gas Sector: Reconsideration of Additional Provisions of New Source Performance Standards, 79 Fed. Reg. 79,018 (Dec. 31, 2014) (codified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



---

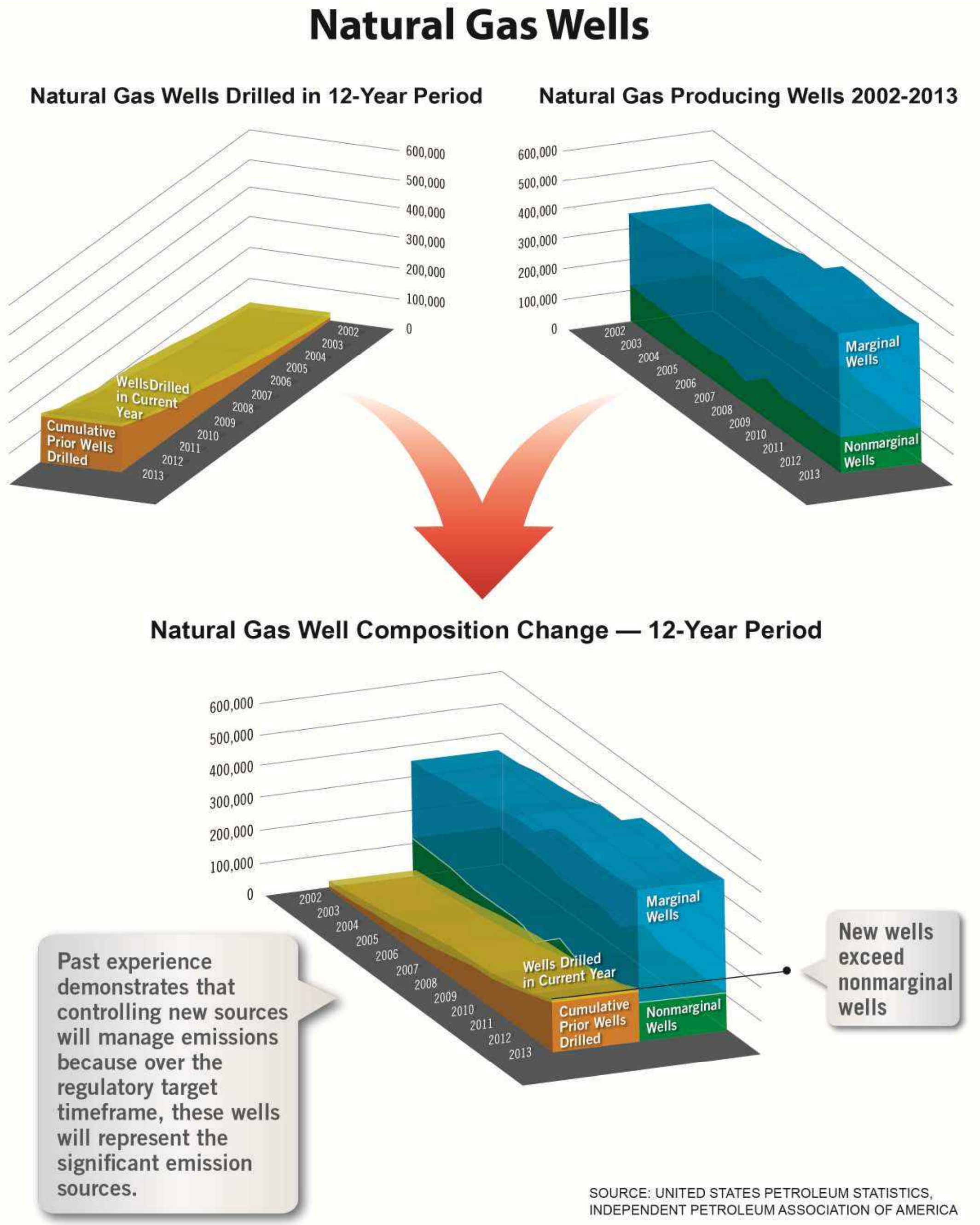
[8] *Id.*

[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.

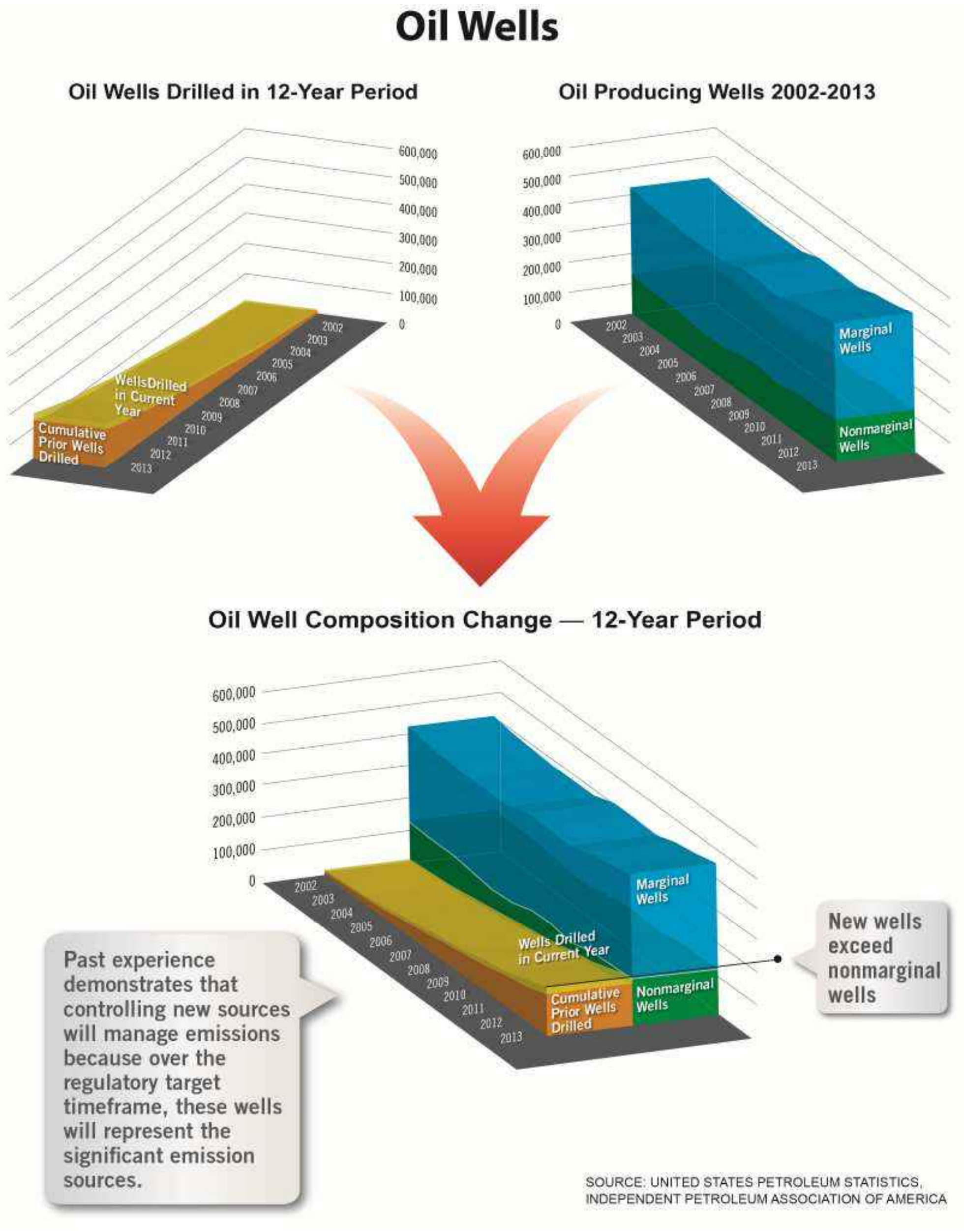
Moreover, because of the nature of oil and natural gas production, the application of controls on new sources will achieve the Administration's objectives without the need to create extensive existing source regulations. Oil and natural gas production operations differ from other types of manufacturing. 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:



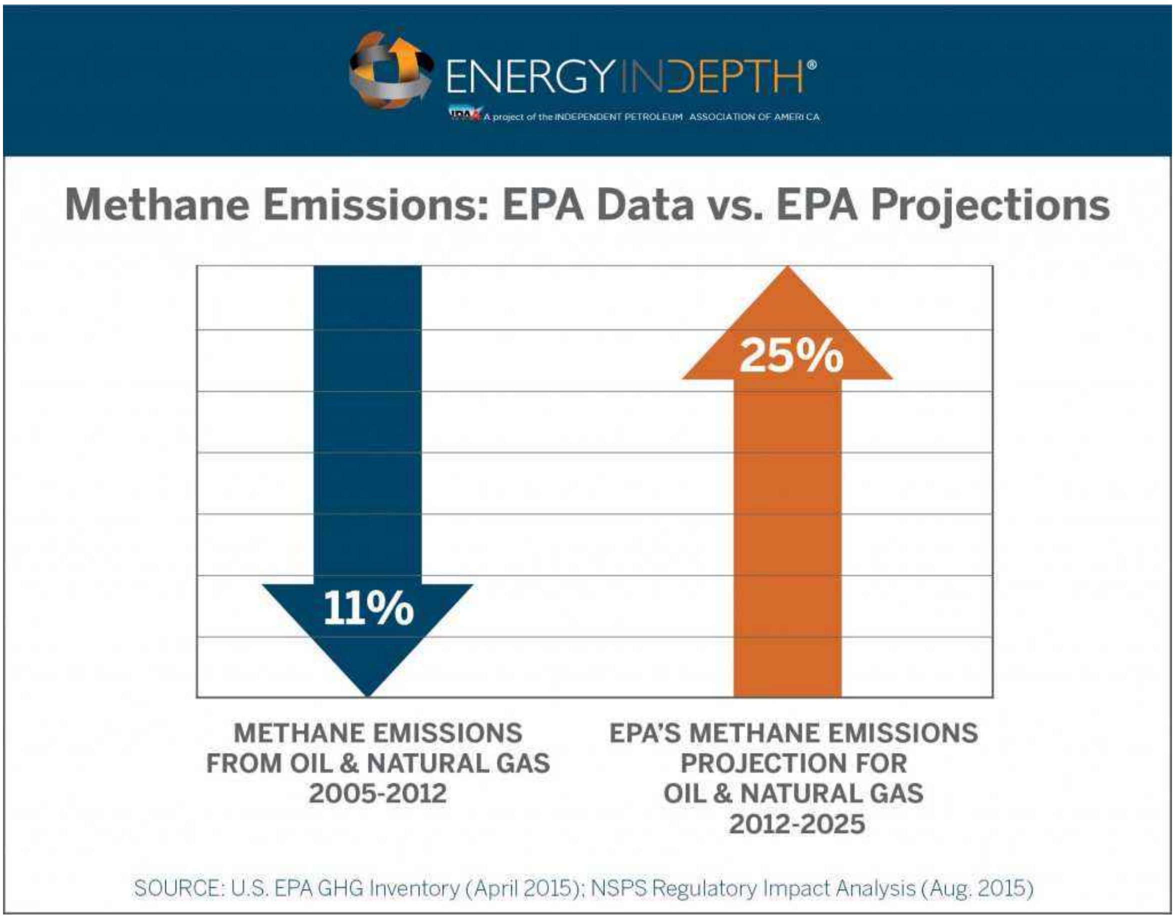
As this graphic demonstrates, after 12 years wells subject to the new source regulatory requirements will dominate the production of natural gas, and the remaining wells will be marginal wells with minimal incremental emissions beyond the emissions from sources already subject to regulation. The cost 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 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.

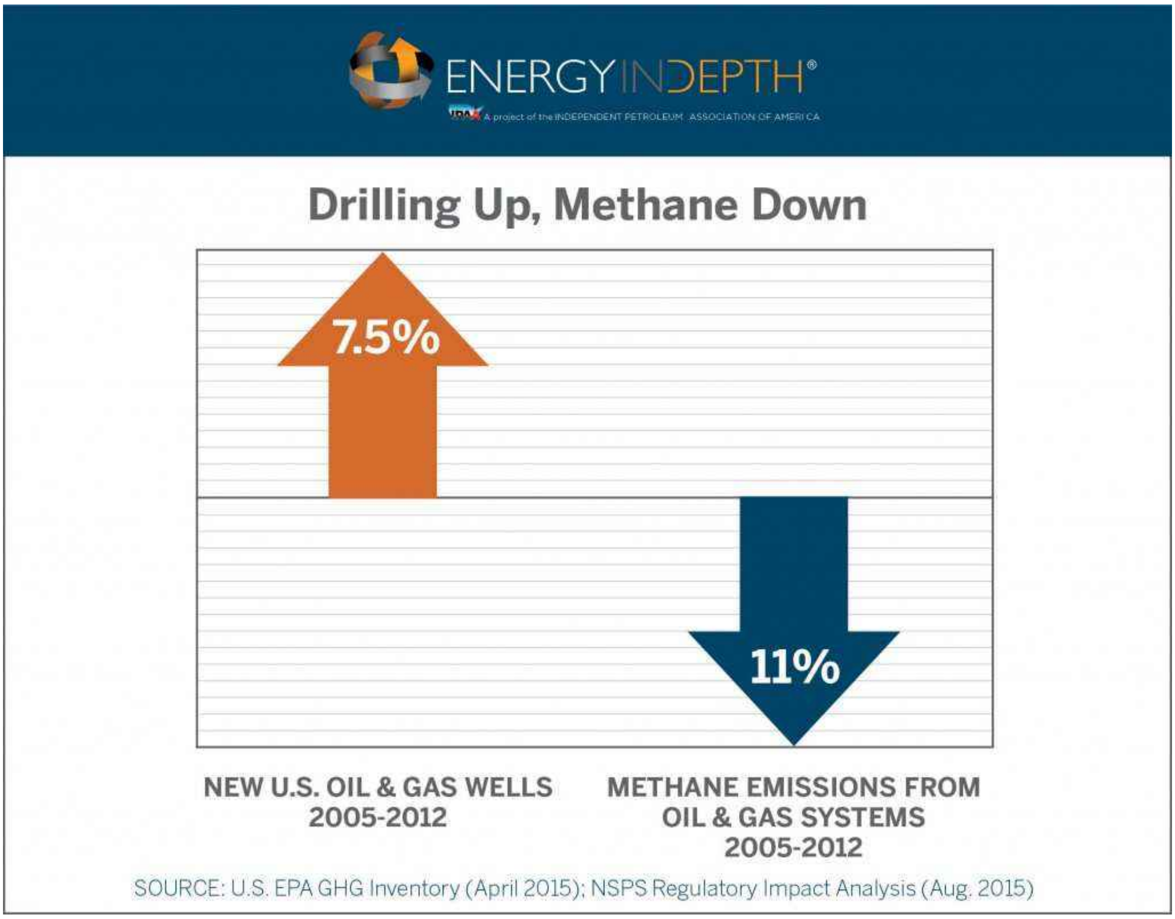


More specifically, Energy In Depth found:

- 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.

---

[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

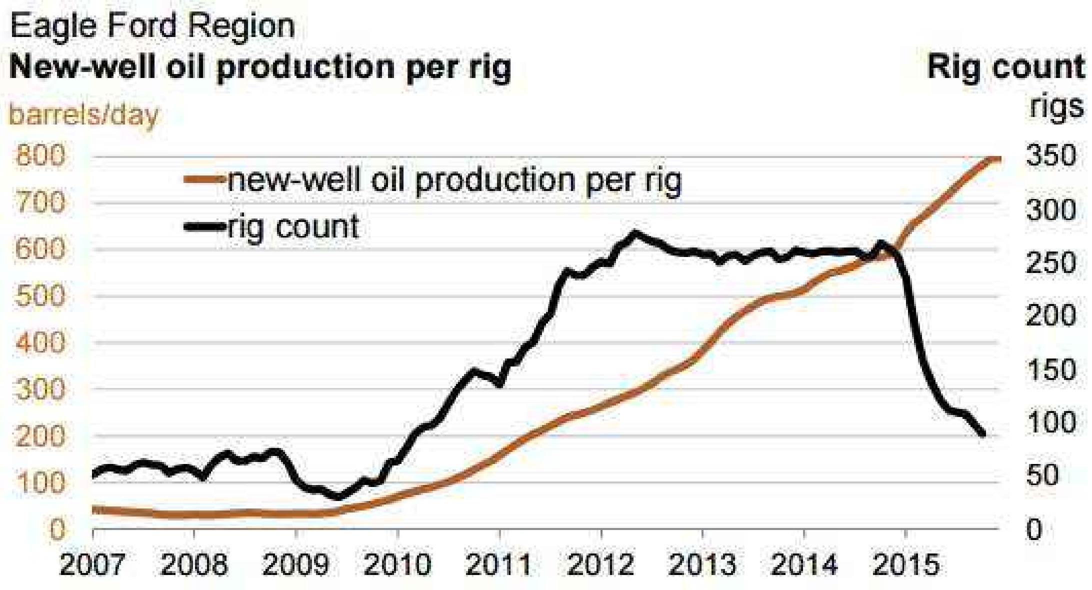
EPA justifies its proposed regulations in large part on the last 10 years of growth in the American oil and natural gas industry – perhaps the most dynamic and rapid growth period in the history of the industry:

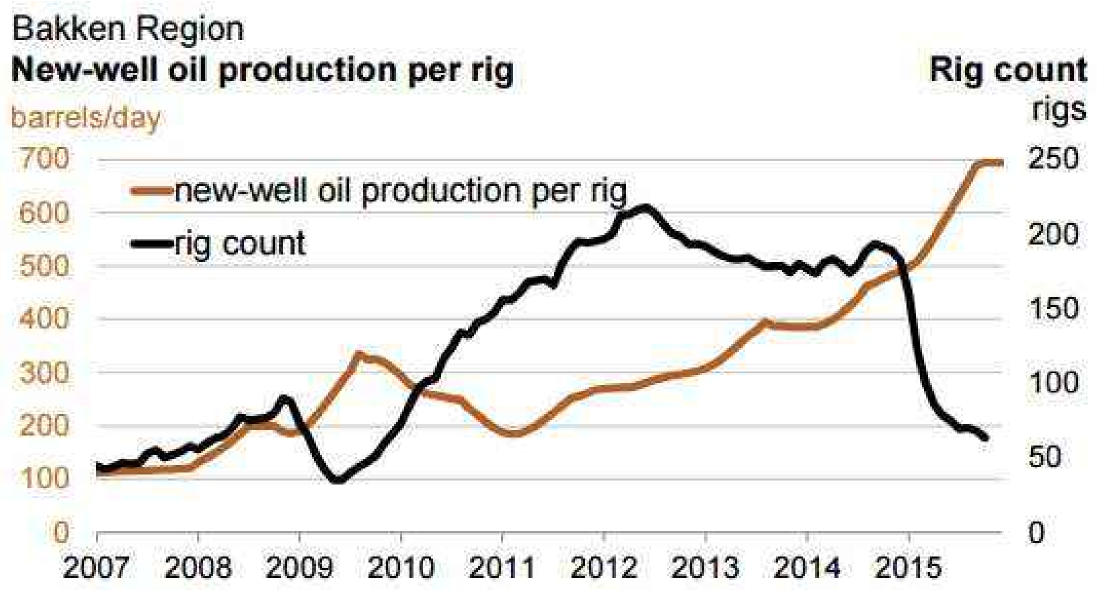
> The EPA has projected affected facilities using a combination of historical data from the U.S. GHG Inventory, and projected activity levels, taken from the Energy Information Administration (EIA's) Annual Energy Outlook (AEO). The EPA derived typical counts for new compressors, pneumatic controllers, 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/.





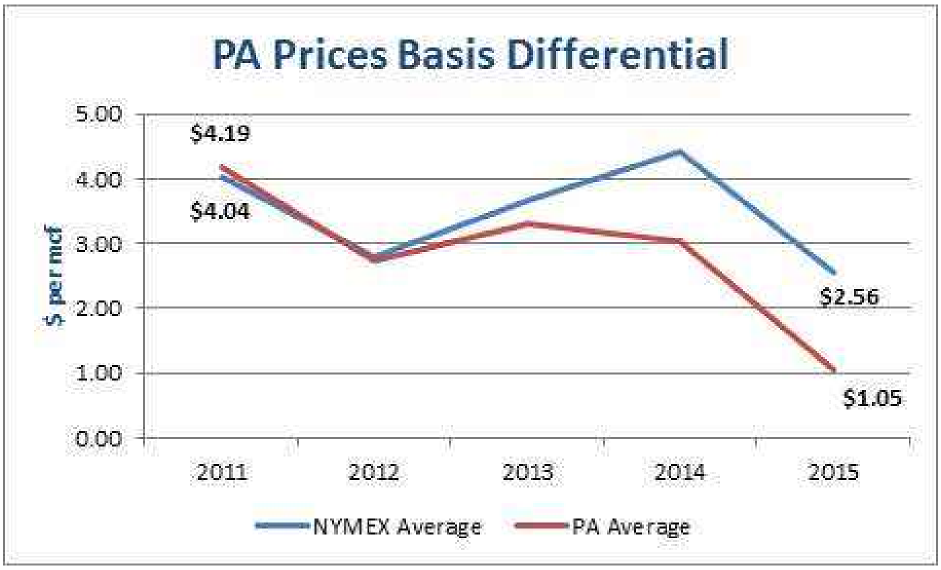
SOURCE: U.S. Energy Information Administration

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

[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.

---

[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.

---

[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]

[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

[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

[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.

[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

[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.
>
> See the comments above, as they pertain to EPA's data sources and estimates.
>
> 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).
>
> . . .
>
> 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.
>
> 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. Miscellaneous Requests for Input

- 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:

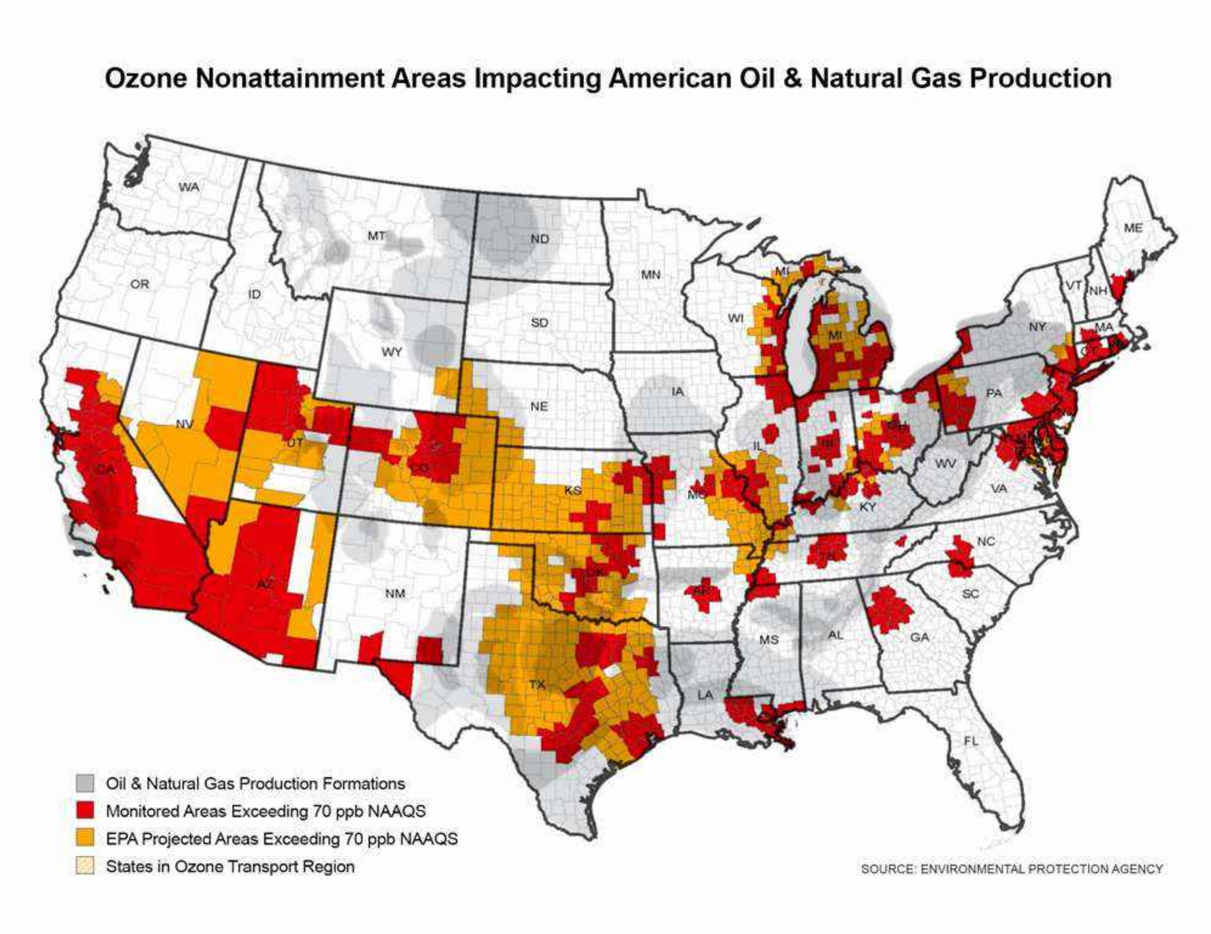
> For purposes of this guideline, the emissions and programs to control emissions discussed herein would apply to the collection of fugitive emissions components at a well site with an average production of greater than 15 barrel equivalents per well per day (15 barrel equivalents), and the collection 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.

---

[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.



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.

---

[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.

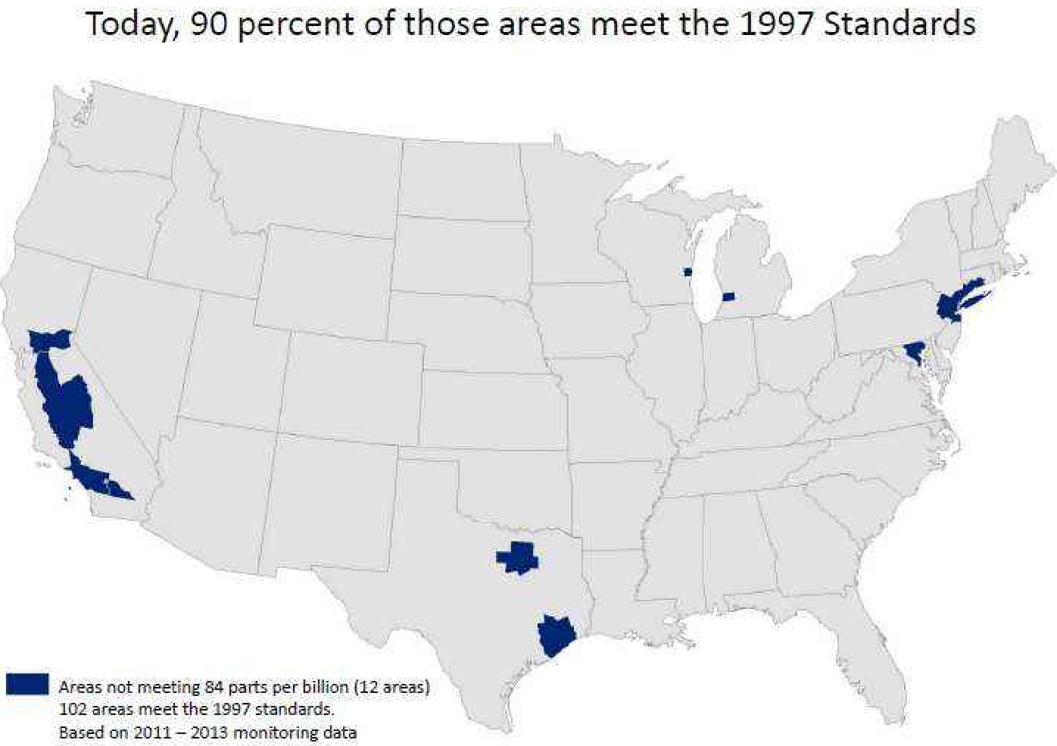


Figure 1

Source: Environmental Protection Agency

Figure 2

Source: Environmental Protection Agency

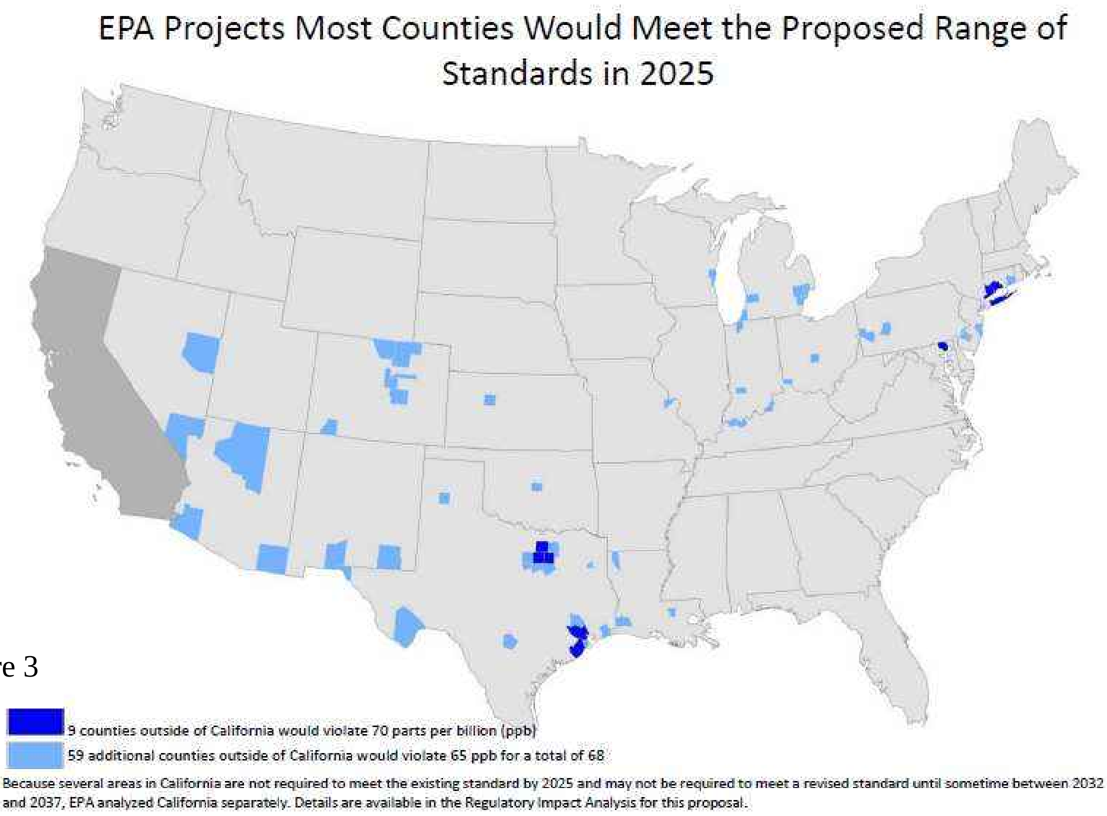


Figure 3

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.

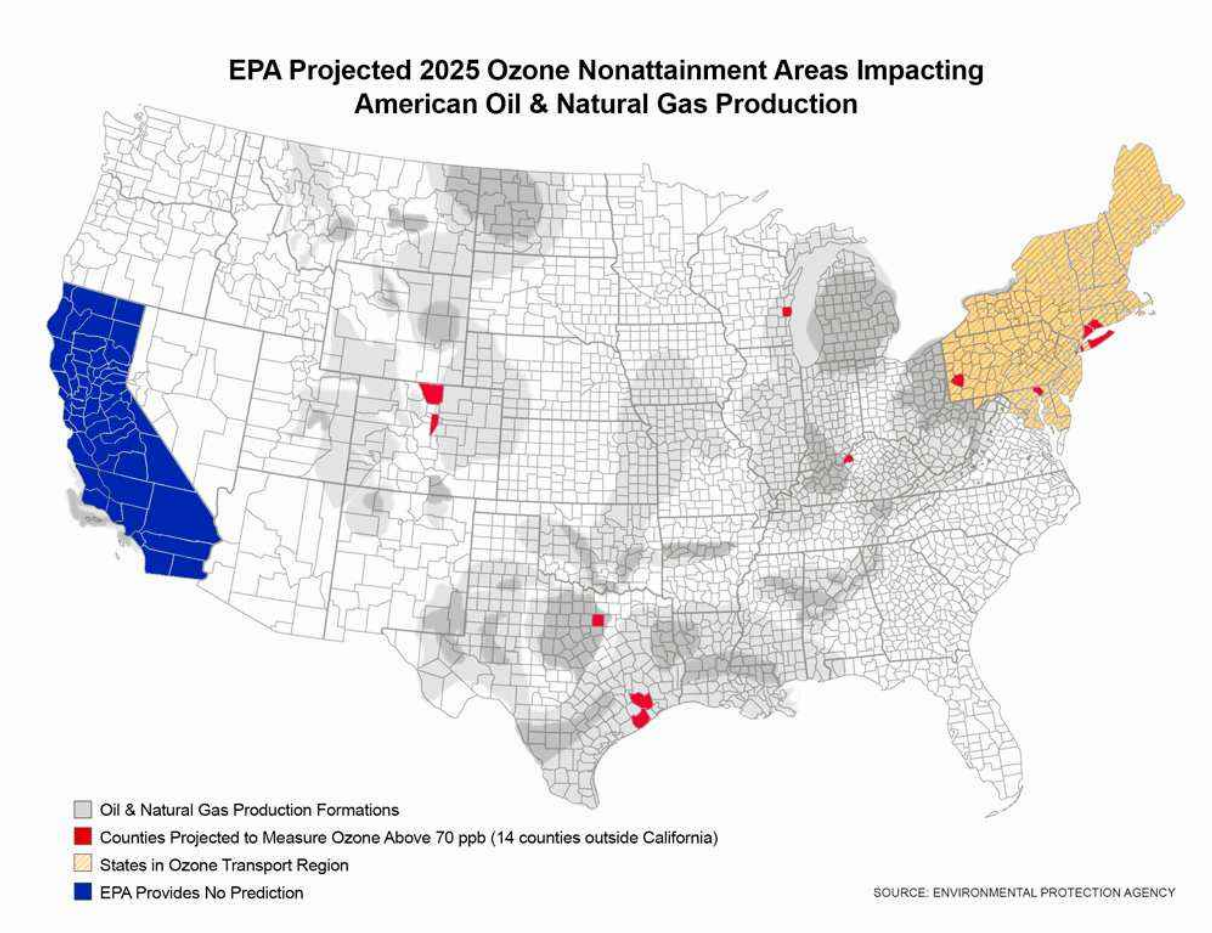
For these areas that EPA projects would reach attainment using only national, federal mandates regardless of the NAAQS, promulgating the lower NAAQS will compel them to be subject to the requirements of Part D of the CAA. Because Part D imposes a series of minimum requirements, the revised NAAQS will 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. <u>Fugitive Emissions</u>

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.

[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		Gas Wells	
	Average Oil Production Rate per Oil Well (bbl/day)[b]	Crude Oil Storage Vessel VOC Emissions (tpy)[c]	Average Condensate Production Rate per Gas Well (bbl/day)[b]	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

[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

---

[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

SPILMAN THOMAS & BATTLE, PLLC
ATTORNEYS AT LAW

James D. Elliott
(717) 791-2012
jelliott@spilmanlaw.com

April 22, 2015

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

VIA ELECTRONIC MAIL

RE: Comments of the Independent Petroleum Association of America, Independent Oil and Gas Association of West Virginia, Inc., Kentucky Oil & Gas Association, Inc., Pennsylvania Independent Oil & Gas Association, Ohio Oil and Gas Association, Illinois Oil and Gas Association, Indiana Oil and Gas Association and the Virginia Oil and Gas Association -- Oil and Natural Gas Sector: Definitions of Low Pressure Gas Well and Storage Vessel; Docket ID No. EPA-HQ-OAR-2010-0505.

Dear Administrator McCarthy:

The Independent Petroleum Association of America ("IPAA"), Independent Oil and Gas Association of West Virginia, Inc., Kentucky Oil & Gas Association, Inc., Pennsylvania Independent Oil & Gas Association, Ohio Oil and Gas Association, Illinois Oil and Gas Association, Indiana Oil and Gas Association, and the Virginia Oil and Gas Association (collectively, the "Independent Producers") appreciate the opportunity to submit comments on the proposed rule entitled "Oil and Natural Gas Sector: Definitions of Low Pressure Gas Well and Storage Vessel" ("Proposed Rule") and published in the Federal Register on March 23, 2015 (80 Fed. Reg. 15180).

As discussed in the comments filed by the Independent Producers on the July 17, 2014 proposed amendments to the original New Source Performance Standards ("NSPS") for the oil and natural gas sector, the above associations came together, in large part, to comment on the original rule (individually, or as a member of IPAA), published on August 16, 2012; petition the United States Environmental Protection Agency ("EPA") for reconsideration on October 15, 2012; and file a legal challenge in the United States Court of Appeals for the District Circuit to the August 16, 2012 final rule because there are aspects of the final rule that disproportionally impact conventional wells and energized wells – particularly as it relates to reduced emission completions ("RECs"). As noted in the March 23, 2015 Federal Register notice, the Independent Producers comments on the July 17, 2014 proposed rule were timely filed on August 18, 2014 but not included in the record and not considered or addressed in the final rule published

December 31, 2014. Pursuant to EPA's instructions in the Proposed Rule, the Independent Producers are not repeating or resubmitting their August 18, 2014 comments but simply requesting that the EPA incorporate them by reference with these comments.

The Proposed Rule asks for comments on primarily two issues: the definition of a "storage vessel" and the definition of a low pressure well. For the reasons set forth in the preamble, the Independent Producers support the revisions to remove the "connected in parallel" and "installed in parallel" language from the definitions of "returned to service" and "storage vessel" in 40 C.F.R. § 60.5430. While the terms "connected in parallel" and "installed in parallel" may have been included in the definitional terms inadvertently, the changes might be read to significantly expand the scope of the NSPS. The Independent Producers appreciate EPA explaining that it was not the intent of EPA to expand the scope of the NSPS and it was moving relatively quickly to rectify the mistake. As discussed in the Gas Processors Association request for administrative reconsideration, storage vessels have historically been placed next to each other and sometimes operated in parallel or in series – with no intent of decreasing emissions from each tank. Obviously, there is an incentive to keep emissions from a storage vessel below the 6-ton per year applicability threshold – and the regulations contemplate ways to do that legally. EPA has explained its concern and taken the steps necessary to forewarn industry that connecting storage vessels in parallel to circumvent the NSPS 6-ton threshold is not allowed under the regulations.

The Independent Producers concern with EPA's definition of a low pressure well – from the beginning in 2012 – is that it does not accurately define what industry has historically defined and recognized as a low pressure well. Additionally, because EPA's definition does not accurately delineate low pressure wells, the NSPS, as proposed, will subject a subset of wells to RECs where the operation of a separator is not physically possible thereby making the wells uneconomical as a result of being subject to REC requirements. The Independent Producers' August 18, 2014 comments reference Exhibit 5 of Lessons Learned from Natural Gas STAR Partners; Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells which discusses the volume of gas required to lift liquids – a parameter associated when RECs are feasible. Building on Exhibit 5 and utilizing the limited variables within EPA's definition (reservoir pressure and sales line pressure), the following Table shows the difference between EPA's definition and industry's proffered definition. Industry would consider all of the combinations of well depth and sales line pressure in the Table as a low pressure well. Whereas EPA's definition would only define the cells in red as "low pressure" wells.

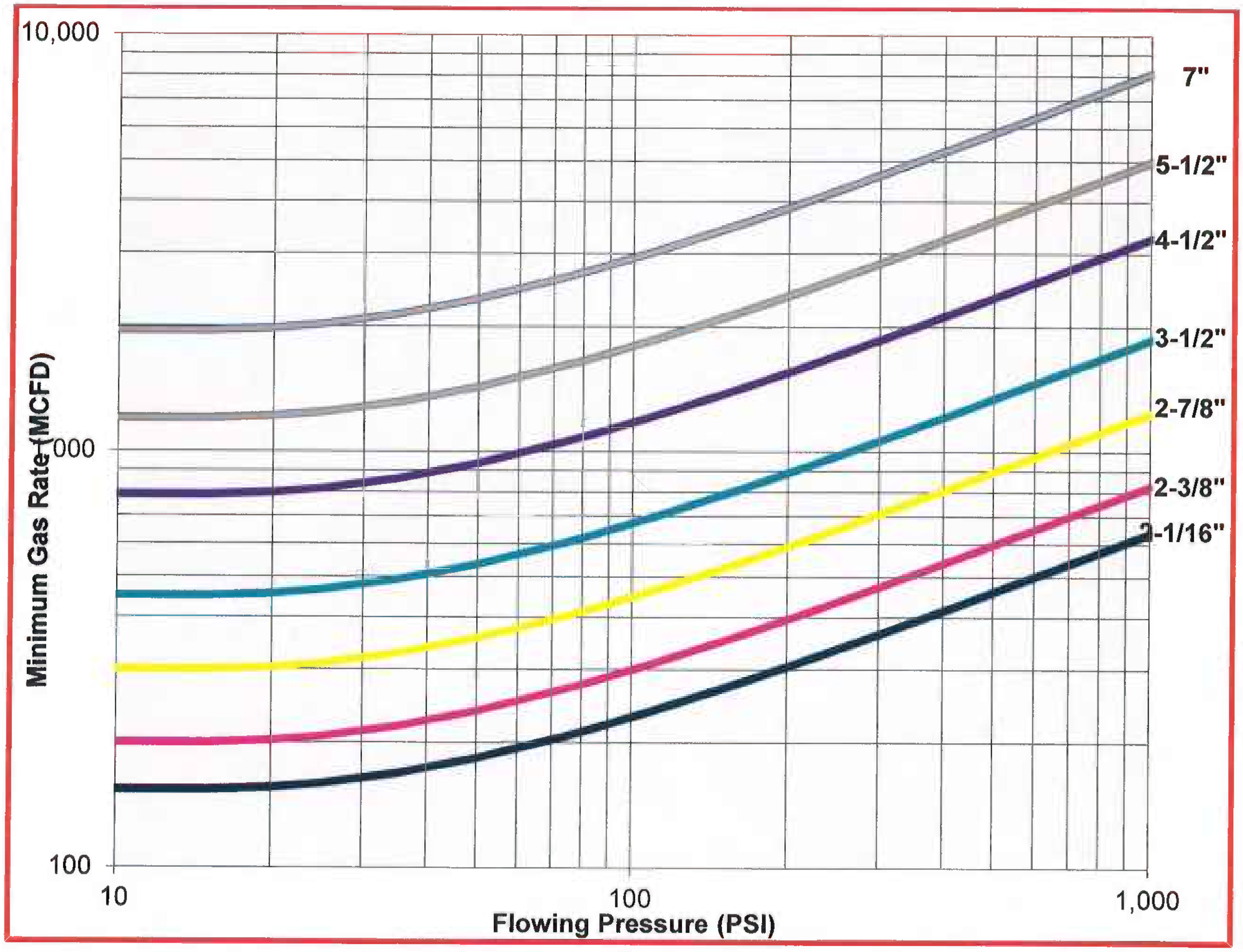
Reservoir Pressure 0.4645 psi/ft

Flowline Pressure / Reservoir Depth	25	50	100	200	300	400	500	600	700	800	900	1000	1100	1200
1000	76	51	1	(99)	(199)	(299)	(399)	(499)	(599)	(699)	(799)	(899)	(999)	(1099)
2000	245	220	170	70	(30)	(130)	(230)	(330)	(430)	(530)	(630)	(730)	(830)	(930)
3000	414	389	339	239	139	39	(61)	(161)	(261)	(361)	(461)	(561)	(661)	(761)
4000	582	557	507	407	307	207	107	7	(93)	(193)	(293)	(393)	(493)	(593)
5000	751	726	676	576	476	376	276	176	76	(24)	(124)	(224)	(324)	(424)
6000	920	895	845	745	645	545	445	345	245	145	45	(55)	(155)	(255)
7000	1088	1063	1013	913	813	713	613	513	413	313	213	113	13	(87)
8000	1257	1232	1182	1082	982	882	782	632	582	482	382	282	182	82
9000	1426	1401	1351	1251	1151	1051	951	851	751	651	551	451	351	251
10000	1594	1569	1519	1419	1319	1219	1119	1019	919	819	719	619	519	419
11000	1763	1738	1688	1588	1488	1388	1288	1188	1088	988	888	788	688	588
12000	1932	1907	1857	1757	1657	1557	1457	1357	1257	1157	1057	957	857	757

^((0.445 psi/ft * TVD* Resv_Pressure_Grad)-(0.038 psi/ft * TVD)-67.578 psi) -Sales Line Pressure in psi

The data presented in this Table demonstrates the limitations of EPA's definition. Reducing the definition of a low pressure well to a mathematical formula that can be calculated on a "basic hand-held calculator " fails to capture the complex reality of when a particular well is "under pressured" and not able to overcome the pressure associated with a column of water and sales line pressure. The permeability of the reservoir and other reservoir characteristics play a critical role in determining when a well is low pressure well or under-pressured. In addition to overcoming the hydrostatic pressure and sale line pressure, the separator necessary for the REC adds to the pressure which must be overcome for gas to flow from the reservoir. The separator pressure is arguably the controlling parameter on when a REC is feasible versus the sales line pressure. Unlike the sales line pressure, which is easily known, separator pressure can vary greatly depending on gas and liquid rates, liquid composition and equipment limitations. EPA's definition does not take separator pressure into account thereby making the definition overly conservative. Admittedly, the alternative definitions provided by the Independent Producers does not contain an adjustment for separator pressure either, but nonetheless, for the reasons set forth in the August 18, 2014 comments, the definition is more accurate and is inclusive of wells recognized by the industry as "low pressure".

The reality is that a "low pressure" or "under-pressured" well is not easily defined by simply entering well depth and reservoir pressure into a handheld calculator. In addition to the pressure associated with the separator, in order for a separator to function, there must be a sufficient volume of gas (at appropriate pressure) to lift the associated liquids and overcome the pressure of the separator. If that gas rate is not achieved, the well will load up and a REC will not be possible. The gas rate necessary for a REC varies based on reservoir pressure and casing/tubing diameter. The following Coleman curves illustrate this point.



SPE20280 A New Look at Predicting Gas-Well Load-Up, Coleman, Clay, McCurdy, Norris. As the pressure and casing diameter increase, so must the gas rate. Again – without sufficient gas volume, the well will not be able to lift liquids and a REC will not be possible. In reality, most wells produce a significant fraction of liquids during flowback and early production. Wells with low reservoir pressure are particularly susceptible to liquid loading. This is further exasperated by the fact that during stimulation these wells are often being flowed-back up large diameter casing rather than tubing – thus requiring greater gas rate and pressure from the reservoir (see Coleman Curves). Certain wells require artificial lifts to assist in the liquid unloading. If the well requires an artificial lift, the well is clearly a low pressure well.

The Independent Producers have pursued an accurate, workable definition of low pressure for over three years at this point. We have met with and discussed the issue multiple times with EPA. Both sides have searched for a simple, clear formula or bright line. In the field, it's not that easy – there is a "certain art" or technique associated with the science. EPA is concerned that operators will try to circumvent the REC requirements by claiming to be a low pressure well. The reality is that if a REC is feasible, the operator has the economic motivation to undertake the REC. But there is a category of wells, low pressure wells, where RECs are not only uneconomical, but it is not technically feasible. The Independent Producers generally support the preamble discussion of "technical feasibility" in the December 31, 2014 rule as it pertains to the difference between the initial flowback stage and separation flowback stage. That discussion is also applicable to the ability of low pressure wells to conduct RECs. Reducing subjective calls based on fact specific situations and engineering judgment to a mathematical formula or descriptive narrative is extremely difficult if not impossible. It is akin to the United States Supreme Court Justice Potter Stewart's discussion of obscenity – "I know it when I see it . . . ." The Independent Producers appreciate that a regulatory scheme cannot and should not be that subjective. Neither EPA's definition nor the Independent Producers' definition is perfect. But based on the input of the operators in the field and the technical consultants/engineers familiar with low pressure wells[1], the alternative definitions provided by the Independent Producers are more accurate than EPA's definition.

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

Sincerely,

James D. Elliott (SDS)

James D. Elliott

cc: Bruce Moore
Amy Branning
Lee Fuller, IPAA Vice President of Government Relations
Charlie Burd, IOGA-WV Executive Director
Andrew V. McNeill, KOGA Executive Director
Lou D'Amico, PIOGA Executive Director
Shawn Bennett, OOGA Executive Vice President
Matt Stone, INOGA President
Brad Richards, IOGA Executive Vice President
Greg Kozera, VOGA President

[1] It should be noted that these comments and previous comments relate only to "low pressure gas well." As EPA contemplates potential controls on low pressure oil wells, the Independent Producers respectfully request the opportunity to discuss what emission controls for oil wells MAY be warranted.

James D. Elliott
(717) 791-2012
jelliott@spilmanlaw.com

August 18, 2014

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

VIA ELECTRONIC MAIL

RE: Comments of the Independent Petroleum Association of America, Independent Oil and Gas Association of West Virginia, Inc., Kentucky Oil & Gas Association, Inc., Pennsylvania Independent Oil & Gas Association, Ohio Oil and Gas Association, Illinois Oil and Gas Association, Indiana Oil and Gas Association and the Virginia Oil and Gas Association -- Oil and Natural Gas Sector: Reconsideration of Additional Provisions of New Source Performance Standards; Docket ID No. EPA-HQ-OAR-2010-0505.

Dear Administrator McCarthy:

The Independent Petroleum Association of America, Independent Oil and Gas Association of West Virginia, Inc., Kentucky Oil & Gas Association, Inc., Pennsylvania Independent Oil & Gas Association, Ohio Oil and Gas Association, Illinois Oil and Gas Association, Indiana Oil and Gas Association, and the Virginia Oil and Gas Association (collectively, the "Independent Producers") appreciate the opportunity to submit comments on the proposed rule entitled "Oil and Natural Gas Sector: Reconsideration of Additional Provisions of New Source Performance Standards" ("Proposed Rule") and published in the Federal Register on July 7, 2014 (79 Fed. Reg. 41752).

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 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 the state.

The Kentucky Oil & Gas Association, Inc. ("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 Pennsylvania Independent Oil & Gas Association ("PIOGA") is a non-profit corporation that was initially formed in 1978 to represent the interests of smaller independent producers of Pennsylvania natural gas from conventional limestone and sandstone formations. Through the years PIOGA's membership has grown to nearly 1,000 members: oil and natural gas producers, 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 in both conventional geologic formations and unconventional shale formations, and the development of competitive markets and additional uses for Pennsylvania-produced natural gas.

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.

Indiana Oil and Gas Association, Inc. ("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

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.

Formed in 1977 the Virginia Oil & Gas Association ("VOGA") is a non-profit trade association representing the interests of companies, partnerships, individuals, or other entities having an interest in the oil and gas industry and who are primarily engaged in the exploration, production, development, transportation, and distribution of natural gas and oil in Virginia.

The above associations came together, in large part, to comment on the original rule (individually, or as a member of IPAA), published on August 16, 2012; petition the United States Environmental Protection Agency ("USEPA") for reconsideration on October 15, 2012; and file a legal challenge in the United States Court of Appeals for the District Circuit to the August 16, 2012 final rule because there are aspects of the final rule and Proposed Rule that disproportionally impact conventional wells and energized wells – particularly as it relates to reduced emission completions ("RECs"). The history and activities of the above associations are relevant because of the depth of knowledge and unique position that many of their members have within the industry. The Independent Producers appreciate that the USEPA has recognized the proposed definition of a "low pressure well" proffered by the Independent Producers, but we are concerned that the USEPA continues to misunderstand our concerns and has not justified its definition of a low pressure well.

USEPA's preamble discussion of the low pressure well definition misses the point. It states in relevant part:

> [T]he three parameters discussed above and used in the EPA definition are known by operators in advance of flowback and that the relatively simple calculation called for in the EPA definition could be performed with a basic hand-held calculator and should not pose difficulty or hardship for the smaller operators.

79 Fed. Reg. 41758. The "hardship" is not the calculation. The hardship is being required to perform RECs on marginally cost-effective wells that industry has historically recognized as low pressure wells. While the ultimate calculation may be completed on a "basic hand-held calculator," it does not mean that the derivation of the formula or the results of the calculation accurately depicts what constitutes a low pressure well.

Additionally, the preamble takes issue with the Independent Producers petition for reconsideration because it "did not include any details on which of EPA's assumptions is questionable . . .." *Id.* While we provide details in these comments, USEPA's statement requires that we emphasize that the burden to justify the rule is on USEPA, not the Independent Producers or any other commenters. One of the key assumptions to the USEPA's definition is its reliance on the Turner equation to calculate the minimum gas velocity needed to lift a droplet.[1] This equation is used to predict the velocity needed to lift to the surface the proppant used to hydraulically fracture the well. The Turner equation is from a 1969 article in the Oil and Gas Journal.[2] The equation is based on a droplet reversal model. Independent Producers are not aware of the oil and gas industry using the Turner equation for any practical applications (unlike Independent Producers' proposed definition which relies on industry accepted calculations).

---

[1] 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, pp. 34-37 (April 2012).

[2] Turner, R. G., *et. al.*, *Analysis and Prediction of Minimum Flow Rate for the Continuous Removal of Liquids from Gas Wells*, Journal of Petroleum Technology, Nov. 1969, Equation 4, at 1476.

Independent Producers site a *recent* engineering doctoral dissertation at the Tulsa University that compared several methods of calculating liquid loading in a well, which it is relevant as it pertains to the equations used by USEPA to develop a definition of a low pressure well. The dissertation was delivered by Dr. Shu Luo, a graduate student at Tulsa University, in 2013. His advisor was Dr. Mohan Kelkar, head of the Petroleum Engineering Department. Dr. Lho's abstract follows.

> When natural gas is produced from gas wells, it is always accompanied by liquid. At the later stages of a well's life, the gas is unable to carry liquid to the surface, resulting in liquid accumulation at the bottom of the well; this is called "Liquid Loading". Knowing when the liquid loading will occur is important because by using certain artificial lift methods the well can be produced under stable conditions even after the transition. The most popular method in the literature for determining the onset of liquid loading is the equation developed by Turner et al. This equation is a droplet model and is based on the terminal velocity of liquid droplet in single phase gas column. Many modifications have been proposed to this equation to improve the prediction of liquid loading. Recently, Veeken et al. have shown that in many inclined and some vertical wells, Turner's equation under-predicts the true critical flow rate (the flow rate at which liquid loading starts). This may be due to angle of deviation as well as the fact that inception of liquid loading is more likely due to liquid film reversal in annular flow rather than droplet fall back.
>
> In this dissertation, the inception of liquid loading is defined using the liquid film reversal model based on experimental observation. Also, a new liquid loading model which is based on liquid film reversal is proposed. We base our model on Barnea's model and make several improvements to that model for better prediction of liquid loading. The improvements include: (i) development of variable film thickness model to account for the deviation angle of the well; (ii) development of equation to account for annular flow; and (iii) improvement of the friction factor equation at the interface between the liquid film and the gas core. We validated our model against all the available data from the literature as well as additional data collected from various operators. The results show remarkable improvement over Turner's original method as well as various ad hoc modifications made to that equation. A method which determines the unloading of a gas well after shut in will also be discussed.
>
> In this dissertation, we also explore one possible method to eliminate liquid loading. Injection of surfactant is one of the common methods used for avoiding liquid loading in gas well. Using our definition of liquid loading, the stability of foam flow can be predicted. We also propose a correlation for liquid holdup in foam flow and compare the predictions with experimental data. Based on the large scale experimental data, we

> provide a preliminary model for predicting foam flow and articulate reasons why the foam works in preventing liquid loading.[3]

In relevant part, according to the recent research, the Turner equation typically under-predicts the velocity necessary to unload the well. Since the Turner equation under-predicts velocity, the resulting USEPA low pressure well formula then also under-predicts the pressure necessary for a well to flowback without assistance. For instance, to increase velocity in the well tubing, which has a fixed flow area, the flow rate of gas must be increased to carry the liquid up the tubing. To increase the flow rate within a given pipe size, pressure must increase. Operators will sometimes install smaller tubing to decrease flow area, which also increases velocity. This is one example of where USEPA's derivation of a complex equation to define low pressure well is flawed. A more accurate low pressure well definition should rely on the liquid film reversal model versus the Turner equation, and result in a higher pressure threshold than currently proposed by the USEPA. Again, the burden is on USEPA to justify its definition and not to simply question the alternative definition proposed by the Independent Producers. USEPA's reliance on an outdated equation not recognized or utilized by the industry is inappropriate.

As to the Independent Producers' alternative definition of a low pressure well, Independent Produce proposed the following more simple definition for "low pressure well."

> "A well where the field pressure is less than 0.433 times the vertical depth of the deepest target reservoir and the flow-back period will be less than three days in duration."

This definition was based on the weight of fresh water (8.33 lbs/gal) which is stacked on top of itself, and is known as hydrostatic pressure. Converting the density of fresh water to a pressure gradient results in 8.33 lb/gal being equal to 0.433 psi/ft. Therefore, the pressure of fresh water in the well bore is 0.433 psi/ft times the vertical well depth.

In reality, the fluid flowing to the surface could be fresh water, re-used hydraulic fracturing water, re-used produced water, or a mixture. Additionally, in the beginning of the operation, the initial fluids flowing to the surface are essentially the fracturing fluids put down hole. At the end of the operation, the fluids flowing to the surface will mainly consist of reservoir fluids, and the water will be more of a brine water and not fresh water. Brine water has a greater density, and more reservoir pressure will be required to lift the fluid to the surface. The use of a fresh water gradient of 0.433 psi/ft should be used to keep the definition conservative and simple.

As an alternative – or in addition – to a fresh water gradient, the density of brine water influenced by sand or proppant should be used to more accurately reflect the pressure of the water column in the well bore. In fact, USEPA appears to have utilized a gradient of 0.4645 psi/ft in the "Lessons Learned from Natural Gas STAR Partners; Reduced Emissions

---

[3] Luo, Shu, Inception of liquid loading in gas wells and possible solutions, Ph.D. diss., The University of Tulsa, 2013.

Completions for Hydraulically Fractured Natural Gas Wells" paper developed as a part of USEPA's Natural Gas STAR Program.[4] This is evidenced by the gradients listed in Exhibit 5 of the paper. A copy of this paper is provided as Attachment 1. Additionally, to perform a REC, the downhole reservoir pressure must be sufficient enough to lift the hydraulic fracturing fluid to the surface and through the separation equipment and piping, with the resulting gas still having enough back pressure for it to get into the natural gas gathering line. To combust flowback emissions, the downhole reservoir pressure must be sufficient enough to lift the hydraulic fracturing fluid to the surface and through the separation equipment and piping, with the resulting gas still having enough back pressure to flow to a flare or enclosed combustion device.

To reflect these realities, Independent Producers proposes to the USEPA that no emission control be required when the following scenario exists:

> "A well where the reservoir pressure is less than 0.4645 times the vertical depth of the deepest target reservoir."

At reservoir pressures below this value, enough pressure does not exist for any gas to flow to a flare, enclosed combustion device or the process. Consequently, the Independent Producers propose to the USEPA that combustion through a flare or enclosed combustion device be required when the following scenario exists:

> "A well where the reservoir pressure is less than 0.4645 times the vertical depth of the deepest target reservoir plus the gathering or sales line pressure."

At reservoir pressures less than the sum of the water column pressure and the sales line pressure, the recovered gas will not naturally flow into the sales line. The Proposed Rule does not require compression of recovered gas into the sales line. USEPA has recognized this type of simpler approach in estimating the level of pressure necessary for recovered gas to flow into a gathering or sales line in their "Lessons Learned from Natural Gas STAR Partners; Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells" paper developed as a part of USEPA's Natural Gas STAR Program.[5] In this paper, USEPA provides a table (Exhibit 5) with pressures necessary for various well depths. For instance, USEPA indicates that the reservoir pressure necessary to flow recovered gas into a sales line for a 10,000-foot well would be 4,645 psig plus the sales line pressure.

The definition of a low pressure well is relevant to the revised stages of flowback and helps illustrate the problem and concern of those drilling low pressure wells. The Independent Producers generally support USEPA's proposed definitions for the stages of flowback from a

---

[4] USEPA; Lessons Learned from Natural Gas STAR Partners; Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells; 2011. http://www.epa.gov/gasstar/documents/reduced_emissions_completions.pdf
[5] *Id.*

well. In the USEPA proposal for the second round of reconsideration rulemaking,[6] three (3) new terms are proposed:

- Initial flowback stage
- Separation flowback stage
- Production stage

During the initial flowback stage, USEPA has indicated that there is not enough gas to operate a separator. Gas generated during the initial flowback stage would not be controlled under the proposal. USEPA acknowledges that during the separation flowback stage there may not be enough gas to operate a separator, with the gas either combusted or recovered depending on the well type according to the proposal. For certain lower pressure wells (that most likely would not meet the USEPA proposed definition of a low pressure well), the overall flowback period (all three stages) is so short that there is an insufficient amount of gas generated during the separation flowback stage to be able to operate or utilize a separator for a meaningful time period.

The Independent Producers proposed definition of a low pressure well that focused on the "three day" flowback period attempted to recognize this point. The dynamics of most vertical wells and energized wells are such that RECs or combustion by way of a separator is not feasible. The Independent Producers request that USEPA address this issue in their final rule to acknowledge that not every well will have the three flowback stages clearly defined, and in certain instances, the separation flowback stage is so short that RECs are not feasible or required, *i.e.*, that a well can essentially go from the initial flowback state to the production stage. There is a subjective element to this evaluation, which USEPA has acknowledged, so the final rule should not prevent those drilling low pressure wells from continuing their operations. As noted before in various comments, the economic incentive to undertake RECs exists. USEPA's proposed low pressure well definition forces controls on a segment of the industry that have no or minimal beneficial impact on the environment while imposing significant additional costs that will make drilling and operating such wells uneconomical. The Independent Producers request that the definition of a low pressure well be revised as suggested above or that USEPA acknowledge the separation flowback stage can be so short in duration that RECs are not necessary.

In addition to the comments above, the Independent Producers support and incorporate by reference the comments file by the American Exploration and Production Council ("AXPC")[7] on this proposed rule.

---

[6] Oil and Natural Gas Sector: Reconsideration of Additional Provisions of New Source Performance Standards; Proposed Rule, 79 Fed. Reg. 41752 (July 17, 2014).
[7] AXPC is a national trade association representing 34 of the largest United States independent natural gas and crude oil exploration and production companies.

If the USEPA has any questions or concerns regarding the comments, please do not hesitate to contact me.

Sincerely,

James D. Elliott

cc: Bruce Moore
Amy Branning
Lee Fuller, IPAA Vice President of Government Relations
Charlie Burd, IOGA-WV Executive Director
Andrew V. McNeill, KOGA Executive Director
Lou D'Amico, PIOGA Executive Director
Thomas A. Stewart, OOGA Executive Vice President
Matt Stone INOGA President
Brad Richards, IOGA Executive Vice President
Greg Kozera, VOGA President

ATTACHMENT 1

Lessons Learned
from Natural Gas STAR Partners

Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells

Executive Summary

In recent years, the natural gas industry has developed more technologically challenging unconventional gas reserves such as tight sands, shale and coalbed methane. Completion of new wells and re-working (workover) of existing wells in these tight formations typically involve hydraulic fracturing of the reservoir to increase well productivity. Industry reports that hydraulic fracturing is beginning to be performed in some conventional gas reservoirs as well. Removing the water and excess proppant (generally sand) during completion and well clean-up may result in significant releases of natural gas and therefore methane emissions to the atmosphere. The *U.S. Inventory of Greenhouse Gas Emissions and Sinks 1990 - 2009* estimates that 68 billion cubic feet (Bcf) of methane are vented or flared annually from unconventional completions and workovers.

Reduced emissions completions (RECs) – also known as reduced flaring completions or green completions – is a term used to describe an alternate practice that captures gas produced during well completions and well workovers following hydraulic fracturing. Portable equipment is brought on site to separate the gas from the solids and liquids produced during the high-rate flowback, and produce gas that can be delivered into the sales pipeline. RECs help to reduce methane, VOC, and HAP emissions during well cleanup and can eliminate or significantly reduce the need for flaring.

RECs have become a popular practice among Natural Gas STAR production partners. A total of thirteen different partners have reported performing reduced emissions completions in their operations. RECs have become a major source of methane emission reductions since 2000. Between 2000 and 2009 emissions reductions from RECs (as reported to Natural Gas STAR) have increased from 200 MMcf (million cubic feet) to over 218,000 MMcf. Capturing an additional 218,000 MMcf represents additional revenue from natural gas sales of over $1.5 billion from 2000 to 2009 (assuming $7/Mcf gas prices).

Technology Background

High demand and higher prices for natural gas in the U.S. have resulted in increased drilling of new wells in more expensive and more technologically challenging unconventional gas reservoirs, including those in low porosity (tight) formations. These same high demands and

Economic and Environmental Benefits

Method for Reducing Natural Gas Losses	Volume of Natural Gas Savings (Mcf)	Value of Natural Gas Savings ($)			Additional Savings ($)	Implemen-tation Cost ($)	Other Costs ($)	Payback (Months)		
		$3 per Mcf	$5 per Mcf	$7 per Mcf				$3 per Mcf	$5 per Mcf	$7 per Mcf
Purchased REC Equipment Annual Program	270,000 per year	$810,000 per year	$1,350,000 per year	$1,890,000 per year	$175,000 per year	$500,000	$121,250 per year	6	4	3
Incremental REC Contracted Service	10,800 per completion	$32,400 per completion	$54,000 per completion	$75,600 per completion	$6,930 per completion	$32,400	$600 per completion	Imme-diate	Imme-diate	Imme-diate

General Assumptions:
[a] Assuming 9 days per completion, 1,200 Mcf gas savings per day per well, 11 barrels of condensate recovered per day per well, and cost of $3,600 per well per day for contracted services.
[b] Assuming $70 per barrel of condensate.
[c] Based on an annual REC program of 25 completions per year.

prices also justify extra efforts to stimulate production from existing wells in tight reservoirs where the down-hole pressure and gas production rates have declined, a process known as well workovers or well-reworking. In both cases, completions of new wells in tight formations and workovers of existing wells, one technique for improving gas production is to fracture the reservoir rock with very high pressure water containing a proppant (generally sand) that keeps the fractures "propped open" after water pressure is reduced. Depending on the depth of the well, this process is carried out in several stages, usually completing one 200- to 250-foot zone per stage.

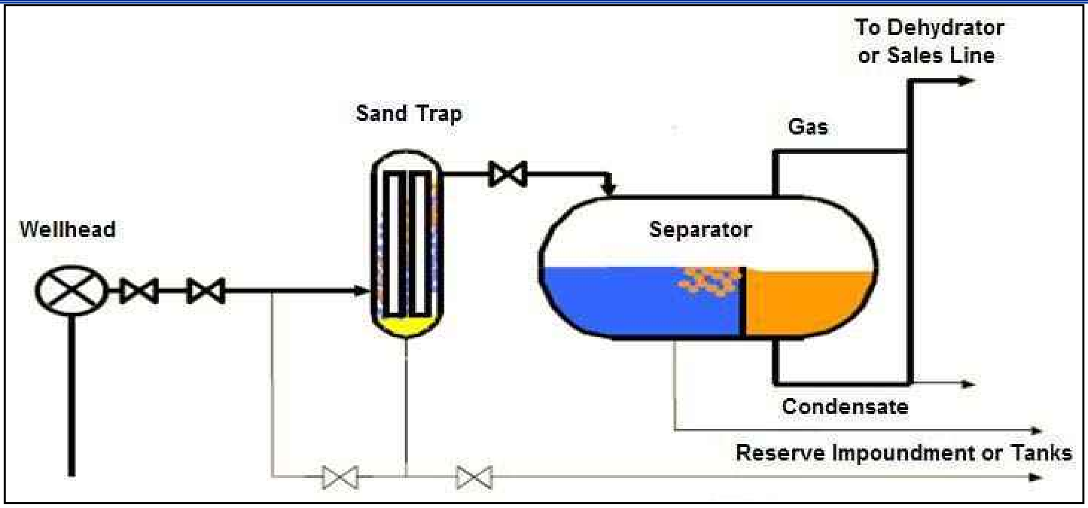
These new and "workover" wells are completed by producing the fluids at a high rate to lift the excess sand to the surface and clear the well bore and formation to increase gas flow. Typically, the gas/liquid separator installed for normal well flow is not designed for these high liquid flow rates and three-phase (gas, liquid and sand) flow. Therefore, a common practice for this initial well completion step has been to produce the well to a pit or tanks where water, hydrocarbon liquids and sand are captured and slugs of gas vented to the atmosphere or flared. Completions can take anywhere from one day to several weeks during which time a substantial amount of gas may be released to the atmosphere or flared. Testing of production levels occurs during the well completion process, and it may be necessary to repeat the fracture process to achieve desired production levels from a particular well.

Natural gas lost during well completion and testing can be as much as 25 million cubic feet (MMcf) per well depending on well production rates, the number of zones completed, and the amount of time it takes to complete each zone. This gas is generally unprocessed and may contain volatile organic compounds (VOCs) and hazardous air pollutants (HAPs) along with methane. Flaring gas may eliminate most methane, VOC and HAP emissions, but open flaring is not always a preferred option when the well is located near residential areas or where there is a high risk of grass or forest fires. Moreover, flaring may release additional carbon dioxide and other criteria pollutants (SOx, NOx, PM and CO) to the atmosphere.

Natural Gas STAR partners have reported performing RECs that recover much of the gas that is normally vented or flared during the completion process. This involves installing portable equipment that is specially designed and sized for the initial high rate of water, sand, and gas flowback during well completion. The objective is to capture and deliver gas to the sales line rather than venting or flaring this gas.

Sand traps are used to remove the finer solids present in the production stream. Plug catchers are used to remove any large solids such as drill cuttings that could damage the other separation equipment. The piping configuration to the sand traps is critical as the abrasion from high velocity water and sand can erode a hole in steel pipe elbows, creating a "washout" with water, sand,

Exhibit 1: Reduced Emissions Completion Equipment Layout



Adapted from BP.

hydrocarbon liquids and gas in an uncontrolled flow to the pad. Depending on the gas gathering system, it may be necessary to dehydrate (remove water from) the produced gas before it enters the sales pipeline. The gas may be routed to the permanent glycol unit for dehydration or a portable desiccant/glycol dehydrator used for dehydration during the completion process.

Free water and condensate are removed from the gas in a three phase separator. Condensate (liquid hydrocarbons) collected during the completion process may be sold for additional revenue. Temporary piping may be used to connect the well to the REC skid and gathering system if the permanent piping is not yet in place. Exhibit 1 shows a typical layout of temporary REC portable equipment, and Exhibit 2 explains some alternate, emerging, and/or experimental procedures for a well completion and REC.

Exhibit 2: Alternate Completion Procedures

<u>Energized Fracturing</u>
Based on Natural Gas STAR partner experiences, RECs can also be performed in combination with energized fracturing, wherein inert gas such as CO_2 or nitrogen is mixed with the frac water under high pressure to aid in the process of fracturing the formation. The process is generally the same with the additional consideration of the composition of the flowback gas. The percent of inert gases in the flowback gas is, at first, unsuitable for delivery into the sales line. As the fraction of inerts decreases, the gas can be recovered economically. A portable membrane acid gas separation unit can further increase the amount of methane recovered for sales after a CO_2 energized fracture.

<u>Compression</u>
Two compressor applications during an REC have been identified or explored by Natural Gas STAR partners.

1) Gas Lift. In low pressure (i.e. low energy) reservoirs RECs are often carried out with the aid of compressors for gas lift. Gas lift is accomplished by withdrawing gas from the sales line, boosting its pressure, and routing it down the well casing to push the frac fluids up the tubing. The increased pressure facilitates flow into the separator and then the sales line where the lift gas becomes part of the normal flowback that can be recovered during an REC.

2) Boost to Sales Line. When the gas recovered in the REC separator is lower pressure than the sales line, some companies are experimenting with a compressor to boost flowback gas into the sales line. This technique is experimental because of the difficulty operating a compressor on widely fluctuating flowback rate. Coal bed methane well completion is an example where additional compression might be required.

The equipment used during RECs is only necessary for the time it takes to complete the well; therefore, it is essential that all the equipment can be readily transported from site to site to be used in a number of well completions. A truck mounted skid, as shown in Exhibit 3, is ideal for transporting the equipment between sites. In a large basin that has a high level of drilling activity it may be economic for a gas producer to build its own REC skid. Most producers may prefer contracting a third party service to perform completions.

When using a third party to perform RECs, it is most cost effective to integrate the scheduling of completions with the annual drilling program. Well completion time is another factor to consider for scheduling a contractor for RECs. Some well completions, such as coal bed methane, may take less than a day. On the other hand, completing wells which fracture various zones, such as shale gas wells, may take several weeks to complete. For most wells, it takes about 3 to 10 days to perform a well completion following a hydraulic fracture, based on partner experiences.

Exhibit 3: Truck Mounted Reduced Emissions Completion Equipment

Source: Weatherford

Economic and Environmental Benefits

- ★ Gas recovered for sales
- ★ Condensate recovered for sales
- ★ Reduced methane emissions

- ★ Reduced loss of a valuable hydrocarbon resource
- ★ Reduced emissions of criteria and hazardous air pollutants

Emissions from well completions can contribute to a number of environmental problems. Direct venting of VOCs can contribute to local air pollution, HAPs are deemed harmful to human health, and methane is a powerful greenhouse gas that contributes to climate change. Where it is safe, flaring is preferred to direct venting because methane, VOCs, and HAPs are combusted, lowering pollution levels and reducing global warming potential (GWP) of the emissions as CO_2 from combustion has a lower GWP than methane. RECs allow for recovery of gas rather than venting or flaring and therefore reduce the environmental impact of well completion and workover activities.

RECs bring economic benefits as well as environmental benefits. The incremental costs associated with the rental of third party equipment for performing RECs can be offset by the additional revenue from the sale of gas and condensate. As this technology is being perfected and equipment becomes commonplace, the revenues in gas and condensate sales often exceed the incremental costs.

Decision Process

Step 1: Evaluate candidate wells for Reduced Emissions Completions.

When setting up an annual RECs program it is important to examine the characteristics of the wells that are going to be brought online in the coming year. Wells in conventional reservoirs that do not require a reservoir fracture (frac job) and will produce readily without stimulation can be cleared of drilling fluids and connected to a production line in a relatively short period of time with minimal gas venting or flaring, and therefore usually do not economically justify REC equipment. Wells that undergo energized fracture using inert gases require special considerations because the initial produced gas captured by the REC equipment would not meet pipeline specifications due to the inert gas content. However, as the amount of inerts decreases, the quality of the gas will likely meet pipeline specifications. In the case of CO_2 energized fracks, the use of portable acid gas removal membrane separators will improve gas quality and make it possible to direct gas to the pipeline (see Partner Experiences section for more information).

Decision Process
Step 1: Evaluate candidate wells
Step 2: Determine costs
Step 3: Estimate savings
Step 4: Evaluate economics

State and Local Regulations
The States of Wyoming and Colorado have regulations requiring the implementation of "flareless completions". Operators of new wells in this region are required to complete wells without flaring or venting. These completions have reduced flaring by 70 to 90 percent.

For more information, visit:
http://deq.state.wy.us
http://www.cdphe.state.co.us

Exploratory and delineation wells in areas that do not yet have sales pipelines in close proximity to the wells are not candidates for RECs as the infrastructure is not in place to receive the recovered gas. In depleted or low pressure fields with low energy reservoirs, implementing a RECs program would most likely require the addition of compression to overcome the sales line pressures–an approach that is still under development and may add significant cost to implementation.

Wells that require hydraulic fracturing to stimulate or enhance gas production may need a lengthy completion, and therefore are good candidates for RECs. Lengthy completions mean that a significant amount of gas may be vented or flared that could potentially be recovered and sold for additional revenue to justify the additional cost of a REC. If newly drilled wells are in close proximity, they could share the REC equipment to minimize transport, set-up, and equipment rental costs.

Selecting a Basis for Costs and Savings

- ★ Estimate the number of producing gas wells that will be drilled in the next year
- ★ Evaluate well depth and reservoir characteristics
- ★ Determine whether additional equipment is necessary to bring recovered gas up to pipeline specifications
- ★ Estimate time needed for each completion

Step 2: Determine the costs of a REC program.

Most Natural Gas STAR partners report using third party contractors to perform RECs on wells within their producing fields. It should be noted that third party contractors are also often used to perform traditional well completions. Therefore, the economics presented deal with incremental costs to carry out RECs versus traditional completions.

Generally, the third party contractor will charge a commissioning fee for transporting and setting up the equipment for each well completion within the operator's producing field. Some RECs vendors have their equipment mounted on a single trailer while others lay down individual skids that must be connected with temporary piping at each site. The incremental cost associated with transportation between well sites in the operator's field and connection of the REC equipment within the normal flowback piping from the wellhead to an impoundment or tank is generally around $600/completion.

In addition to the commissioning fee, there is a daily cost for equipment rental and labor to perform each REC. As mentioned above, when evaluating the costs of well completions, it is important to consider the incremental cost of a REC over a traditional completion rather than focusing on the total cost. REC vendors and Natural Gas STAR partners have reported the incremental cost of equipment rental and labor to recover natural gas during completion ranging from $700 to $6,500/day over a traditional completion. Equipment costs associated with RECs will vary from well to well. High production rates may require larger equipment to perform the REC and will increase costs. If permanent equipment such as a glycol dehydrator is already installed at the well site, REC costs may be reduced as this equipment can be used rather than bringing a portable dehydrator on-site, assuming the flow-back rate does not exceed the capacity of the equipment. Some operators report installing permanent equipment that can be used in the RECs as part of normal well completion operations, such as oversized three-phase separators, further reducing incremental REC costs. Well completions usually take between 1 to 30 days to clean out the well bore, complete well testing, and tie into the permanent sales line. Wells requiring multiple fractures of a tight formation to stimulate gas flow may require additional completion time. Exhibit 4 shows the typical costs associated with undertaking a REC at a single well.

Exhibit 4: Typical Costs for RECs

One-time Transportation and Incremental Set-up Costs	Incremental REC Equipment Rental and Labor Costs	Well Clean-up Time
$600 per well	$700 to $6,500 per day	3 to 10 days

For low energy reservoirs, gas from the sales line may be routed down the well casing to create artificial gas lift, as mentioned in Exhibit 2. Depending on the depth of the well, a different quantity of gas will be required to lift the fluids and clean out the well. Using average reservoir depths for major U.S. basins and engineering calculations, Exhibit 5 shows various estimates of the volume of gas required to lift fluids for different well depths.

A REC annual program may consist of completing 25 wells/year within a producer's operating region. Exhibit 6 shows a hypothetical example of REC program costs based on information provided by partner companies.

Exhibit 5: Sizing and Fuel Consumption for Booster Compressor

Well Depth (ft)	Pressure Required to Lift Fluids (psig)	Gas Required to Lift Fluids (Mcf)[a]	Compressor Size (horsepower)[a]	Compressor Fuel Consumption (Mcf/hr)[a]
3,000	1,319 + Sales line pressure	195 to 310	195 to 780	2 to 7
5,000	2,323 + Sales line pressure	315 to 430	400 to 1,500	3 to 13
8,000	3,716 + Sales line pressure	495 to 610	765 to 2,800	7 to 24
10,000	4,645 + Sales line pressure	615 to 730	1,040 to 3,900	9 to 33

[a] Based on sales line pressures between 100 to 1,000 psig.

Exhibit 6: Hypothetical Example Cost Calculation of a 25 Well Annual REC Program

Given

W = Number of completions per year
D = Well depth in feet (ft)
P_s = Sales line pressure in pounds per square inch gauge (psig)
T_s = Time required for transportation and set-up (days/well)
T_c = Time required for well clean-up (days/well)
O = Operating time for compressor to lift fluids (hr/well)
F = Compressor fuel consumption rate (Mcf/hr)
G = Gas from pipeline routed to casing to lift fluids (Mcf/well), typically used on low energy reservoirs
C_s = Transportation and set-up cost ($/well)
C_e = Equipment and labor cost ($/day)
P_g = Sales line gas price ($/Mcf)

W = 25 wells/yr
D = 8000 ft
P_s = 100 psig
T_s = 1 day/well
T_c = 9 days/well
O = 24 hr/well
F = 10 Mcf/hr
G = 500 Mcf/well (See Exhibit 5)
C_s = $600/well
C_e = $2,000/day
P_g = $7/Mcf

Calculate Total Transportation and Set-up Cost, C_{TS}

$C_{TS} = W * C_s$

C_{TS} = 25 wells/yr * $600/well
C_{TS} = $15,000/yr

Calculate Total Equipment Rental and Labor Cost, C_{EL}

$C_{EL} = W * (T_s + T_c) * C_e$

C_{EL} = 25 wells/yr * (1 day/well + 9 days/well) * $2,000/day
C_{EL} = $500,000/yr

Calculate Other Costs, C_O

$C_O = W * [(O * F) + G] * P_g$

C_O = 25 wells/yr * [(24 hr/well * 10 Mcf/hr) + 500 Mcf/well] * $7/Mcf
C_O = $129,500/yr

Total Annual REC Program Cost, C_T

$C_T = C_{TS} + C_{EL} + C_O$
C_T = $15,000/yr + $500,000/yr + $129,500/yr
C_T = $644,500/yr

Step 3: Estimate Savings from RECs.

Gas recovered from RECs can vary widely because the amount of gas recovered depends on a number of variables such as reservoir pressure, production rate, amount of fluids lifted, and total completion time. Exhibit 7 shows the range of recovered gas and condensate reported by Natural Gas STAR partners. Partners also have reported that not all the gas that is produced during well completions may be captured for sales. Fluids from high pressure wells are often routed directly to the frac tank in the initial stages of completion as the fluids are often being produced at a rate that is too high for the REC equipment. Where inert gas is used to energize the frac, the initial gas production may have to be flared until the gas meets pipeline specifications. Alternatively, a portable acid gas membrane separator may be used to recover methane rich gas from CO_2. As the flow rate of fluids drops and gas is encountered, backflow is then switched over to the REC equipment so that the gas may be captured. Gas compressed from the sales line to lift fluids (by artificial gas lift) will also be recovered in addition to the gas produced from the reservoir. The volume of gas needed to lift fluids can be estimated based on the well depth and sales line pressure. Gas saved during RECs can be translated directly into methane emissions reductions based on the methane content of the produced gas.

In addition to gas savings, valuable condensate may also be recovered from the REC three-phase separator. The amount of condensate that can be recovered during a REC is dependent on the reservoir conditions and fluid compositions. Condensate may also be lost if fluids are produced directly to the frac tank before switching to the REC equipment.

Exhibit 7: Ranges of Gas and Condensate Savings

Produced Gas Savings (Mcf/day/well)	Gas-Lift Savings (Mcf/well)	Condensate Savings (bbl/day/well)
500 to 2,000	See Exhibit 5	Zero to several hundred

Exhibit 8 shows typical values of gas and condensate savings during the REC process.

Step 4: Evaluate REC economics.

The example application of an REC program to 25 wells within a producing field can yield a total theoretical revenue of $2,152,500 based on the assumptions listed above from the sale of natural gas and condensate. Equipment rental, labor, and other costs associated with implementing this program are estimated to be $644,500 (see Exhibit 6) resulting in an annual theoretical profit of $1,508,000. To maintain a profitable REC program, it is important to move efficiently from well to well within a producing field so that there is little down time when paying for equipment rental and labor. Other factors that affect the profitability of an REC program include the amount of condensate recovery and sales price, the need for additional compressors, the amount of gas recovered, and gas sales price.

Exhibit 9 shows a five year cash flow projection for carrying out a 25 well per year REC program. In this example, the equipment necessary to perform RECs has been purchased by the operator rather than using a third party contractor to perform the service. The capital cost of a simple REC set-up without a portable compressor has been reported by British Petroleum (BP) to be $500,000.

Producers with high levels of localized drilling and workover activity may benefit from constructing and operating their own REC equipment. As illustrated above, even though large capital outlay is required to construct a REC skid, a high rate of return can be achieved if the equipment is in continuous use. If the operator is unable to keep the equipment busy on their own wells, they may

Nelson Price Indexes

In order to account for inflation in equipment and operating & maintenance costs, Nelson-Farrar Quarterly Cost Indexes (available in the first issue of each quarter in the *Oil and Gas Journal*) are used to update costs in the Lessons Learned documents.

The "Refinery Operation Index" is used to revise operating costs while the "Machinery: Oilfield Itemized Refining Cost Index" is used to update equipment costs.

To use these indexes in the future, simply look up the most current Nelson-Farrar index number, divide by the February 2006 Nelson-Farrar index number, and, finally multiply by the appropriate costs in the Lessons Learned.

Exhibit 8: Savings of a 25 Well Annual REC Program

Given

W = Number of completions per year
D = Well depth in feet (ft)
P_s = Sales line pressure in pounds per square inch gage (psig)
S_p = Produced gas savings (Mcf/day)
T_c = Time recovered gas flows to sales line in days (days/well)
S_c = Condensate savings (bbl/well)
G = Gas used to lift fluids (Mcf/well), typically used on low energy reservoirs
P_g = Sales line gas price ($/Mcf)
P_l = Natural gas liquids price ($/bbl)

W = 25 wells/yr
D = 8000 ft
P_s = 100 psig
S_p = 1,200 Mcf/day
T_c = 9 days/well
S_c = 100 bbl/well
G = 500 Mcf/well (See Exhibit 5)
P_g = $7/Mcf
P_l = $70/bbl

Calculate Produced Gas Savings

$S_{PG} = W * (S_p * T_c) * P_g$

S_{PG} = 25 wells/yr * (1,200 Mcf/day * 9 days/well) * $7/Mcf
S_{PG} = $1,890,000/yr

Calculate Other Savings

$S_O = W * [(G * P_g) + (S_c * P_l)]$

S_O = 25 wells/yr * [(500 Mcf/well * $7/Mcf) + (100 bbl/well * $70/bbl)]
S_O = $262,500/yr

Total Savings, S_T

$S_T = S_{PG} + S_O$
S_T = $1,890,000/yr + $262,500/yr
S_T = $2,152,500/yr

contract it out to other operators to maximize usage of the equipment.

When assessing REC economics, the gas price may influence the decision making process; therefore, it is important to examine the economics of undertaking a REC program as natural gas prices change. Exhibit 10 shows an economic analysis of performing the 25 well per year REC program in Exhibit 8 at different gas prices.

Exhibit 9: Economics for Hypothetical 25 Well Annual REC Program with Purchased Equipment

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Volume of Natural Gas Savings (Mcf/yr)[a]		270,000	270,000	270,000	270,000	270,000
Value of Natural Gas Savings ($/year)[a]		1,890,000	1,890,000	1,890,000	1,890,000	1,890,000
Additional Savings ($/yr)[a]		175,000	175,000	175,000	175,000	175,000
Set-up Costs ($/yr)[b]		(15,000)	(15,000)	(15,000)	(15,000)	(15,000)
Equipment Costs ($)[b]	(500,000)					
Labor Costs ($/yr)[c]		(106,250)	(106,250)	(106,250)	(106,250)	(106,250)
Net Annual Cash Flow ($)	**(500,000)**	**1,943,750**	**1,943,750**	**1,943,750**	**1,943,750**	**1,943,750**

Internal Rate of Return = 389%
NPV (Net Present Value)[d] = $6,243,947
Payback Period = 3 months

[a] See Exhibit 8.
[b] See Exhibit 6.
[c] Labor costs for purchased REC equipment estimated as 50% of Equipment Rental and Labor costs in Exhibit 3.
[d] Net present value based on 10% discount rate over five years.

Exhibit 10: Gas Price Impact on Economic Analysis of Hypothetical 25 Well Annual REC Program with Purchased Equipment

	Gas Price				
	$3/Mcf	**$5/Mcf**	**$7/Mcf**	**$8/Mcf**	**$10/Mcf**
Total Savings	$985,000	$1,525,000	$2,065,000	$2,335,000	$2,875,000
Payback (months)	7	5	4	3	3
IRR	172%	280%	389%	443%	551%
NPV (i = 10%)	$2,522,084	$4,383,015	$6,243,947	$7,174,413	$9,035,345

Partner Experience

This section highlights specific experiences reported by Natural Gas STAR partners.

BP Experience in Green River Basin

- ★ Implemented RECs in the Green River Basin of Wyoming
- ★ RECs performed on 106 wells, which consisted of high and low pressure wells
- ★ Average 3,300 Mcf of natural gas sold versus vented per well
  - – Well pressure will vary from reservoir to reservoir
  - – Reductions will vary for each particular region
  - – Conservative net value of gas saved is $20,000 per well
- ★ Natural gas emission reductions of 350,000 Mcf in 2002
- ★ Total of 6,700 barrels of condensate recovered per year total for 106 wells
- ★ Through the end of 2005, this partner reports a total of 4.17 Bcf of gas and more than 53,000 barrels of condensate recovered and sold rather than flared. This is a combination of activities in the Wamsutter and Jonah/Pinedale fields.

Noble Experience in Ellis County, Oklahoma

- ★ Implemented RECs on 10 wells using energized fracturing.
- ★ Employed membrane separation in which the permeate was a CO_2 rich stream that was vented and the residue was primarily hydrocarbons which were recovered.
- ★ Total cost of $325,000.
- ★ Total gas savings of approximately 175 MMcf.
- ★ Estimated net profits to be $340,000
- ★ For more information, see the Partner Profile Article in the Spring 2011 Natural Gas STAR Partner Update available at: http://epa.gov/gasstar/newsroom/partnerupdatespring2011.html

Partner Company A

- ★ Implemented RECs in the Fort Worth Basin of Texas
- ★ RECs performed on 30 wells, with an incremental cost of $8,700 per well
- ★ Average 11,900 Mcf of natural gas sold versus vented per well
  - – Natural gas flow and sales occur 9 days out of 2 to 3 weeks of well completion
  - – Low pressure gas sent to gas plant
  - – Conservative net value of gas saved is $50,000 per well
- ★ Expects total emission reduction of 1.5 to 2 Bcf in 2005 for 30 wells

Lessons Learned

- ★ Incremental costs of recovering natural gas and condensate during well completions following hydraulic fracturing result from the use of additional equipment such as sand traps, separators, portable compressors, membrane acid gas removal units and desiccant dehydrators that are designed for high rate flowback.
- ★ During the hydraulic fracture completion process, sands, liquids, and gases produced from the well are separated and collected individually. Natural gas and gas liquids captured during the completion may be sold for additional revenue.
- ★ Implementing a REC program will reduce flaring which may be a particular advantage where open flaring is undesirable (populated areas) or unsafe (risk of fire).
- ★ Wells that do not require hydraulic fracturing are not good candidates for reduced emissions completions. Methane emissions reductions achieved through performing RECs may be reported to the Natural Gas STAR Program unless RECs are required by law (as in the Jonah-Pinedale area in WY).

References

Alberts, Jerry. Williams Company. Personal contact.

American Petroleum Institute. Basic Petroleum Data Book, Volume XXV, Number 1. February 2005.

Bylin, Carey. U.S. EPA. Gas STAR Program Manager

Department of Energy. GASIS, Gas Information System. Release 2 – June 1999.

Fernandez, Roger. U.S. EPA. Gas STAR Program Manager

McAllister, E.W., Pipeline Rules of Thumb Handbook, 4th Edition, 1998.

Middleman, Stanley. An Introduction to Fluid Dynamics, Principles of Analysis and Design. 1998.

Perry, Robert H., Don W. Green. Perry's Chemical Engineers Handbook, 7th Edition. 1997.

Pontiff, Mike. Newfield Exploration Company. Personal contact.

Process Associates of America. "Reciprocating Compressor Sizing." Available on the web at: http://www.processassociates.com/process/rotating/recip_s.htm.

Smith, Reid. BP PLC. Personal contact.

Smuin, Bobby. BRECO, Incorporated. Personal contact.

U.S. EPA. "The Natural Gas STAR Partner Update – Spring 2004." Available on the web at: http://www.epa.gov/gasstar/pdf/partnerupdate.pdf

Wadas, Janelle. Noble Energy Inc. 2010 Annual Implementation Workshop Presentation titled "Reducing Vented Flowback Emissions from CO2 Fractured Gas Wells Using Membrane Technology". Available on the web at: http://epa.gov/gasstar/documents/workshops/2010-annual-conf/01wadas.pdf

Waltzer, Suzanne. U.S. EPA. Gas STAR Program Manager

United States
Environmental Protection Agency
Air and Radiation (6202J)
1200 Pennsylvania Ave., NW
Washington, DC 20460

2011

EPA provides the suggested methane emissions estimating methods contained in this document as a tool to develop basic methane emissions estimates only. As regulatory reporting demands a higher-level of accuracy, the methane emission estimating methods and terminology contained in this document may not conform to the Greenhouse Gas Reporting Rule, 40 CFR Part 98, Subpart W methods or those in other EPA regulations.

May, 28, 21013

The Honorable Bob Perciasepe, Acting Administrator
U.S. Environmental Protection Agency
EPA West (Air Docket), Room 3334
1301 Constitution Ave., NW
Washington, DC 20004

Attention: Docket ID Number EPA-HQ-OAR-2010-0505
Submitted via email to *a-and-r-docket@epa.gov*

RE: Comments of the Independent Petroleum Association of America on "Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards," 78 Fed.Reg. 22126 (Apr. 12, 2013). Docket ID No. EPA-HQ-OAR-2010-0505

Dear Acting Administrator Perciasepe:

The Independent Petroleum Association of America ("IPAA") appreciates the opportunity to provide comments on the United States Environmental Protection Agency's ("EPA") rulemaking entitled "Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards," 78 Fed. Reg. 22,126 (April 12, 2013). 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 be the most significantly affected by these proposed regulatory actions. Independent producers develop 95 percent of domestic oil and gas wells, produce 68 percent of domestic oil and produce 82 percent of domestic 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.

IPAA believes the majority of the proposed revisions are beneficial to the industry while still protective of the environment. IPAA looks forward to working with EPA to further improve the rule. IPAA also appreciates EPA's willingness to expedite this rulemaking in light of the pending October 15, 2013 compliance deadline for the storage vessel requirements under 40 C.F.R. Part 60 Subpart OOOO. IPAA believes collaboration between the agency and the regulated community will result in workable regulations that are both cost-effective and protective of the environment.

As further discussed later in these comments, IPAA generally supports the following proposed amendments to the existing requirements for storage vessels:

- IPAA supports breaking down storage vessel affected facilities into two categories (i.e., "Group 1" and "Group 2" tanks) to help reduce the demand for control devices and service providers, as well as the proposed extension of the compliance deadline for implementing controls to April 15, 2014. The potential for a shortage of equipment and service providers—even with the extended deadline—remains real for many of the smaller independent producers with less leverage and buying power.
- IPAA strongly supports the proposed streamlined provisions related to continuous compliance demonstration and monitoring requirements during the reconsideration period. IPAA requests that the streamlined provisions be proposed for adoption as the final compliance and monitoring requirements in the anticipated rulemaking to address additional reconsideration issues (expected proposal in December 2013).
- IPAA supports the concept of an alternative mass-based limit for uncontrolled emissions and the ability to remove controls if emissions are demonstrated to fall below an established threshold for a set period of time. Although IPAA appreciates that EPA believes it is inappropriate for the alternative mass-based limit to be the same as the applicability threshold, EPA has failed to provide a reasoned or rational basis for its position. EPA initially justified controls on storage vessels as cost effective at 6 tons per year ("TPY") – not 4 TPY. IPAA believes the alternative mass-based limit should be 6 TPY.
- IPAA supports extending the time period for the submittal of annual reports and compliance certifications from 30 days to 90 days after the end of the given compliance period.
- IPAA supports EPA's effort to align the test protocols for combustion control devices for the NSPS with those found in the applicable National Emission Standards for Hazardous Air Pollutants and the provisions which provide for manufacturer testing provisions that allow for certification of certain specific devices.
- IPAA supports the clarification of the definitions of "storage vessel" and "storage vessel affected facility."

In addition to generally supporting the proposed amendments discussed above, IPAA provides the following comments and suggestions that it believes will further improve the final provisions of the rule.

1. As currently proposed, Group 1 storage vessels are required to comply with certain additional provisions if there is an "event that could reasonably be expected to increase VOC emissions . . . ." 40 C.F.R. § 60.5395(b). The subsection cites the following four "examples" of events, indicating the list is not exhaustive: (i) routing an additional well to the storage vessel that was not previously routed to the vessel, (ii) conducting fracturing on a well routed to the storage vessel, (iii) conducting refracturing on a well routed to the storage vessel, and (iv) any other event that could increase the VOC emissions from the storage vessel affected facility. *Id.* § 60.5395(b)(2)(i)-(iv). IPAA believes the definition of "event" should be limited to the first three examples, as the fourth "example" is so broad and subjective as to provide no clarification whatsoever. To the extent that EPA is unwilling to limit the examples of qualifying "events," the fourth example should be revised to read "any other event that could **reasonably be expected to** increase the VOC emissions from the storage vessel affected facility."

2. As currently proposed, owners and operators of Group 2 storage vessels must determine their VOC emissions by April 15, 2014 or 30 days after startup, whichever is later. *Id.* § 60.5395(c)(1) and (2). If VOC emissions are projected to be equal or greater than 6 TPY, then controls must be installed by April 15, 2014 or 60 days after startup, whichever is later. *Id.* § 60.5395(d). These time periods are simply too short. At a minimum, **90 days** is necessary to conduct the required emissions calculation and install controls. The first 30 days of production normally are not representative of stabilized production from a well, and are subject to variation that could result in the overestimation **or** underestimation of the emissions from storage vessels associated with that well. Thus, at least 45 days is needed to evaluate and accurately calculate projected annual emissions from a storage vessel. Another 45 days—again, at a minimum—would be needed to engage a contractor and install the necessary controls. Providing a total of 90 days to make the initial emissions determination **and** install any necessary controls will ensure a more reliable emissions estimate and afford the regulated community sufficient time to contract for the testing/modeling of emissions and installation of controls. Accordingly, IPAA recommends that EPA extend this compliance period to 90 days.

3. If EPA is unwilling to provide 90 days for operators to conduct their emissions determinations and install necessary controls as requested in Comment No. 2 above, IPAA believes it is appropriate to consider differentiating between storage vessels located at new facilities (or at existing facilities not subject to air quality permitting) versus storage vessels at existing, currently permitted facilities. The primary methodology for projecting emissions from storage vessels involves hiring an outside contractor to visit the site, sample the condensate/liquid, conduct laboratory analysis to generate the condensate characteristics, and then calculate emissions based upon the throughput of the vessel. The logistics of retaining and then scheduling the contractor to perform this work takes time, and there will be instances that producers—especially independent producers—will not likely be able to comply with the 30-day emissions determination for reasons beyond their control (i.e., they could not get a service provider out to the storage vessel in time). Similar issues can arise with regard to the installation of emissions controls. Storage vessels at existing affected facilities with air quality permits within the same formation or drilling characteristics are more likely to have relevant emissions modeling associated with the condensate/liquid produced from the well(s). Consequently, projecting annual emissions should be less time-consuming for these facilities, although IPAA believes that a 60-day compliance period for facilities with existing emissions data on condensate/liquids is necessary to provide the flexibility needed to align contractors for installation of controls. The importance of this issue for independent producers cannot be overstated. The lack of access to or ability to timely contract with service providers will place many of the smaller independent producers at serious risk of noncompliance, through no fault of their own.

4. If EPA is unwilling to adopt a permanent distinction between storage vessels at new and existing affected facilities as advocated in Comment No. 3 above, IPAA suggests that EPA institute an extended compliance period for vessels at new facilities for a period of two years. This will reduce the likelihood that independent producers will be exposed to enforcement due to the lack of available equipment and service providers, while continuing

to ensure that emissions reductions occur in a timely fashion. IPAA encourages EPA to strike an appropriate balance between achieving emissions reductions and the practical realities associated with limited supply of and increased demand for equipment and service providers. Unnecessarily condensed timeframes will have limited benefit to the environment, but will create undue hardship for a segment of the industry that provides a significant portion of the natural gas produced in this country.

5. As indicated above, IPAA supports the proposal to adopt an alternative emission limit of 6 TPY for uncontrolled emissions, and the ability to remove controls if emissions are demonstrated to fall below that threshold for a period of time. As currently proposed, if uncontrolled emissions from the affected facility drop below 4 TPY for a period of 12 consecutive months, the emission controls can be removed. *Id.* § 60.5395(d)(2). If at some point after the 12 month period the emissions rise above an estimated 4 TPY, however, controls must be reinstalled. *Id.* IPAA suggests certain revisions to these provisions, which would provide the same degree of environmental protection while reducing the burden and cost of compliance. In the response to comments document associated with the final rule, EPA calculated the cost effectiveness of controls at the 6 TPY threshold to be approximately $3400 per ton. *Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 40 CFR Parts 60 and 63, Response to Public Comments on Proposed Rule August 23, 2011 (76 FR 52738)*, at 108-110. Commenters argued that even a TPY threshold above10 TPY would result in a prohibitively high cost effectiveness of over $5000 per ton. EPA did not dispute the commenters calculations, but merely stated that EPA felt their "different source of cost information" . . . "developed specifically for this industry . . . may be more accurate than the more generalized Control Cost Manual analysis." *Id*. Subsequent studies and reports have called into question EPA's emissions estimates associated with hydraulic fracturing. IPAA believes that EPA has failed to justify its proposed alternative mass emission limit of 4 TPY and that the alternative limit should be 6 TPY. Additionally, instead of requiring 12 months of data demonstrating uncontrolled emissions below 4 TPY, IPAA believes that six months of data demonstrating emissions below 6 TPY is sufficient. As EPA has acknowledged, emissions from the vast majority of wells continue to decline over time and seldom increase without some intervening event. Thus, six months of data below an annual emission rate of 6 TPY is more than sufficient to demonstrate that the well is in steady decline and VOC emissions will remain below the 6 TPY threshold. IPAA also suggests that the obligation to conduct monthly monitoring be discontinued after six months of data demonstrating VOC emissions below 4TPY, absent an intervening event as set forth in 40 C.F.R. § 60.5395(b)(2).

6. As discussed above in Comment No. 5, under the current proposal, controls on storage vessels would need to be reinstalled if VOC emissions increase above the 4 TPY threshold. IPAA suggests that the threshold for reinstalling controls should be the same as the 6 TPY applicability limit for storage vessels initially. EPA has not provided a reasonable basis for imposing a different applicability threshold for tanks that initially had controls on them versus "new" vessels that are evaluating applicability for the first time. For example, if an operator needs to install a storage vessel at a new well pad and has two identically sized vessels at his disposal for installation—a brand new tank that has never been "installed"

and a tank that became an affected facility because its annual emissions were at one point above 6 TPY and is no longer needed at an older well—the incentive will be to install a new storage vessel to take advantage of the higher 6 TPY threshold, despite the fact that there is absolutely no difference between the two units. The different thresholds lack a supportable basis from an environmental standpoint and create an incentive to waste resources and unnecessarily drive up costs to producers.

7. In addition to the practical limitations of basing annual emissions on the first 30 days of production, IPAA is concerned about the enforcement ramifications of inaccurately estimating annual emissions based on this period. Essentially every estimate of annual emissions will be based on projected throughput over the course of a year. Due to the inherent uncertainty in projecting the production of a given well, there should be provisions included in the regulations that provide reduced enforcement exposure if producers diligently monitor their throughput (and hence their emissions) and promptly report any errors discovered with regard to the annual emissions estimate. IPAA appreciates that EPA must create the proper incentive for operators to make every effort to estimate their annual emissions accurately at the outset. However, IPAA believes that EPA also should consider that, unlike many other industrial processes, predicting the production of a given well is not a precise science. IPAA recommends that EPA include in the final version of this rule—or propose to include in the second reconsideration rulemaking scheduled for December 13, 2013—provisions that provide operators reduced enforcement exposure if errors in annual production based emissions calculations are promptly reported (e.g., within 30 days) to EPA (or the implementing state/local authority) and appropriate controls are installed within an additional 30 days. Such notification would require an explanation of why the initial annual emissions estimate was incorrect. IPAA further understands EPA's concerns regarding establishing a precedent in terms of reduced enforcement exposure for those entities that fail to make accurate emissions estimates. Again, the lack of predictability in estimating emissions from a given well is unlike projecting emissions from operations in other industries and thus gives EPA a basis for differential treatment. EPA has acknowledged such uncertainty in the regulations associated with greenhouse gas reporting and made certain accommodations accordingly, e.g. 40 C.F.R. § 98.3 (h). IPAA would be pleased to meet with EPA to discuss potential regulations that provide the proper incentive for producers to provide emissions estimates predicted on best engineering judgment while making allowances for unforeseen circumstances which could result in errors in the initial emission estimate.

8. As indicated above, IPAA strongly supports the streamlined compliance monitoring provisions proposed to be instituted during reconsideration of issues raised in the various reconsideration petitions. The existing provisions in the current rule are unnecessary to ensure compliance and are extremely burdensome to the smaller independent operations. As proposed, the monthly inspections and obligations for prompt repairs can be accomplished with existing personnel and not significantly add to the cost of compliance while ensuring that the required emissions controls are operating properly. The reasons that EPA proposed to utilize the streamline provisions and the benefit to industry will not change when the reconsideration rulemakings come to a close. The justifications for the

streamlined provisions during the reconsideration period will continue to be valid and warrant continuation of the streamlined provisions after the reconsideration rulemaking.

9. One additional "global" revision to the rules that would greatly reduce the inspection and monitoring obligations is to allow for proof of inspection and monitoring to be kept onsite, at the relevant field office or to be made available upon request. Many affected vessels are located in extremely remote areas and protecting such records from exposure to the environment is difficult. Additionally some operators conduct inspections and monitor certain equipment electronically, and therefore do not always generate "paper copies" on location. IPAA appreciates the need to record and retain inspection and monitoring records, but dictating that hard copies be maintained onsite is not necessary and may not be the best or most feasible way to retain the important information. Providing the operators the requested flexibility would benefit industry without harming the environment or reduce EPA's ability to monitor compliance effectively.

In addition to the comments provided above, IPAA endorses the comments of AXPC and ANGA. As indicated initially, IPAA appreciates the opportunity to provide comments on the proposed rule and would be happy to have further discussion with the agency regarding the issues raised above. Please contact me or Matt Kellogg at 202.857.4722 or Jim Elliott at 202.361.8215 if you have any questions regarding these comments.

Sincerely,

Lee O. Fuller

Lee O. Fuller
Vice President of Government Relations
Independent Petroleum Association of America

Cc: Gina McCarthy
Peter Tsirigotis
Steve Page
Bruce Moore
David Cozzie

Submitted via email

November 30, 2011

Gina McCarthy
Assistant Administrator
U.S. Environmental Protection Agency
Office of Air and Radiation
Mail Code: 6101A
Washington, DC 20460

Re: Oil and Natural Gas Sector Consolidated Rulemaking,
Docket ID No. EPA-HQ-OAR-2010-0505

Dear Assistant Administrator McCarthy,

The Independent Petroleum Association of America submits these comments with respect to the United States Environmental Protection Agency's (EPA) Proposed Rules entitled "*Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews*", dated August 23, 2011 (76 FR 52738).

These comments are filed on behalf of the Independent Petroleum Association of America (IPAA), the International Association of Drilling Contractors (IADC), the International Association of Geophysical Contractors (IAGC), the National Stripper Well Association (NSWA), the Petroleum Equipment Suppliers 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
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 Alliance of Independent Producers
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 Independent Producers and Royalty Owners Association
Utah Petroleum Association
Virginia Oil and Gas Association
West Virginia Oil and Natural Gas Association
Western Energy Alliance

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 the most significantly affected by these proposed regulatory actions. Independent producers drill about 95 percent of American oil and natural gas wells, produce about 56 percent of American oil, and more than 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. In general, we also support the comments submitted separately by the American Petroleum Institute (API), the American Exploration and Production Council (AXPC) and America's Natural Gas Alliance (ANGA). However, in some instances we believe that the proposed regulations are in such significant need of reevaluation that the only recourse is reconsideration and reproposal of regulations.

This proposed rulemaking would modify the New Source Performance Standards (NSPS) 40 CFR Part 60 Subparts KKK and LLL, create a new Subpart OOOO, and modify Part 63 Subparts HH and HHH. These rules are being addressed together under the auspices of EPA's sector-based rulemaking for the oil and natural gas industry. Our comments will address two aspects of the proposal: the NSPS for natural gas well completions and the NSPS for crude oil and condensate storage facilities.

In developing NSPS, EPA must meet the following definition:

> The term "standard of performance" means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of 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.

This definition includes key factors that must be addressed in an NSPS determination. It must consider cost effectiveness. It must consider energy implications. It must be adequately demonstrated for the application that will be regulated. We believe that EPA has failed to meet these requirements with regard to well completions and storage facilities. In large measure, it fails to meet these requirements because its emissions analyses are inaccurate and its application to segments of the industry fails to be adequately demonstrated and cost effective.

Well Completions

Vertical Well Issues

EPA's definition of a natural gas well completion creates a significant inequity. EPA applies its NSPS requirements to any natural gas well completion that uses hydraulic fracturing. The sweep of this definition would capture natural gas well completions that include only a vertical component and wells with both vertical and horizontal components. However, it is clear that in developing its basis for its reduced emissions completion (REC) or "green completion" technology, EPA bases its determinations on well completions with horizontal legs. Yet, EPA would require the same controls for vertical wells where the emissions would be far less.

Requiring REC on all natural gas well completions makes no sense. There are over 50 depositional basins across the United States that produce oil and natural gas. EPA has only visited a few of them. While there can be similarities in fracturing treatments within a particular formation or depositional basin, there can be big differences between basins across the country. Virtually all of the non-conventional, horizontal completions use large-volume multi-stage hydraulic fracturing treatments, while most of the conventional, vertical well fracture treatments are relatively low volume, single stage events. Applying a one-size-fits-all standard to both types of wells is counterproductive.

If REC remains an option rather than a requirement for conventional vertical natural gas wells, it will continue to be integrated naturally into the flowback process where it is cost-effective and appropriate. However, there are many circumstances where REC is not only inappropriate, but provides little or no environmental or economic benefit. The post-fracturing conditions are more diverse with conventional, vertical well completions than with non-conventional, horizontal well completions.

After a conventional, vertical well is hydraulically fractured, the reservoir pressure may not be high enough to clear the well bore of fluid. If the reservoir pressure is not high enough, the well must have pressure added to artificially help initiate, or "kick-off", return flow. One method is to use a jet pump. A jet pump is run on tubing down the hole and water is pumped down the tubing at pressures as high as 3,000 psig. Located at the bottom of the tubing, small pin holes point upward into the tubing/casing annulus. The flow of high-pressure water from these holes creates a low-pressure zone at the bottom of the well bore that helps to start the gas flowing out of the formation.

A more expensive process is to pump nitrogen down the hole to help clean out fluids remaining in the well bore. Or, liquid carbon dioxide can be used as a fracturing fluid. Both of these options make the flow-back non-combustible, so the flow-back gas cannot be sold to the pipeline or flared. Under these conditions it would not be feasible to use the REC process.

The factors that affect the characteristics of the post-fracturing flowback process vary considerably with conventional, vertical well fracture treatments. These factors include:

1 – The depth of the well;
2 – The thickness of the formations;
3 – The reservoir pressures;
4 – The type of formations;
5 – The type of fracturing fluid used (water, carbon dioxide, nitrogen);
6 – The amount (#/gal) of proppant used;
7 – The amount of treatment fluid recovered;
8 – The ability of the well to flow against the back-pressure of the fluid in the hole;
9 – The need for a jet pump to kick-off the well;
10 – The amount of time needed to clear the well;
11 – The ability to flair the flow back gas; and,
12 – The ability to sell the flow back gas.

The goal of all producers is to stop venting or flaring and start selling the natural gas as soon as possible. It is a matter of economics. If the choice of how to clean up the well after fracturing remains with the producer, REC will be implemented when economically feasible or when required for safety reasons.

The consequences would be severe for these smaller wells. Significantly, most of these vertical wells would be developed by producers many of which are small businesses. Since the natural gas well REC requirements were developed for large horizontal shale gas wells, the distinctions between horizontal wells and vertical ones are pertinent. Many smaller independents are drilling traditional vertical wells that are completed in traditional sandstone and limestone formations. The completions usually take just a few hours. Instead of treating 5,000 feet of a shale formation they are treating 30 to 100 feet of sandstone or limestone. The flowback differs from formation to formation and is usually directed into a lined pit. The goal is to clean out the sand from the well quickly and get the natural gas into the production pad separation equipment and then into the pipeline meter. With the flowback time and volume so much smaller in vertical wells, it is hard to justify separation equipment for a small amount of sand. Additional complexities depending on the nature of the particular formation can be significant.

Wells developed in Kentucky are illustrative. Producers in Kentucky report that if they were required to only perform REC on their wells the entire natural gas production industry could be halted. Currently, because of the low formation pressure on these Shale Gas reservoirs, completion stimulation is done with nitrogen. A typical fracturing process on these shale gas formations is either a "Foamed Frac" using a proppant of sand and conveyed into the formation in an energized fluid made up of mostly nitrogen, or a "Gas Frac" where nitrogen as a gas is the only material pumped down hole to break the rock. In both cases, after the stimulation treatment, the well's flowback is released to the atmosphere until the flow is clean enough to sell into the pipelines. The advantage to these types of completions is that they clean up relatively quickly, use nitrogen which is inert, and the locations needed to drill the wells are kept relatively small compared to the amount of gas bearing reservoir that is developed. No one can tell exactly how much methane is in the nitrogen released back to the atmosphere but it would likely be more than the 100 Ton (4MMcf) limit EPA proposes. Proving the amount released would be difficult and present a burden on the operator. Importantly, there is no way to separate the nitrogen from the flowback stream in order to sell the natural gas as would be required in a REC of a "non-exploratory" well. Even the alternative for "exploratory" wells, allowing the flowback stream to be flared, is not possible during most of the clean up procedure because the nitrogen levels would be too high for the natural gas to burn. Shortly before the clean up is complete, the nitrogen levels would drop low enough that the vented gas could possibly burn, but it would need a large flare pit, which would require the clearing of many more trees in Kentucky's forested areas than are required for the drilling location.

While the Kentucky example may have some unique aspects, the application to vertical wells is far broader. As an example of impacts of this regulation on small operators, consider wells drilled in Pennsylvania (from the PA DEP website):

Year	**Marcellus**	**Non-Marcellus**	**Total**
2005	2	3,653	3,655
2006	11	4,175	4,186
2007	34	4,129	4,163
2008	210	4,039	4,249
2009	768	1,775	2,543
2010	1,446	1,397	2,843
2011 (to 9/31)	1,397	683	2,080

It is safe to assume that all wells were completed with hydraulic fracturing. As can be seen from the DEP statistics, since 2006, the number of Marcellus wells being drilled is rapidly increasing while the number of non-Marcellus wells and the total number of wells drilled is declining. When looking at the data over the 5-year period from 2006 through 2010, there was an average of 494 Marcellus and 3,103 non-Marcellus wells drilled per year. By considering the county locations of the oil patch and of the 3,103 average non-Marcellus wells during those same years, there were an average of 2,132 gas wells and 971 oil or combination oil and natural gas wells drilled per year. As mentioned above, these non-Marcellus natural gas wells are completed in a few hours. If natural gas collection lines have not yet been constructed, costs for these average 2,132 natural gas wells could be as high as $7.5M based on EPA cost information. If natural gas collection lines are available, and again applying EPA cost information and recognizing that these shallow, vertical, stripper gas wells (less than 60 MCF/day average production) will not produce much natural gas and condensate during flowback, the cost for these same wells could be as high as $8.8M. These estimates do not include costs for combination wells. These average costs of $3,523 to $4,146 per vertical well will make many of these wells uneconomical. These wells should be exempt from the proposed regulation.

Emissions Estimates

Regardless of the type of well, the NSPS proposal suffers from inaccurate data on emissions from natural gas well completion. From several accounts EPA's assessment of well completion emissions is based on a small number of instances improperly interpreted and inappropriately escalated to a national estimate. Much of this inaccuracy is presented in the IHS CERA report, *Mismeasuring Methane, Estimating Greenhouse Gas Emissions from Upstream Natural Gas Production*. The analysis points out specific EPA analytical flaws EPA, including:

- The misuse and inaccurate application of Natural Gas STAR program data collected from a small number of wells to assume industry-wide emission rates — based on the erroneous assumption that methane reported as captured through "green completions" would otherwise be vented to the atmosphere when a green completion is not performed.

- EPA's flawed rounding of data points to the nearest hundredth, thousandth, and even ten thousandth Mcf to overcome the "high variability and uncertainty" in the industry — masking a lack of consistent and reliable data that would undermine the EPA conclusions.
- Developing an assumption that producers in Texas, New Mexico and Oklahoma vent to the atmosphere during flowback, rather than commonly flaring or capturing emissions, simply because those states do not mandate flaring or recovery.

The consequences of overstating emissions in the development of NSPS requirements are threefold. First, overstating emissions leads EPA to conclusions that it needs to address operations based on expectations that the facilities present a major cause for regulatory action. Fully understanding the scope of emissions is essential to making appropriate regulatory targeting judgments. Second, in a NSPS determination, EPA is deciding which of several technologies "reflects the degree of emission limitation achievable through the application of 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)" and whether it has been adequately demonstrated in that application. If the emissions are overestimated EPA will make conclusions that are not well founded. The technology's cost effectiveness will be overstated. Similarly, if the demonstration of the technology's use is based on concentrations of compounds that will be higher than those in reality, it may not function properly. Third, overestimation will assure that the anticipated emissions reductions will never occur.

In the proposed NSPS, the extent of overestimation is extraordinarily high. Following the assessments of EPA's determinations of its emissions basis, companies have reviewed operations and evaluated completion estimates more fully. The results show errors not in percentages but orders of magnitude. One company – that had been active in the Natural Gas STAR program used by EPA for some of its estimations – concluded that EPA's estimates were 14 times the company's actual emissions.

Recommendations

EPA's action on this proposed NSPS has been rushed because of its consent decree with WildEarth Guardians and the San Juan Citizens Alliance. Regulatory actions that can fundamentally influence the ability of independent producers to develop America's natural gas should not be driven by court agreement; they should be driven by science and cost effective technology. Given the vast overestimation of emissions from natural gas well completions and the overly broad scope of the EPA definition of fractured natural gas wells that treats verticals wells and horizontal ones identically, we believe that EPA should not issue these standards. Rather, it should carefully evaluate these emissions and then consider what – if any – additional action is needed.

Storage Vessels

Similar issues arise with regard to the NSPS on storage vessels. The NSPS applies to oil and condensate storage tanks and present both issues associated with the impact on small businesses – particularly with regard to regulations being applied to "modified" tanks and associated with the underlying data to justify action. Compounding these aspects is EPA's decision to propose a performance based requirement of a 95 percent reduction in emissions.

Scope of Regulation

While the proposal is cast as a NSPS, it would also apply if a facility is considered to be modified. EPA has attempted to simplify the determination of whether a facility is subject to the regulation by using a throughput basis – 20 barrels/day for crude oil and one barrel/day for condensate. While simpler, the throughput approach is not technically sound or supported by the data. However, it can result in substantial exposure consequences for marginal well operators.

Storage tank capacity must be designed to manage production when a production site is initiated. Over time, production from wells decline. As a well field develops, additional wells are piped to common storage tanks in a tank battery. This basic tank battery system remains in place as existing wells decline and are plugged, as new wells are drilled and begin production, and as existing wells are reworked to increase production. An average marginal well in the United States produces about 2 barrels/day. When a well is reworked, its production may increase to 4 or 5 barrels/day for six or eight months before declining back to its prior flow rate. Even though EPA bases its throughput thresholds on an annual average of daily production, clearly, the consequences of normal well field development could result in a storage tank being under the threshold for one year, over the threshold the next year and below again the year after. Under the proposed NSPS, exceeding the threshold would require equipping the tank with a vapor recovery unit (VRU) or flaring system that would no longer be required by the time it was in place.

Such a requirement creates both economic and safety issues. A marginal well producing operation would be hard pressed to economically absorb the costs of a VRU or flare system. If the tank battery receives substantial volumes of produced water, it may have electricity to power a pump to send produced water to a disposal well. If not, new electric service will have to be run to the site. If the site produces only oil, it likely will not have a natural gas pipeline near and an automatic flare must be used.

Oil field stock tanks that contain crude oil, condensate and produced water are typically constructed with a thief hatch at the top of the tank. This hatch is accessed to measure the amount and conditions of the liquid when it is sold. It also serves as a safety device that will relieve the tank of a vacuum to keep the tank from collapsing and that will relieve the tank from pressure increases to keep the tank from bursting. The tank has another safety valve that is usually located in the center of the top of the tank. These safety valves are rarely calibrated because it requires walking on the tank roof, which is considered to be an unsafe practice. From conversations with oil field engineers, it is possibly as high a 30 percent of tanks triggered for emissions control could require replacement. The main reason for the replacement is the potential that the existing tanks would allow oxygen into the vapor recovery process and create an explosive mixture.

The current proposal does not reflect these realities. They are compounded by errors in the estimates of emissions.

Emissions Estimates

Most of EPA's assessment of storage tank emissions comes from a relatively narrow study in Texas. Using this limited base cannot generate the robust information needed to determine whether the VRU or flare control requirements can be adequately demonstrated to provide a 95 percent reduction in emissions. Moreover, EPA compounds the issue by drawing an arbitrary line to define what constitutes crude oil and condensate with the attendant consequence that falling on the wrong side of the line results in a twenty-fold reduction in the throughput that subjects the tank to regulation.

Moreover, EPA's emissions rate for condensate is substantially higher than other estimates. EPA uses a Volatile Organic Compound (VOC) emissions factor of 33.3 lbs/barrel of throughput. Other analyses such as the Colorado Department of Public Health and Environment determined that emissions rates in Colorado are more likely to range from 10.0 to 13.7 lbs/barrel. Consequently, EPA will overstate condensate emissions at any given throughput by a factor of roughly three. As a result, EPA's determination that its NSPS technology will produce a 95 percent reduction must be called into question.

Recommendations

We believe sources should have the ability to estimate VOC emissions from storage tanks rather than be constrained to a throughput based process. If EPA continues to pursue a throughput based approach, it needs to recognize that a more sophisticated approach should be developed. For example, we understand that API is submitting an alternative throughput look-up table for determining exemptions from the storage tank standards in its comments. A critical action that EPA needs to take is addressing the issue of applying its regulations to existing tanks. It needs to develop an approach that does not create an unreasonable burden on existing production, particularly marginal well operations, resulting from short term increases in production. Consequently, we recommend that EPA withdraw the current proposal, develop better emissions assessments and subsequently revisit the technology requirements.

Conclusion

We believe that the current NSPS proposal fails in two key areas for both the REC for fractured natural gas wells and emissions from storage vessels. In each case the emissions assessments are faulty and need substantial improvement. In each case the scope of the proposal threatens smaller producers and marginal well operations due to inadequate analysis of the effects on these components of American natural gas and oil production. Consequently, we believe that EPA should determine not to proceed with these proposals, develop better emissions estimating tools and revisit the determination of an NSPS based on that new information. We are ready to participate in such future efforts. If there are questions or a need for additional information, please contact me at 202-857-4731 or by email at lfuller@ipaa.org.

Sincerely,

Lee O. Fuller

Lee O. Fuller
Vice President, Government Relations
IPAA