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December 17, 2018

The Honorable Andrew Wheeler, Acting 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 Reconsideration at 83 Federal Register 52,056 (October 15, 2018)

Docket ID No. EPA-HQ-OAR-2017-0483

Dear Acting Administrator Wheeler:

The following Comments are submitted on the above-referenced proposed Reconsideration Rulemaking ("Reconsideration Rulemaking") 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 Producers & Royalty Owners Association ("TIPRO"), and West Virginia Oil and Natural Gas Association ("WVONGA") (collectively, "Independent Producers"). The Independent Producers have participated individually or through the Independent Producers in most, if not all, of the rulemakings and associated litigation since the Environmental Protection Agency ("EPA" or "Agency") proposed to revise the New Source Performance Standards ("NSPS") for the Oil and Natural Gas Sector in August 2011. 76 Fed. Reg. 52,738 (Aug. 23, 2011).[1] While many of the Independent Producers represent companies that engage in large volume hydraulic fracturing with horizontal legs, often referred to as

[1] As the EPA has opened a new docket for the Reconsideration Rulemaking, the Independent Producers incorporate by reference their Comments on the previous rulemakings associated with 40 C.F.R. Part 60, Subpart OOOO and Subpart OOOOa, including but not limited to the following documents: EPA-HQ-OAR-2010-0505-4216, EPA-HQ-OAR-2010-0505-4626, EPA-HQ-OAR-2010-0505-4752, EPA-HQ-OAR-2010-0505-4767, EPA-HQ-OAR-2010-0505-7001, EPA-HQ-OAR-2010-0505-7685, and EPA-HQ-OAR-2010-0505-12337.

unconventional drilling, a significant portion of their membership is comprised of smaller, family run operations that engage in some form of hydraulic fracturing, involving vertical wells without horizontal legs, referred to as conventional oil or gas wells. Many of the individual members constitute as small businesses under the Small Business Regulatory Enforcement Fairness Act of 1996. From the beginning of these rulemakings, the Independent Producers have tried to illustrate to the EPA that their "one-size-fits-all" approach to regulating this industry is a) inappropriate and b) disproportionally impacts conventional operations and small businesses.

Other than the proposed revisions to requirements primarily associated with low production wells, storage vessels, and alternative methods of emissions limitations ("AMEL")/emerging technology, the Independent Producers generally support the proposed revisions in the Reconsideration Rulemaking and appreciate the EPA's effort to improve and 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 more than adequate protection of the environment. The EPA should not lose sight of the simple and somewhat unique fact that what the Agency and some stakeholders view as a pollutant is the Independent Producers' product. The members of the Independent Producers have a pure economic motivation to capture every molecule of methane possible and avoid waste.

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- The EPA should use the Tax Code definition of "stripper well property" as its low production well definition to avoid confusion and challenges to its definition.

- The EPA should defer any fugitive emissions regulations of low production wells until it obtains information on emissions from low production wells. Specifically, the EPA should first determine whether a low production well program is appropriate and cost-effective, and the design a program based on accurate emissions information from low production wells. The Department of Energy ("DOE") is initiating a research effort to provide specific low production well emissions information that can inform these decisions and actions.

- The EPA should exempt booster compressors associated with low production wells from the current compressor fugitive emissions program requirements and incorporate them into whatever low production well program decisions it makes.

B. Storage Vessels

- The EPA's proposal to prohibit averaging of throughput across tank batteries inappropriately ignores the relevant process unit and is inconsistent with recent consent decrees related to the design and operation of vapor control systems on storage tanks/vessels.

- The EPA's concern about the amount of storage vessels subject to Subpart OOOOa is overstated and unfounded.

- The EPA's proposal to calculate individual tank emissions based upon throughput to each individual tank is technically flawed and overly burdensome.

- The EPA's proposed revisions to what constitutes "legally and practically enforceable limits" is unnecessary and arbitrarily interferes with the Clean Air Act's ("CAA" or "Act") cooperative federalism where the states are to take the lead on implementation.

C. AMEL – Emerging Technology

- The Independent Producers support the options in the Proposed Revisions to use modeling, to test technologies in a controlled test environment, and to allow manufactures/vendors to apply for approvals.

- The EPA should allow for basin-wide approvals of emerging technology for use in complying with the leak detection and repair ("LDAR") requirements in the rule.

    - The EPA can establish clear and consistent parameters under which a technology will be able to detect methane emissions and site specific variables can be addressed in conditions required for the use of the technology.

    - Basin-wide data is necessary to determine equivalency and receive approval per CAA 111(h); basin-wide surveys that can identify potential fat-tail emission sources faster and per the EPA, higher mass emission reductions from large leaks, found earlier, are offset by some degree by smaller leaks which go undetected.

    - Common sense dictates basin-level approval; the 111(h) notice and comment process required to achieve approval is very onerous and not feasible to do for every single well site.

    - CAA Sec. 111(h)(3) does not constrain basin-wide approvals.

D. AMEL – State Equivalency

- Per cooperative federalism, the EPA should recognize the approved state programs as wholly equivalent to 40 C.F.R. Part 60, Subpart OOOO's ("Subpart OOOO") LDAR program and fully delegate the implementation of the LDAR monitoring provisions to these respective states.

- Alternatively, the EPA could require the fugitive emissions component definition from Subpart OOOOa to be used when following an alternative approved state program but the EPA should not require a duplicative administrative burden; to do so would be an undue burden with no corresponding environmental benefit.

E. Recordkeeping and Reporting

- While the Independent Producers suggest additional revisions to the frequency of the fugitive emissions monitoring surveys, the proposed changes are likely to be the most beneficial change for industry, while having no detriment to the environment.

- The EPA continues to underestimate and underappreciate the burden on the industry, especially small business, associated with recordkeeping and recording that serves no environmental benefit, *e.g.*, compliance assurance.

F. Definition of Modification

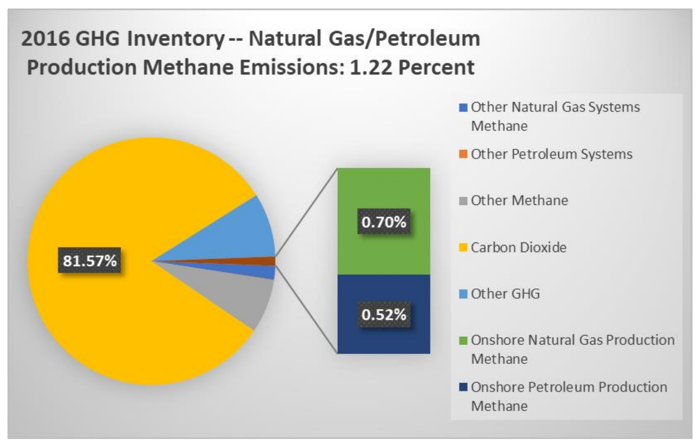
- The EPA's assumptions associated with emissions increases resulting from refracturing wells are unwarranted and unsupported.

- If the EPA persists with defining a refracture as a modification; operators should be able to demonstrate, pre-fracture, that the system is tight and therefore the refracture does not automatically constitute a modification.

II. <u>LOW PRODUCTION WELLS</u>

A. Subpart OOOOa Regulations Need to be put in Context.

The EPA has promulgated during the past decade a number of regulations that are global climate related. Some of these are active; others are being reconsidered. For the oil and natural gas production industry, the two of greatest interest are Subpart OOOO in 2012 and Subpart OOOOa in 2016. While the initial Subpart OOOO regulation was volatile organic compound ("VOC") based, it also reduces methane because VOC and methane are produced and, therefore, emitting together. Subpart OOOO addressed the larger emissions sources related to oil and natural gas production including Reduced Emissions Completions ("RECs") for hydraulically fractured natural gas wells, pneumatic controllers, and storage vessels. Its successor regulation – Subpart OOOOa – addressed a second tier of emissions including RECs for hydraulically fractured oil wells, pneumatic pumps, and fugitive emissions. The current proposed revisions to Subpart OOOOa fine tune these prior regulations to address issues where those prior actions are excessive or need a better structure. However, all of these regulations must be put in the larger context of climate – of greenhouse gases ("GHG") emissions.



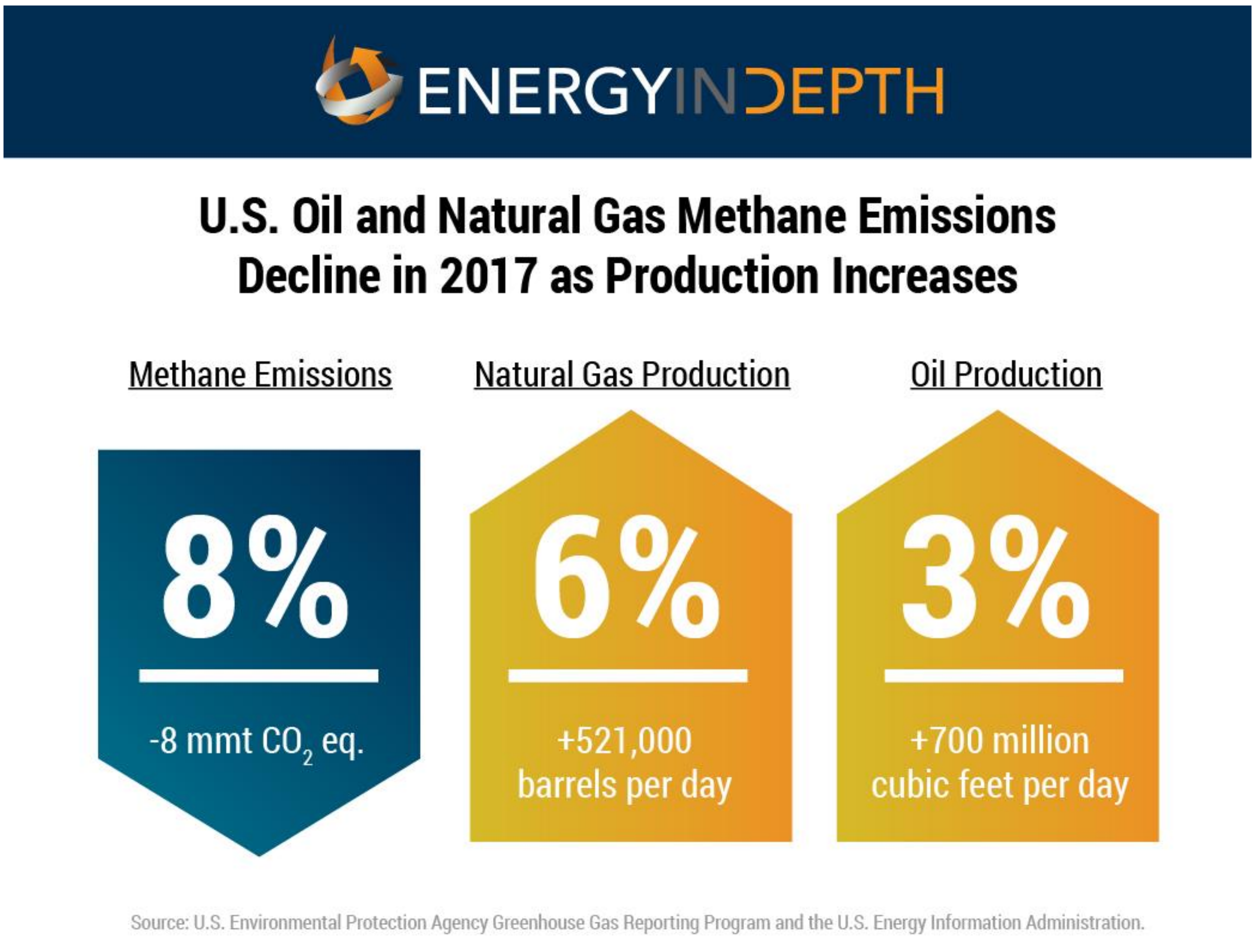
1. **<u>Natural gas and oil production methane emissions are about 1.2 percent of the 2016 GHG Reporting data.</u>**

According to 2016 EPA GHG Reporting data, methane emissions from oil and natural gas exploration and production are 1.22 percent of total U.S. GHG emissions. However, even these estimates may be overstating oil and natural gas production emissions. Most of the emissions calculations are based on emissions factors that come from analyses done in the mid-1990s. Newer analyses call into question a number of these emissions factors. A number of these inaccurate factors are also used in developing emissions tables for the regulatory proposals in the revisions to Subpart OOOOa. These will be addressed more specifically later in these comments.

2. <u>Production methane emissions are declining as production is increasing.</u>

More importantly, these methane emissions are declining as oil and natural gas production is increasing. From 2007 through 2016, U.S. shale gas production grew over 1,300 percent,[2] while methane emissions have declined.

More recently these trends continue, as reported in the Energy In Depth ("EID")[3] blog below. Later data supports the previous results.



New EPA data showing the United States continued to lead the world in greenhouse gas (GHG) emission reductions in 2017 – a trend largely attributable to increased natural gas use – got quite a bit of attention last week.

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

[3] Energy In Depth is a project funded by the Independent Petroleum Association of America, a member of the Independent Producers.

But largely overlooked was the fact that the same Greenhouse Gas Reporting Program (GHGRP) data also show that petroleum and natural gas system methane emissions from reporting facilities declined eight percent from 2016 to 2017.

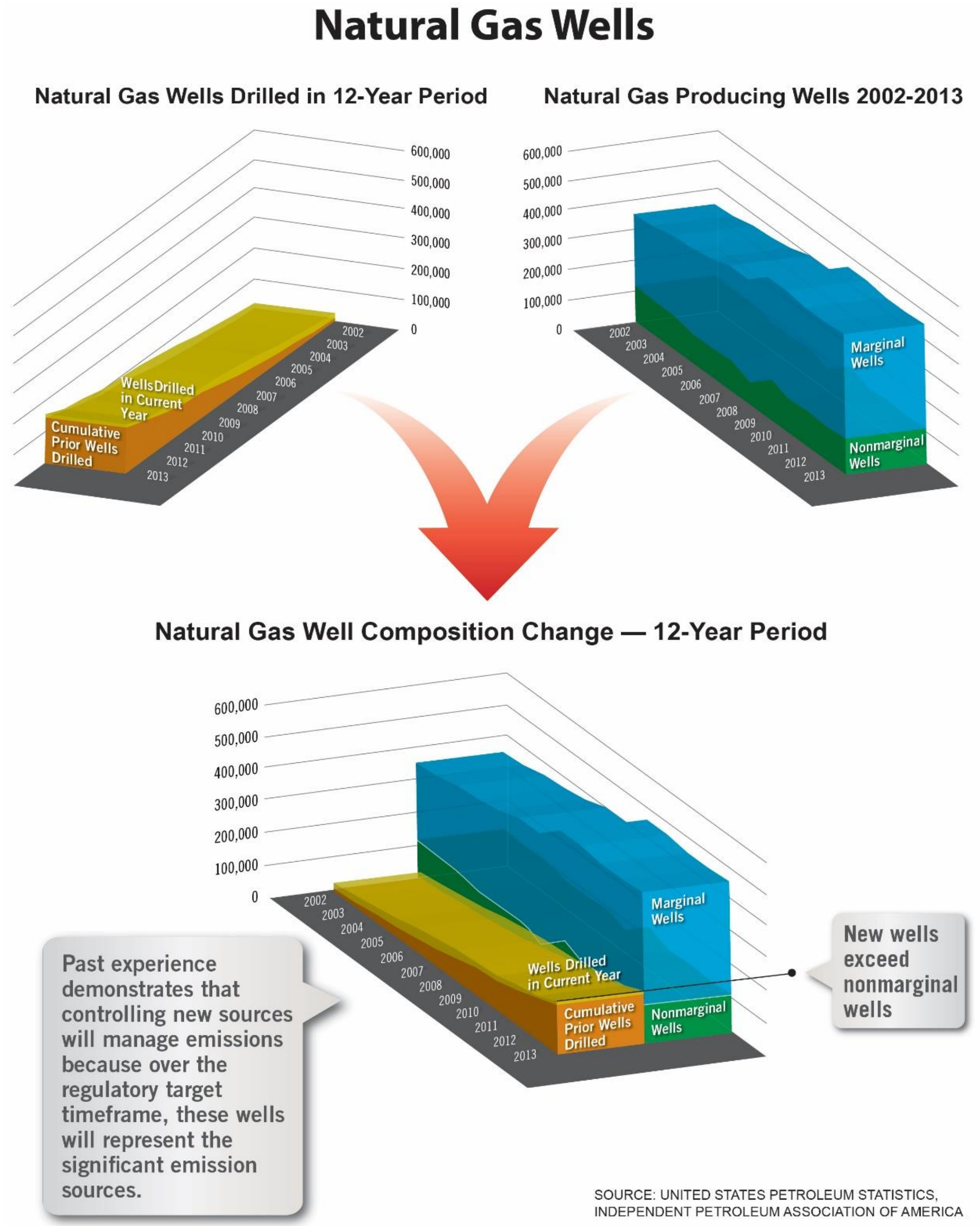
Specifically, the data show methane emissions from large oil and natural gas facilities declined eight million metric CO_2 equivalent in 2017. These reductions came at the same time oil and natural gas production increased six percent (521,000 barrels per day) and three percent (700 million cubic feet per day), respectively, from 2016 levels.

These trends prove once again that the U.S. oil and natural gas industry is effectively reducing methane emissions even as record-shattering production has made the United States the world's leading oil and gas producer.

3. **This trend will continue as new sources built since 2011 with low emissions technologies mature and displace older wells, but the regulatory proposal does not address its impact on the existing wells that would be captured in the regulations despite the declining emissions from the oil and natural gas production sector.**

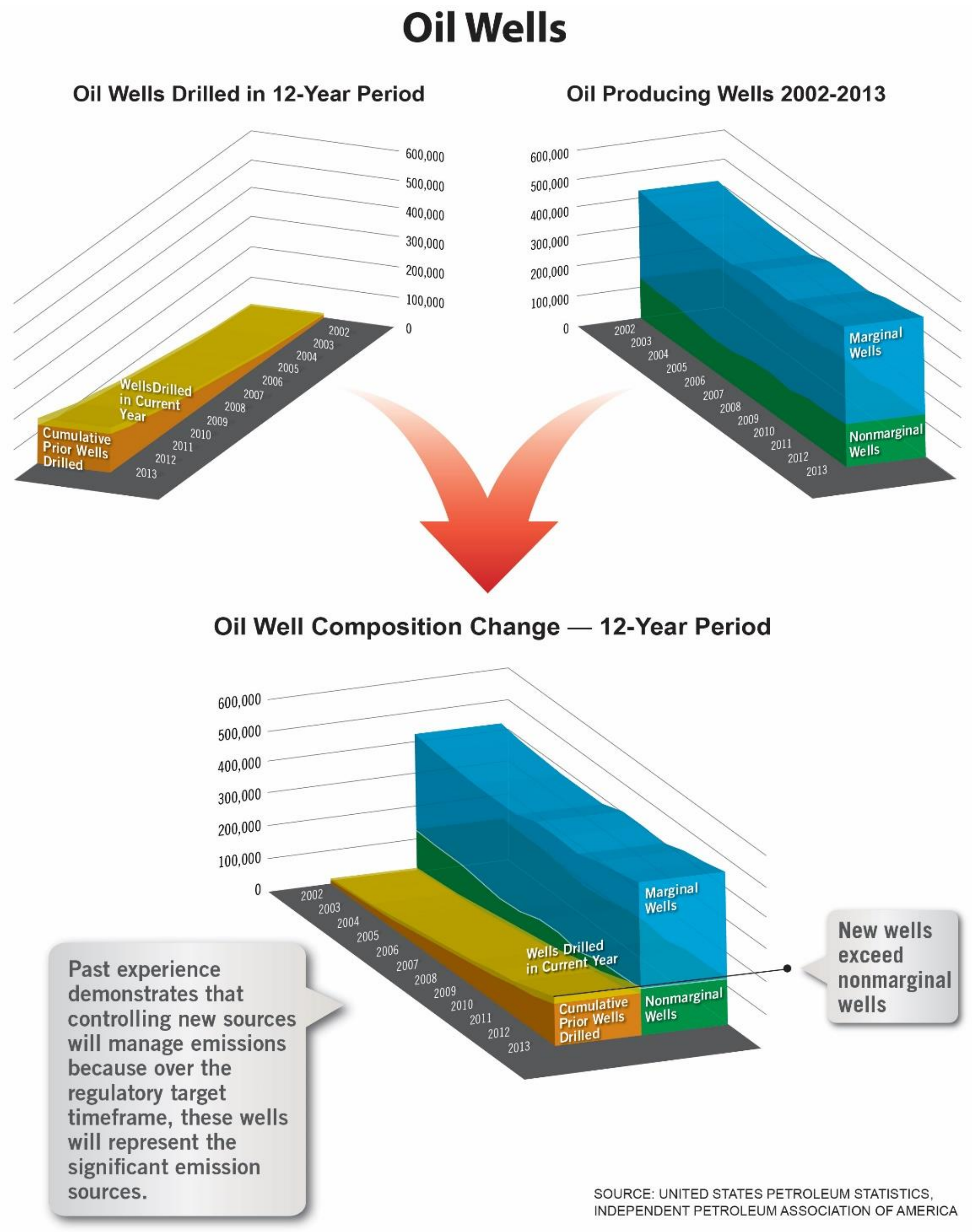
Moreover, because of the nature of oil and natural gas production, the application of controls on new sources will achieve the emissions reductions objectives without the need to create extensive existing source regulations. Oil and natural gas production operations differ from other types of manufacturing. 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 1.22 percent of emissions, yet the EPA's decision to regulate methane directly under Section 111(b) of the CAA subjects hundreds of thousands of existing wells to regulation. The Independent Producers assert that the application of the proposed requirements to existing sources is not effective. The regulatory burden on state and federal regulators of exposing hundreds of thousands of existing sources is completely overlooked in Subpart OOOOa and the EPA was obligated to consider the cost in promulgating Subpart OOOOa and the Proposed Revisions.

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 or as the proposed regulations describes them, "low production" wells. These are defined as wells that produce 15 barrels/day ("B/D") of oil or less and 90 thousand cubic feet per day ("mcfd") or less of natural gas. Currently, there are over 1.1 million oil and natural gas wells in the United States; approximately 770,000 are marginal wells. However, these small individual wells account for about 10 percent of U.S. oil production and 11 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 is more than adequate to address reducing methane emissions from the oil and natural gas sector, in general, and the exploration and production segment, in particular. The EPA's use of methane based regulation exposes the hundreds of thousands of existing marginal wells to regulation under

Section 111 of the CAA, and the EPA has failed to adequately account for and justify subjecting these existing exploration and production sources to such regulation.

B. The EPA Should Provide for a Low Production Well Distinction within Subpart OOOOa.

In its initial Subpart OOOOa regulatory proposal, the EPA chose to exclude low production oil and natural gas wells. The Independent Producers supported this concept because low production wells are an insignificant contribution to national methane emissions and, additionally, they cannot absorb the costs of the EPA fugitive emissions programs designed for large production wells. The economic viability of most of these wells is uncertain because of other additional state and federal requirements and low natural gas prices. However, in finalizing Subpart OOOOa, the EPA removed the low production exclusion. This is an error.

The EPA has now proposed to reinstate a low production well distinction but has not gone far enough. The proposed biennial fugitive emissions surveying for low production wells is helpful but is insufficient for three critical reasons: 1) the Independent Producers believe that with the proper studies, sampling, and testing, the low production wells will fall below reasonable emissions standards; 2) even on a biennial basis, the fugitive emissions survey requirements are not cost effective; and 3) as long as the NSPS are based on methane emissions versus emissions of VOCs, hundreds of thousands of existing wells will be exposed to unnecessary controls and costs.

1. <u>The EPA's proposed low production well provisions are inappropriate</u>.

a. The EPA fails to recognize that wells ultimately become low production wells and many wells begin as low production wells. This changes the cost effectiveness of its regulations.

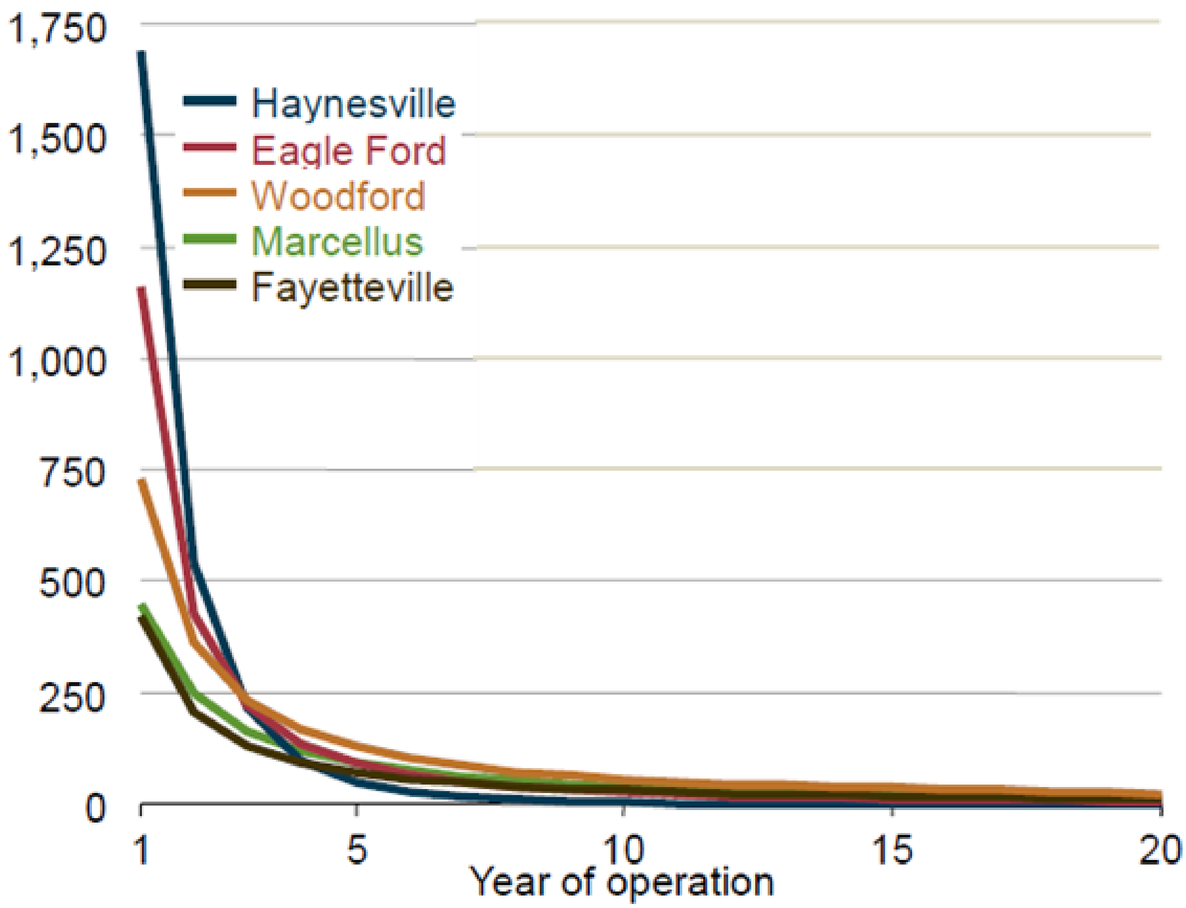
While Subpart OOOOa primarily addresses new sources, it fails to recognize the preeminent reality of oil and natural gas production – all wells deplete and decline in production over time. The reality of oil and natural gas well depletion has been well recognized since oil and natural gas production began. The 1940 book, <u>This Fascinating Oil Business</u>, includes this description:

> …The production of all wells in which gas is the chief expulsive force and which are produced to capacity declines rather rapidly. This decline is especially noticeable in the early stages, from the "initial production" through what is known as the "flush" period and is less noticeable after the "flush production" is gone and the well is on "settled production," but the decline continues just the same.
>
> If the well is producing at capacity the decline is quickly noticeable; if it came in at two thousand barrels a day, in six months it may be down to a thousand barrels and in a year to six hundred. If the well is allowed to produce only a part of its potential production the decline may not be noticeable for a long time; the decline in pressure will be slower, for one thing, and for another, a well allowed to produce only twenty barrels a day will probably behave much the same whether its full productive capacity is two thousand barrels or only two hundred. Sooner

or later, however, the well will fail to make the twenty barrels or one hundred or whatever amount it has theretofore been producing, and from that time on its decline will be apparent. Unless it goes to water the well may produce for twenty or fifty or even seventy years, but each year it will produce less than the year before.

Fields and individual wells vary greatly, but in general this year's production from a settled well produced to capacity will be from ten to thirty per cent less than last year's.[4]

Decline continues to be an integral part of oil and natural gas production, but its nature has changed. The graphic below demonstrates that unconventional wells begin as high production operations, decline rather quickly, and ultimately become low production wells.

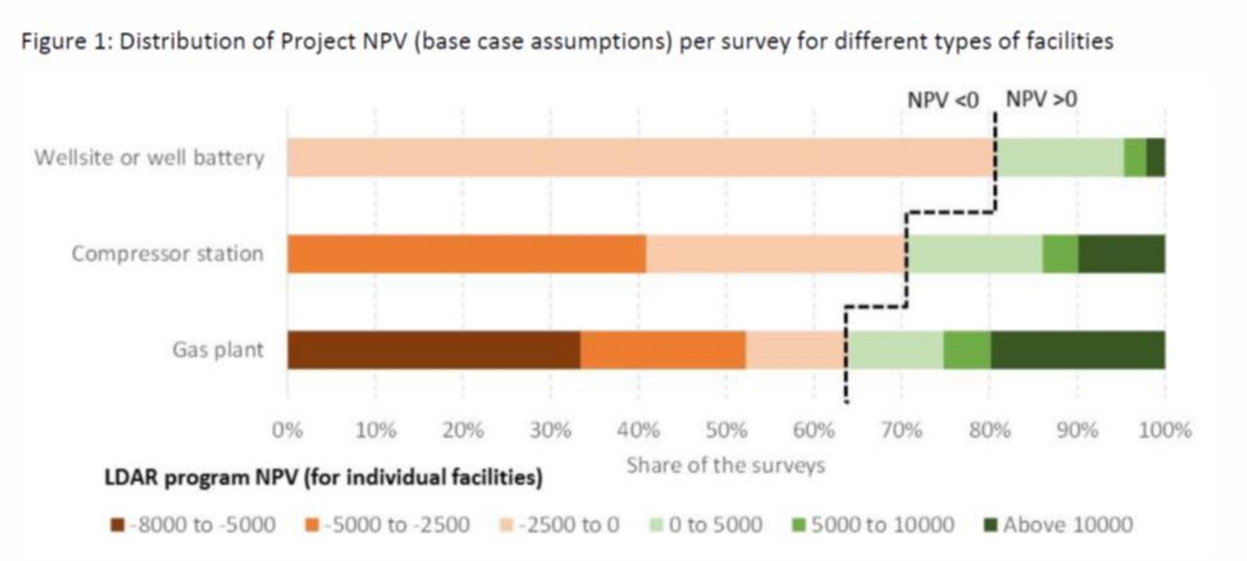


Consequentially, the EPA's determinations regarding the cost effectiveness of its fugitive emissions requirements on wells must be carefully examined. What may be a cost-effective

[4] Ball, Max W., This Fascinating Oil Business, The Bobbs-Merrill Company, 1940, p. 142.

program for high production operations will be very different as wells decline and become low production wells.

Unfortunately, this is not a new issue, but it is an issue that the EPA has largely ignored in the Subpart OOOOa regulatory process. In March 2014, Carbon Limits released a report: Quantifying Cost-effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras.[5] This report produced a particularly telling assessment of the type program included in the Subpart OOOOa regulations and in the revised proposal. Notably, the report showed that the effectiveness of these LDAR programs for wells and well sites is highly limited. The following graphic is illustrative.



As the graphic demonstrates, for 80 percent of well sites, the LDAR program would create more than just an ineffective cost burden; it would create a negative net present value ("NPV"). Moreover, these results 'are based on natural gas prices of $4/mcf natural gas – well above the historic prices in the U.S. marketplace.

Most of these negative NPV wells are low production wells – wells that produce less than 15 B/D which is equivalent to gas production wells of 90 mcfd. Other experience with LDAR programs on low production wells demonstrates that the cost is excessive.

A California example is illustrative. This data comes from approximately 2,900 wells with an average production of 3.6 B/D; it includes 580,324 inspections which found 667 leaks. Using Leaker Emission Factors from 40 C.F.R. Part 98, Subpart W ("Subpart W") and assuming the leaks existed the entire quarter, the results are as follows:

Emissions Found

[5] See Quantifying Cost-effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras, Carbon Limits (May 13, 2014), available at https://www.epa.gov/sites/production/files/2016-04/documents/quantifying_cost-effectiveness_leak.pdf

- 142 leaking valves at 13.9 thousand cubic feet ("mcf") per quarter ("qtr") leaker factor = 1974 mcf.

- 525 leaking connections at 12.3 mcf/qtr leaker factor = 6,457 mcf.

    - Total emissions = 8431 mcf

Cost of Recovered Gas

- The annual operating cost of LDAR equipment and crews only = $800,000. This is a low cost compared to existing Subpart OOOOa semi-annual requirements which has an estimated cost of $1,599/well or in this case $4,600,000/year.

- Using a very conservative estimate of $800,000/8413 mcf = $95/mcf.

- At $1,599/well the cost would be $4.6 million = $546/mcf.

Clearly, the cost of recovered emissions is far different than the value in the EPA's expectations. Importantly, these numbers are too low because the Emission Factor is a generic number – not one based on low producing wells. We will address this issue in more detail below.

However, the key point here is that low production wells need a program designed for their operations.

b. The EPA needs to provide an alternative approach for low production wells rather than a one time, ineffective assessment of a low production well.

In the Reconsideration Rulemaking, the EPA defines a low production well as:

> well sites with average combined oil and natural gas production for the wells at the site less than 15 boe per day averaged over the first 30 days of production ("low production well sites")[6]

As stated previously, oil and natural gas wells ultimately become low production wells. And, as low production wells, they have contributed or will continue to contribute to the nation's energy supply for decades. Currently, low production oil wells account for about 10 percent of American oil production, and low production natural gas wells account for 11 percent of American natural gas production. As a result of the additional cost associated with the fugitive emission surveying requirements in the Reconsideration Rulemaking, low production wells will be prematurely shut in and plugged. The nation will lose this reliable production.

The Reconsideration Rulemaking creates two pools of fugitive emissions requirements – one annual program for large production wells and one biennial program for low production wells. Setting aside for a moment the issues of the cost effectiveness of these programs, the approach creates some absurd results. In the approach taken by the EPA in the Reconsideration

[6] 83 Fed. Reg. 52,062.

Rulemaking, a well with production of 15 B/D after 30 days of production would be subjected to the biennial fugitive emissions program. However, a well with 18 B/D of production after 30 days would be perpetually in the annual fugitive emissions program even though it will clearly be below the 15 B/D threshold soon after its production starts.

Instead of this unworkable and unfair system, the EPA needs to craft an approach that allows wells when they begin producing less than 15 barrels of oil equivalent ("BOE") to shift to an alternative fugitive emissions program – a program based on the emissions pattern of low production wells. Such an approach would encourage the continued operation of wells as they decline but collectively provide an important component of the American oil and natural gas resource base.

Such an approach would not pose any adverse impact on the environment. First, the pool of wells producing American oil and natural gas is constantly changing. As it changes, older wells are being replaced with: 1) wells that meet the requirements of Subpart OOOO; and 2) many wells that used those technologies before Subpart OOOO as a part of the Natural Gas STAR program. Second, assuming the alternative as described above is created, a substantial portion of new wells are drilled on sites with multiple wells. Those well sites would continue to be subjected to the Subpart OOOOa fugitive emissions requirements until all of the wells became low production wells. Third, as discussed *infra*, the DOE is initiating a research program to define the emissions profile of low production wells. The EPA should use the results of that research to design an appropriate low production fugitive emissions program rather than try to shoehorn these wells into a program that was never designed for these operations.

Until then, the EPA should choose to act as it has in the October 2016 Control Techniques Guidelines ("CTG") for VOC emissions from existing oil and natural gas production facilities in ozone nonattainment regions and defer action on a low production well fugitive emissions program.

c. A Low production well is a low production well – regardless of when the well is drilled.

Characterizing wells in perpetuity based on the wells' first 30 days of production is arbitrary and unnecessary. The term "low production well" is a construct of these NSPS rulemakings but the concept or characterization of this category of wells is not new to the industry. The most recent characterization of "low production well" largely tracks commonly used approaches to defining smaller wells whether using the term low production well or marginal well or stripper well. These terms spring from the stripper well definition in the tax code. The use of the tax code definition should serve well as a definition for a "low production well" in any revisions to Subpart OOOOa that provide for regulatory actions regarding these wells. A principal issue in developing the low production well concept will be its application to each well. Inevitably, there will be challenges. Use of the tax code stripper well definition provides a long history of such determinations. It also provides a framework that is well understood by the regulated industry.

For example, one of the key issues in understanding the definition a low production well will be addressing production of both oil and natural gas which are common elements of these wells. That is, most oil wells will have associated gas and most natural gas wells will have natural gas liquids. These issues have arisen in the determination of stripper wells, and the process to determine their status has been refined over the years.

The essence of the stripper well provisions is found in Section 613A of the Tax Code. A stripper well is defined in Subsection (c)(6)(E):

> For purposes of this paragraph, the term "stripper well property" means, with respect to any calendar year, any property with respect to which the amount determined by dividing—
>
> > (i) the average daily production of domestic crude oil and domestic natural gas from producing wells on such property for such calendar year, by
> >
> > (ii) the number of such wells,
>
> is 15 barrel equivalents or less.

The calculation process to make this determination is straightforward. All production is converted to oil equivalents. To convert gas production to oil equivalents, a ratio of 6,000 cubic feet equals one barrel of oil[7]. Consequently, 90,000 cubic feet equals 15 barrels; this is the source in the low production definition that uses 15 B/D or 90 mcfd as its basis. However, the reality of the calculation revolves around putting all production on a common basis – oil. Thus, if a well produces 10 barrels of crude oil and 12,000 cubic feet of natural gas, its equivalent barrels produced would equal 12 (*i.e.*, 10 + (12,000 / 6,000)). This approach then resolves questions regarding how to evaluate wells with both oil and gas production.

Clearly, another issue that arises will be the application of the stripper well definition in the context of compliance assurance with Subpart OOOOa. Compliance assurance is always a significant question. But, using a known and understood criteria provides industry with a clearer standard. Most of the instances where the issue would arise is when a well declines, and this is the normal circumstance under which a well is assessed as a stripper well. The other instance that arises relates to the initial application of the regulatory requirements – in this instance the fugitive emissions monitoring program. The issue here involves the current requirements in Subpart OOOOa that the initial fugitive emissions monitoring occurs within 60 days of the startup of production, the determination of the well's status 30 days after its initial operation, and the tax code stripper well calculation that uses annual information. However, this issue could be resolved by creating some type of initial production threshold – *e.g.*, 250 B/D – that would suggest the likelihood that the well would decline to a low production well soon after its initial

[7] Section 613A (c)(4) Daily depletable natural gas quantity.

> For purposes of paragraph (1), the depletable natural gas quantity of any taxpayer for any taxable year shall be equal to 6,000 cubic feet multiplied by the number of barrels of the taxpayer's depletable oil quantity to which the taxpayer elects to have this paragraph apply. The taxpayer's depletable oil quantity for any taxable year shall be reduced by the number of barrels with respect to which an election under this paragraph applies. Such election shall be made at such time and in such manner as the Secretary shall by regulations prescribe.

operation. Wells meeting this threshold would have the initial fugitive emissions monitoring program delayed for one year. If the well did not fall below the low production well threshold by that time, the initial fugitive emissions monitoring could be required 60 days later.

Once revised Subpart OOOOa regulations address the pressing issue of providing an exclusion for low production wells and an offramp from the application of the Subpart OOOOa requirements when wells inevitably decline below the low production well threshold, the issue of interpreting the definition will clearly arise. Using the stripper well definition from the tax code brings with it a clear and certain process for determining its application. While the previously used EPA definitions of low production wells parallel the intent of the stripper well tax code definition, a new definition will lead to interpretation challenges that could be avoided.

C. <u>The EPA's Information on Low Production Wells is Inadequate to Develop Regulations</u>.

1. There are approximately 770,000 low production wells in the United States; the EPA is basing its model plant and emissions assessment on about 25 low production wells in one basin.

Perhaps the most significant aspect of Subpart OOOOa versus Subpart OOOO is that it is based on the regulation of methane instead of VOCs. A methane-based regulation not only addresses new and modified sources under Section 111(b), it opens the pathway to a nationwide existing source regulatory scheme under Section 111(d) of the CCA. Consequently, the scope of possible sources expands from the roughly 20,000 wells drilled annually to the 770,000 existing operating oil and natural gas wells. This is a vastly different regulatory expanse.

The EPA's approach to developing its low production well model plant ("Model Low Production Well") in the Technical Support Document ("TSD") and thereby its assessment of the effectiveness of a fugitive emissions program — returns to a fundamental question of the EPA's responsibility and obligation to develop its own data needed for regulatory actions. The data relied upon in the Reconsideration Rulemaking is wholly inadequate.

There are approximately 771,000 low production (marginal) wells in the United States — 394,000 oil wells, 377,000 natural gas wells. These wells are spread across over 30 states. The EPA's reliance on approximately 25 potentially low production wells in one play— the Barnett Shale in Texas — to define its Model Low Production Well is inadequate. This action is flawed for several reasons. First, there is no reason to believe that the Barnett Shale is representative of all low production wells in various plays across the country. Second, the data that was collected in the Fort Worth Study was not intended to address low production wells specifically and is simply a subset of wells incidental to a larger study. Third, even this well selection appears flawed; some wells do not appear to be low production wells. Fourth, and perhaps most importantly, trying to establish a Model Low Production Well on the basis of 25 single basin wells will lead to ineffective results and unproductive, inefficient use of resources

The same issue arises in the emissions analyses by various "Keep It in the Ground" environmental groups. The most prominent of these efforts relies on results from one or two basins, and the low production well data is an unintended subset of the larger study. That is, when the studies are made, there is no understanding of the production from the well. Afterwards, the analyses sort the data based on production, and some subset is low production wells. Even the larger compilations of these studies will include an accidental collection of less than 200 low production wells from one or two basins which is not the appropriate basis for developing national regulatory requirements impacting hundreds of thousands of wells.

2. The EPA's source documents on low production wells are critically flawed.

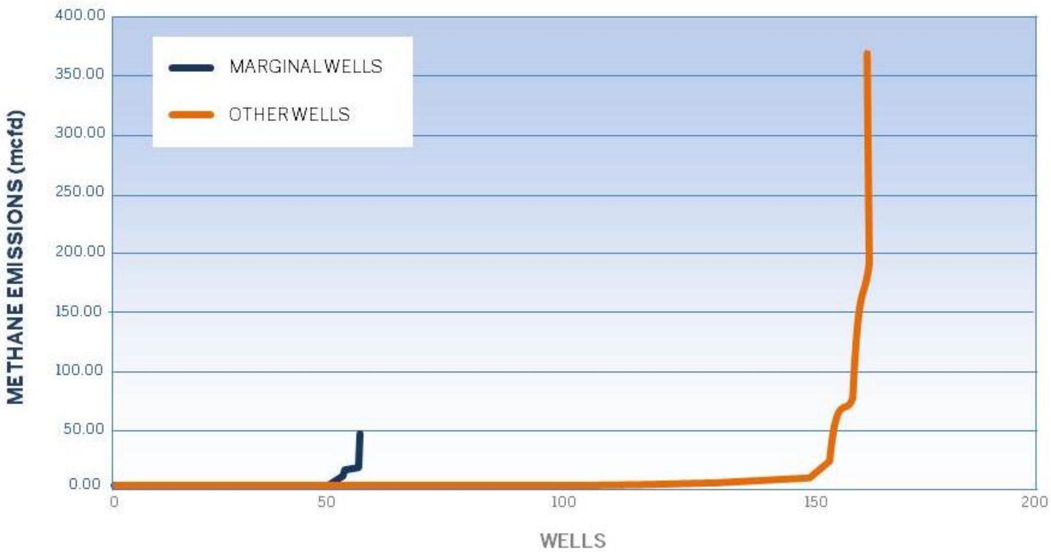
The flaws in the analyses by the EPA and Keep It in the Ground environmental groups that want to influence the EPA's decisions can be seen in a number of actions.

a. The Environmental Defend Fund's Super-Emitters Study is specious.

The Environmental Defense Fund's data manipulation in the study it submitted to the 2015 Subpart OOOOa rulemaking proposal distorts the role of low producing wells regarding methane emissions ("2015 EDF Study"). This study was then characterized as the basis for removing the low producing well exclusion for the Subpart OOOOa fugitive emissions program initially proposed by the EPA.

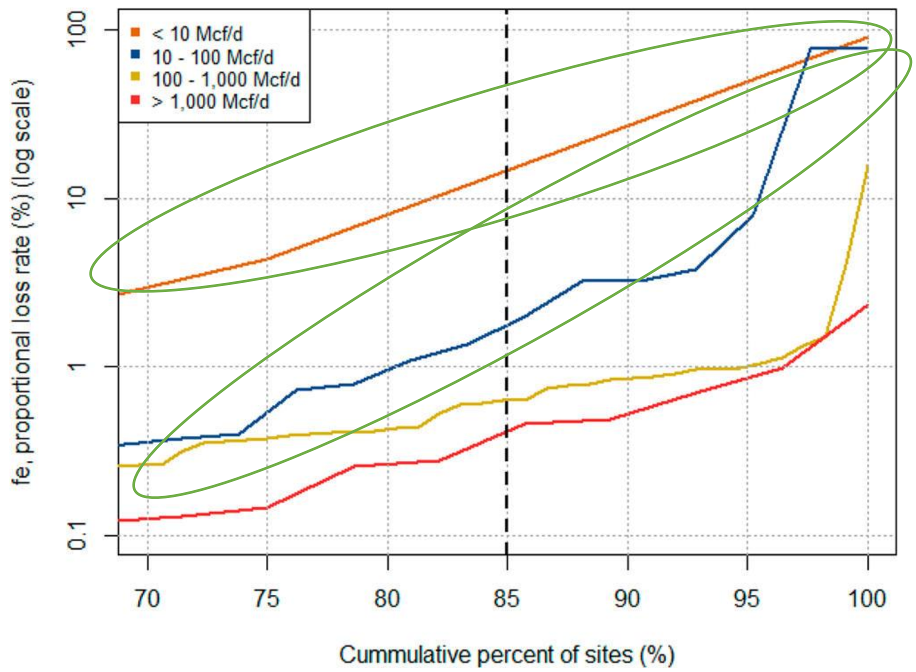
It is important to understand that the 2015 EDF Study used data from a number of different studies to create its arguments. All of the underlying studies generated their data by driving vehicles with samplers downwind of production sites, hunting for methane plumes. None of them used samples taken on the production site. This creates two issues. First, it measures everything emitted at the site – fugitive emissions and permitted vents. Second, the data are collected over minutes – maybe over an hour – but not over a day. The data in the study are presented as if they were daily emissions, but the studies merely scale up hourly estimates. Consequently, emissions that might occur for several hours, but not the full day, would be overstated.

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



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

With this background, turning to the presentation of the same material in the study demonstrates how it was manipulated. Below is the graphic used to present the data. It would suggest that the worst emitting operations – the "super-emitters" – are the smallest wells (the orange line and the blue line, circled in green). Having directly plotted this data, the obvious issue is how such a result can occur.



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

First, it shows emissions as a percentage of production rather than actual emissions. Thus, one mcf emitted out of ten mcf produced is 10 percent, but 50 mcf emitted out of 1,000 mcf produced is five percent. As a result, it skews the perception of the data to imply that low production wells are large emitters when they are not.

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

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

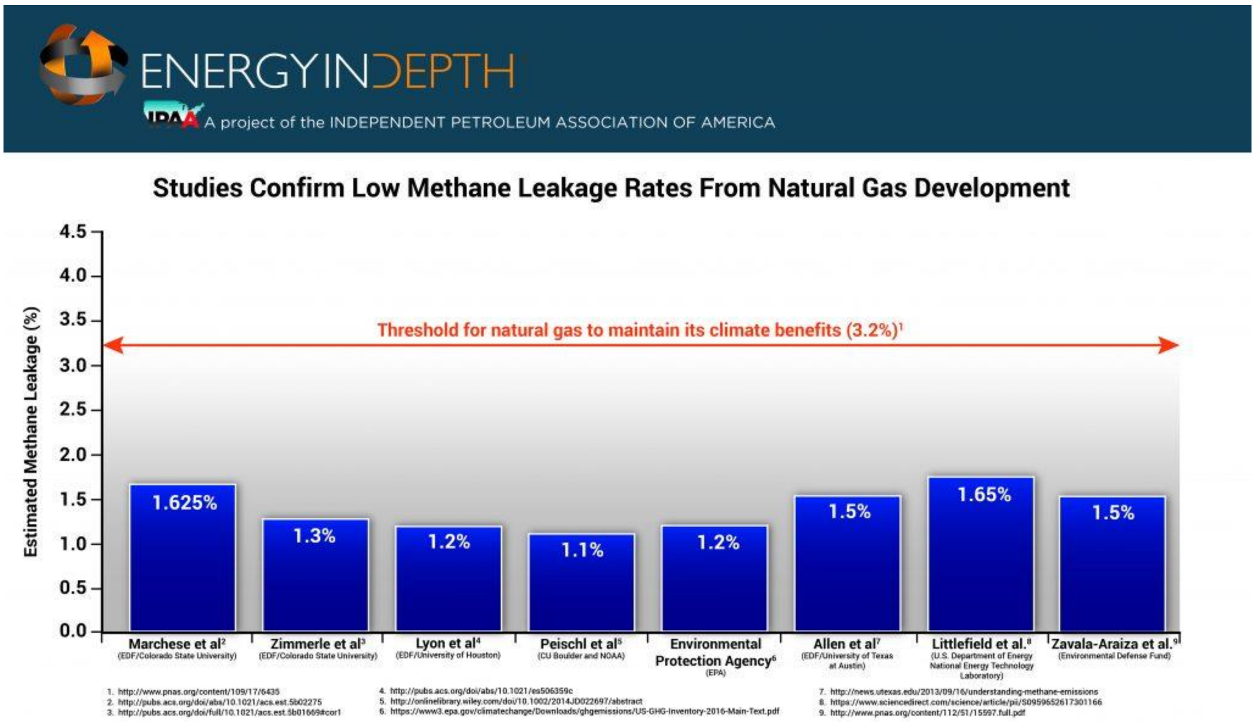
Fourth, it uses a logarithmic scale to present the data. One of the reasons to use logarithmic scales is to flatten curves to make them look more like straight lines.

The EPA should not have relied on such a specious report to make a regulatory decision with profound effects on the future of American oil and natural gas production.

b. The EDF 5-Study report is equally flawed.

In May 2018, EDF released another methane emissions study ("2018 EDF Study") that it heralded as another example describing the underestimation of national methane emissions and demanding more federal regulation. It is as specious as the 2015 EDF Study and should be given no import by the EPA in assessing regulatory options. Following is a discussion of its key failings.

To put this discussion in context, the EID addressed the 2018 EDF Study.[8] Its analysis follows:



> *The Environmental Defense Fund (EDF) has **released a myriad of studies** on natural gas system methane emissions over the past six years that have found low leakage rates between 1.2 and 1.5 percent of production. Five such studies are featured in the following EID graphic.*
>
> *So the fact that a new EDF **study** released today finds methane leakage rates of 2.3 percent — well above what EDF-led research has previously found and "60 percent higher than the U.S. EPA inventory estimate," according to the report — begs the question: What changed with regard to EDF's methodology for this study that yielded a much higher leakage estimate than its past research has shown?*

[8] Whitehead, Seth, Five Things to Know About New EDF Methane Study, Energy in Depth (June 21, 2018), https://www.energyindepth.org/five-things-to-know-about-new-edf-methane-study/

Turns out, quite a lot changed, and most of the changes raise red flags regarding the study's conclusions. Not only did the authors of the new EDF study — which includes no new measurements and instead calculates national methane emissions based on past studies — opt not to use past EDF research as a basis for their emissions calculations, it relies exclusively on five far less comprehensive facility-level studies that lacked industry participation to arrive at its conclusion of higher U.S. emissions than previously reported. In contrast, an "alternative" calculation, based partially on EDF's past studies, that finds emissions in line with current EPA estimates is buried in the study's supplemental data and is not even mentioned in the report.

These are just two of several key issues regarding the manner in which EDF conducted this study that appear aimed at producing the most extreme emissions estimate possible ahead of the 27th annual ***World Gas Conference*** *(WGC), which begins Monday in Washington, DC. Here is a deeper look at each issue.*

#1. Exclusive Use of Facility-Scale Study Data Goes Against National Academy of Sciences' Recommendations and Likely Exaggerates Emissions

This study's national methane emissions estimate is based entirely on downwind, facility-based studies. From the report:

"In this work we integrate the results of recent facility-scale BU studies to estimate CH4 emissions from the U.S. O/NG supply chain, and then we validate the results using the TD [top-down] studies."

However, a recent National Academy of Sciences (NAS) ***report*** *aimed at improving national methane emissions inventories recommends a more comprehensive approach combining "bottom-up" measurements — both of the component- and facility-level variety — along with "top-down" measurements:*

"Coordinated, contemporaneous top-down and bottom-up measurement campaigns, conducted in a variety of source regions for anthropogenic methane emissions, ***are crucial for identifying knowledge gaps and prioritizing emission inventory improvements****. Careful evaluation of such data for use in national methane inventories is necessary to ensure representativeness of annual average assessments."*

EDF has conducted studies combining the comprehensive top-down/bottom-up methods recommended by NAS before. ***Zavala-Araiza et al.*** *is the most notable example, and that study found a methane leakage rate of just 1.5 percent. Just as notably, a recent National Energy Technology Laboratory* ***study*** *based on Zavala-Araiza et al. data estimates national methane emissions at 1.65 percent. That report involved several of the co-authors of this most recent EDF study that reached much different conclusions.*

The new EDF report argues that using facility-level measurements exclusively is appropriate because component-based studies can "under-sample abnormal operating conditions" such as malfunctions and large leaks. But this rationale ignores flaws with facility-level measurements that can lead to overestimation of emissions. For instance, facility-level measurements can capture episodic emissions, such as liquids unloading, *and inaccurately characterize them as normal emissions that would be occurring 24 hours a day, seven days a week. The latter issue can be exacerbated when researchers lack a fundamental understanding of the facilities where they are taking measurements, which brings us to the next major issue with the study.*

#2. Lack of Industry Collaboration Goes Against National Academy of Sciences' Recommendations

With regard to the ground-based, facility-level studies used as the basis for estimating national emissions in this report, the report's supplementary information document notes:

"Sites were reported to be sampled on a quasi-random basis ***without advance operator knowledge****."*

Not only does EDF admit that some of the studies used did not conduct truly random sampling, it admits that industry wasn't involved in these studies on any level. This again flies in the face of recommendations made in the ***NAS*** *report, which states:*

"[V]erifiability is the bedrock upon which inventories should be built if they are to be widely applicable to policy needs."

The lack of industry participation is surprising, considering EDF's past methane research is well known to have been a collaborative effort between EDF, academia and industry, a fact EDF has frequently ***touted****. But even more surprising is EDF's justification for excluding industry from participating in this particular study. From the report:*

"Operator cooperation is required to obtain site access for emission measurements. Operators with lower-emitting sites are plausibly more likely to cooperate in such studies, and workers are likely to be more careful to avoid errors or fix problems when measurement teams are on site or about to arrive. The ***potential bias*** *due to this 'opt-in' study design is very challenging to determine. We therefore rely primarily on site-level, downwind measurement methods with* ***limited or no operator forewarning*** *to construct our BU estimate."*

Not only does EDF fail to provide a single reference to back up this claim of "potential bias" that it claims necessitated it to use the methodology highlighted above, but none of the five co-authors of this report, who were also the lead authors of past EDF methane research that was conducted in close concert with industry,have ever publicly claimed any "bias" whatsoever. Not once.

EDF's assertion appears to be purely speculative in nature and also appears to be an excuse to use these studies as a basis for exaggerated national emission estimates.

#3. "Alternative" Emissions Estimate That Is In Line With EPA Greenhouse Gas Inventory (And Past EDF Research) Is Not Included In Report

In the supplemental materials document for this report, EDF includes the following "alternative" national emissions estimates based on source-based reports, several of which are past EDF studies.

Source: Table S3	GHGI	Source-based EDF estimate (Gg CH_4/yr) – Alternative EDF estimate	Site-based estimate (Gg CH_4/yr) – Primary Method
Total U.S. Oil and Gas Supply Chain	8,100 (6,800 – 10,000)	8,800 (8,400 - 9,700)	13,000 (12,000 - 15,000)

Source: Alvarez et al. supplementary materials

*This "alternative" estimate finds the national methane leakage rate is 1.4 percent, which (not surprisingly) not only aligns with past EDF studies, but also the **EPA Greenhouse Gas Inventory**.*

Remarkably, the data from this "alternative" estimate isn't mentioned at all in the actual report, even though EDF notes that an extensive list of source-based studies featured in the supplemental data of the report has "dramatically improved understanding of the sources and magnitude of CH4 emissions from the industry's operations."

EDF also argues that its "primary" estimate — which, again, is based solely on facility-level studies — is in line with aggregate average emissions found in the following nine "top-down" studies based on emission measurements largely collected via aircraft measurements.

"When the BU estimate is developed in this manner, direct comparison of BU and TD estimates of CH4 emissions in the nine basins for which TD measurements have been reported indicates agreement between methods…"

Table S2. Reported estimates of O/NG CH_4 emissions from aircraft-based top-down (TD) studies, listed in decreasing order of natural gas production. Italicized values were calculated in this work; shaded rows indicate a second independent, statistically consistent set of reported measurements in two basins (not used directly in this work in favor of the more recent results based on more intensive sampling). Uncertainties are 2-sigma values calculated from reported uncertainties.

TD survey area	Reference	Date Sampled (Month/yr)	Days/flights/ downwind transects	NG production (bcf/d)	% CH_4 in NG	Upwind Background Method*	Total CH_4 Flux (Mg/h)	O/G apportionment method†	O/NG CH_4 flux (Mg/h)†	Production normalized emission rate$
Haynesville	Peischl (*51*)	6/2013	1/1/3	7.7	86%	UTA	80 ± 54	SE	*73 ± 54*	*1.3%*
Barnett	Karion (*71*)	3 & 10/2013	8/8/17	5.9	89%	DL	76 ± 13	E	60 ± 11	*1.4%*
NE PA	Barkley (*67*)	5/2015	4/4/7	5.8	95%	MUT	20 ± 17	SE	18 ± 14	*0.40%*
NE PA	Peischl (*51*)	7/2013	1/2	N/A	95%	UTA	15 ± 12	SE	13 ± 12	*0.30%*
San Juan	Smith (*52*)	4/2015	5/5/5	2.8	83%	DL	62 ± 46	N	*57 ± 54*	*3.0%*
Fayetteville	Schwietzke (*47*)	10/2015	2/2/4	2.5	97%	UTSV	31 ± 8	SE	27 ± 8	*1.4%*
Fayetteville	Peischl (*51*)	7/2013	1/1/2	N/A	97%	UT	39 ± 36	SE	35 ± 32	*1.9%*
Bakken	Peischl (*49*)	5/2014	3/3/5	1.9	47%	DL	28 ± 10	SE	27 ± 13	*3.7%*
Uinta	Karion (*69*)	2/2012	1/1/1	1.2	89%	UT	56 ± 30	S	55 ± 31	*6.6%*
Weld	Petron (*70*)	5/2012	2/2/3	1.0	79%	UT	26 ± 14	S	19 ± 14	*3.1%*
W Arkoma	Peischl (*51*)	7/2013	1/1/1	0.37	96%	UT	33 ± 30	S	26 ± 30	*9.1%*
9-basin total				29			410 ± 87		360 ± 92	1.8 ± 0.5%¶

* Upwind background methods: UT=upwind transect; UTSV = spatially variable upwind transect; UTA=upwind transect with adjustments to account for methane above background that flows into a region; DL = downwind lateral plume edges; MUT = model-assisted upwind transect

† Apportionment methods: S= subtraction of inventory-based estimates of non-O/NG sources; E = ethane; SE = subtraction with ethane as qualitative check; N = none

$ Methane emitted normalized by methane produced

¶ Production weighted

Source: Alvarez et al. supplementary materials

But this claim is a stretch on a couple levels. First, the cumulative data from the above "top-down" studies show a national leakage rate of 1.8 percent, well below the 2.3 percent leakage rate this new EDF study claims. Though that is within the study's .5 percent uncertainty range, top-down studies typically overestimate oil and gas methane emissions due to the fact that emissions measurements from such studies are difficult to attribute to specific sources.

In other words, it is highly implausible that "bottom-up" methane emissions estimates would be higher than "top-down" estimates.

*And in fact, a recent National Oceanic Administration (NOAA) **study** finds that top-down studies have likely overestimated emissions by mischaracterizing episodic emissions as normal emissions. Such emissions can also be detected and mischaracterized via facility-level measurements. So it's not surprising that this EDF study tries to discredit that NOAA study.*

#4. Attempts to Discredit Study That Finds Misrepresentation of Episodic Events Can Lead to Inflated Emissions Estimates Via Daytime Bias

*Another factor that can lead to facility-scale measurements overestimating actual normal emissions is the fact that such methods are conducted in the daytime and, thus, can capture emissions from episodic events – such as liquids unloading – that are conducted during the day and inaccurately extrapolate them as if they are constant. This fact was further confirmed by a recent peer-reviewed NOAA study of the Fayetteville Shale **covered** by EID last year.*

Perhaps anticipating that 2017 study would be used to call this new EDF report's conclusions into question, EDF attempts to discredit the NOAA study in the paper:

"[W]e consider unlikely an alternative hypothesis that systemically higher emissions during day-time sampling cause a high bias in TD methods."

"[T]here is no reason to expect daytime bias in the kinds of abnormal operating conditions that are thought to characterize high-emitting production (and gathering) sites, which operate continuously. In fact, it is plausible that abnormal emissions could actually be higher at night because they are less likely to be found and corrected in the absence of operators."

The above claim is directly contradicted by the following, which acknowledges the validity of the NOAA Fayetteville study, but claims it isn't relevant to other basins.

"O/NG emissions are systematically higher during daytime hours when TD and BU measurements have been made, and lower at night. This situation was reported for the Fayetteville Shale but appears to be unique because the effect is caused by manual liquids unloadings, which represent a much higher fraction of total production emissions than in any other basin."

The fact is, events such as liquid unloadings are common in other basins and downwind measurements, such as the ones used as the basis for this EDF analysis, do tend to be higher because they are conducted during the day.

#5. Despite EDF's Alarmist Characterizations, Natural Gas' Climate Benefits Remain Clear

The report claims the oil and natural gas development emissions level estimated in this report combined with carbon emissions from current natural gas combustion is having the same climate impact as coal in the short term (20-year timespan):

"Indeed, our estimate of CH4 emissions across the supply chain, per unit of gas consumed, results in roughly the same radiative forcing as does the CO2 from combustion of natural gas over a 20-year time horizon (31% over 100 years). Moreover, ***the climate impact of 13 Tg CH4/y over a 20-year time horizon roughly equals that from the annual CO2 emissions from all U.S. coal-fired power plants operating in 2016*** *(31% of the impact over a 100-year time horizon)."*

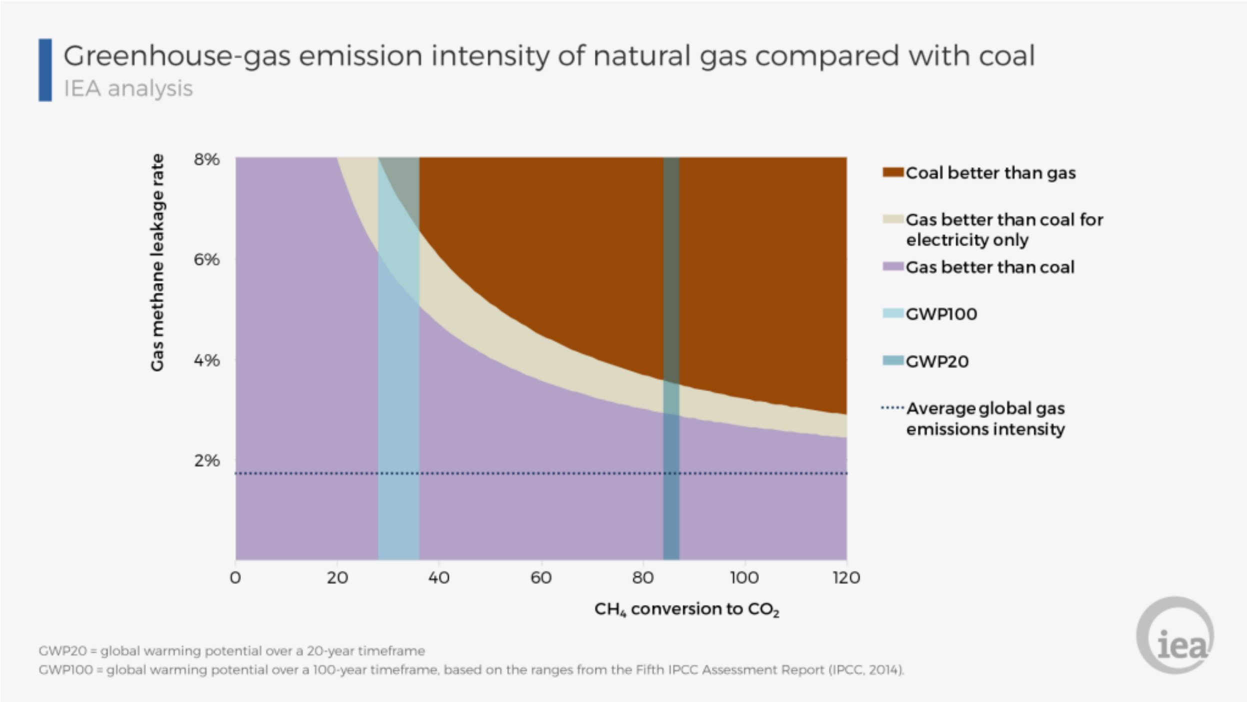
But as alarming as that claim might be, it is essential to note that natural gas maintains clear climate benefits over other traditional sources even at much higher leakage rates than purported by this study.

A recent hydraulic fracturing issues brief published by Washington D.C.-based environmental think tank Resources for the Future (RFF) ***notes****:*

"If more than about 4% of the natural gas produced in the United States is emitted as methane (rather than being burned), the climate benefits of gas's displacement of coal

disappears over a 20-year time frame. If the time frame is 100 years, the leakage rate would have to be more than 8% for natural gas to be a climate loser relative to coal."

The following International Energy Agency (IEA) graphic illustrates RFF's point, showing natural gas maintains its climate benefits even at high leakage rates and regardless of time-frame considered.



Conclusion

This EDF study spends an inordinate amount of time explaining why its conclusions are plausible rather than explaining how it reached its conclusions. And it's clear why — once one digs into the report's supplemental information, it's clear that the conclusions are based on some pretty shaky assumptions and speculation that runs counter to established and/or recommended best practices for such research.

*But at the end of the day, the EDF study is not only an outlier in terms of the overall body of current methane research — it's also an outlier with regard to EDF's collective methane research, which has consistently found leakage rates between 1.2 and 1.5 percent. In the meantime, EPA **data** show oil and gas methane emissions have declined 14 percent since 1990 even as oil and natural gas production have skyrocketed. Combined with the fact that increased natural gas use has helped contribute to the best air quality of the modern era and the lowest carbon emissions in 25 years, it is clear that the shale revolution has been a win-win for the economy and environment.*

As EID described above, the EDF developed no new data; it used data from other studies. These included some of the same data from the EDF's earlier specious "Super Emitters" report. Unsurprisingly, plotting the data from this study follows the same pattern as other studies, including low production wells having a much lower final emissions point than larger wells. But, this reality does not prevent EDF from casting unwarranted allegations about low production wells.

Correspondingly, the EDF report builds its conclusions on the same flawed underlying information. Because the collected data on emissions comes from short-term, remote monitoring (drive by monitoring), it inherently means that (1) the emissions information cannot distinguish between permitted emissions like storage tank vents and equipment leaks, (2) it cannot distinguish daily emissions from short-term sporadic emissions due to maintenance activities, and (3) it is skewed toward overestimating emissions by converting these short-term measurements into daily emissions rates. The 2018 EDF Study is inaccurate and unreliable.

The EDF's biases are reflected in other aspects of its report. For example, in the report, the authors make the following observations related to "top down" data collections:

> Notably, the two largest sources of aggregate emissions in the EPA GHGI – pneumatic controllers and equipment leaks – were never observed from these aerial surveys.

A true analyst might have assessed this information and asked some probing questions. For example, if these sources were not shown as substantial emissions, could that mean that the EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks ("GHGI") emissions factors were overstating the emissions? Other studies have suggested that the EPA emissions factors for certain types of pneumatic controllers that are widely used at production sites are overestimating emissions by a factor of 100[9,10]. Various studies evaluating fugitive emissions programs have suggested that the expectations of reductions from these programs are significantly overstated[11]. Did these analysts consider the import of these data? Of course not. They noted it in passing and used the EPA GHGI emissions factors in calculating their "bottom up" site-based emissions estimates.

It is somewhat difficult to follow the convoluted path that the EDF takes to generate its excessively high emissions estimates. What is clear is that the EDF devises a series of assumptions to argue that emissions are related directly to natural gas production. At least for oil and natural gas production, this conclusion runs directly contrary to all other assessments that have shown methane emissions falling as production increases — results that are in part due to voluntary actions and in part to regulatory requirements such as Subpart OOOO.

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[9] Whitehead, Sean, New EPA Study Indicates Agency Is Greatly Exaggerating Methane Emissions, Energy In Depth (May 8, 2017), https://www.energyindepth.org/new-epa-study-indicates-agency-greatly-exaggerating-methane-emissions/

[10] Oklahoma Independent Petroleum Association, Pneumatic Controller Emissions from a Sample of 172 Production Facilities (November 2014), https://www.oipa.com/page_images/1418911081.pdf

[11] Whitehead, Seth, New Study Challenges Claim That Methane Emissions From Oil and Gas Are Higher Than EPA Estimates, Energy In Depth Climate & Environment (October 29, 2018), https://eidclimate.org/study-challenges-methane-oil-gas-epa/

This approach yields some specific, highly questionable results, including a conclusion that 26 to 30 percent of methane emissions result from natural gas and oil wells with production rates at or below 10 mcfd. This includes calculated emissions estimates derived from the mathematical assumptions in the studies for wells where no data existed. For these small wells with emissions, the EDF bases its determinations on escalating short-term data – emissions during an hour or less – into daily rates from less than 30 natural gas wells.

This EDF Study, like its predecessors, suffers from the same underlying intent. Its purpose is to distort the perception of success in understanding methane emissions and the efforts to reduce them. Its purpose is to drive new regulations — particularly regulations of low production wells, new, modified and existing. The EPA should not accept or rely upon such flawed data for making regulatory decisions.

c. Fort Worth Study data is highly questionable.

The EPA relies heavily on data from a study in Fort Worth, Texas, on wells in the Barnett Shale formation. Unlike most studies, this one was conducted with the cooperation of natural gas producers and included facility information. While the emissions data was taken by offsite mobile sampling for short time periods like the other emissions data referenced in the EDF studies, detailed production site information was provided. The EPA relies on this information to develop its Model Low Production Well. However, like all other studies, the Fort Worth study collected data broadly, capturing both low production wells and large wells. Low production wells were not specifically targeted or defined at the time of the data collection.

The EPA has now apparently extracted from the larger data base those wells with production at or below its 90 mcfd low production well threshold. It includes 25 dry gas wells and two wet gas wells. However, a closer examination of this data demonstrates key flaws. These flaws are important because the selected wells then shape the model facility. The model facility then becomes the basis for the low production well emissions estimates that then justify the requirements for the fugitive emissions program.

For example, of the 25 dry gas wells, eleven wells show no production at the time that the emissions data was taken. The consequence of including the wells with zero or less than one mcfd is the impact on the number of pieces of equipment at a site that then becomes the basis of the model facility and the basis for emissions estimates from these wells. For example, the number of valves at a site drives valve emissions which are a significant factor in the total low production model facility emissions calculations. With all 25 sites in the calculation, the EPA generates an average valve number of 108. However, if the zero and less than one mcfd wells are removed, the average valve number drops to 75. Similarly, the number of tanks per well site drops from two to one.

Better information on the nature of low production well sites is needed to assess an appropriate model well facility if a model facility is even appropriate given the diversity of production across basins.

d. Use of 1995 emissions factors raises issues of accuracy.

The EPA's use of 1995 emissions factors to develop its Model Low Production Well emissions estimates must be tested for accuracy. The 1995 effort for oil and natural gas production facilities is primarily based on an American Petroleum Institute ("API") document – API 4615 – that was prepared for generally predicting emissions levels. This is a different purpose than creating emissions factors for the purpose of regulations.

Among the key issues that bear here is whether that 1995 analysis attempted to determine distinctions between large production facilities and low production facilities. In the instant case, that distinction is significantly important because the EPA is using these factors for exactly the purpose of regulating low production wells and determining the effectiveness of its proposed program.

To present the issue in the context of its uncertainty, the emissions factor for valves – the largest component of emissions in the EPA's natural gas Model Low Production Well – is 4.5E-03 or 0.0045 kg/hr/component. The API analyzed the effectiveness of LDAR programs and compared them to EPA's assumptions in designing its LDAR program. It found that the EPA's assumptions regarding initial failure rates and the time before further maintenance or repair of equipment was necessary were inaccurate. The API data demonstrated that the EPA's assumptions overstated initial failure rates and predicted the need for further maintenance too soon. Consequently, the combination of these assumption overstates the benefits of the EPA LDAR and its cost-effectiveness. Additionally, the API's letter to the EPA submitting its information on February 22, 2018, includes updated emissions factors for component leaks at oil and natural gas production facilities. In the case of valves, the new emissions factor is 1.1E-03 or 0.0011 kg/hr/component. This factor that is 25 percent of the factor used by EPA in its Model Low Production Well.

The point here is that there are key assumptions that are highly questionable and more accurate information is essential.

3. <u>The EPA's Model Low Production Well needs improvement.</u>

The EPA creates a Model Low Production Well to define and determine the emissions and the effectiveness of its proposed low production well fugitive emissions program. The Independent Producers continue to evaluate and have certain concerns with the approach that the EPA takes in developing low production well emissions. The EPA appears to be fixated on the use of component counts to define emissions. While it is reasonable to associate the number of connections and the potential for leaks, we continue to believe that emissions from low production wells are inherently different from large production wells because of the basic physics of production and how operators change the physical equipment as production warrants.

When oil and natural gas wells are initially produced, the geologic forces that are released through the well bore drive initially higher production rates. Like releasing air from an inflated balloon, high pressure from the formation pushes flow of oil and natural gas through the well. These higher pressures and strong volumes of fluids define the design parameters for the well and the surface support equipment when the well is first drilled.

However, as wells age and production declines, conditions change. Pump jacks, if not used from the onset of production, are required to pull oil from the formation; compressors may be needed to suck natural gas from wells, while other equipment is removed or downsized. Secondary and tertiary recovery methods are used to produce more oil and natural gas from conventional formations.

These changes have consequences on the nature of emissions, particularly fugitive emissions. Like the challenge of getting the last air out of a balloon, the movement of gas molecules will follow the path of least resistance. Movement from the process equipment to the atmosphere is harder than moving to the production vessel where the flow is designed to go.

For these reasons, the Independent Producers object to relying upon component counts as the primary if not sole basis for estimating low production well emissions. Nevertheless, if the EPA intends to use component counts, we must assure that its assumptions are accurate. Based on a review of the TSD associated with the Reconsideration Rulemaking and data collection from many individual companies from various plays across the country, the Independent Producers believe the EPA continues to overestimate emissions from low producing wells.

a. The model plant is dominated by two elements – valves and storage vessels.

Because the EPA relies on component counts for its emissions estimates, it is essential to look at the mix of components and the application of emissions factors to them. The EPA divides its model facility by different types of equipment – wellheads, separators, headers, heater treaters, glycol dehydrators and storage vessels. For each type of equipment, it counts the following components – the number of specific equipment types on site, valves, connectors, open ended lines ("OELs") and pressure relief valves ("PRVs"). In reviewing the TSD, the dominant components driving the model facility plane are the number of valves and the number of storages vessels per facility. Following are the tables from the TSD for the Model Low Production Well.

Table 2-2. Average Fugitive Emissions Component Count for Low Production Well Site Model Plants

Production Equipment	Model Plant Equipment Counts	Average Component Count Per Unit of Model Plant[a]				
		Valves	Connectors	OELs	PRVs	Thief Hatches
Low Production Natural Gas Well Site Model Plant						
Wellheads	2	19.0	74.0	2.0	0.0	--
Separators	2	43.0	137.0	8.0	3.0	--
Meters/Piping	1	13.0	48.0	1.0	0.5	--
In-Line Heaters	0	0.0	0.0	0.0	0.0	--
Dehydrators	1	24.0	90.0	2.0	2.0	--
Storage Vessels	1	--	--	--	--	1.0
	Rounded Total	100.0	349.0	12.0	5.0	1.0
Low Production Oil Well Site (<300 GOR) Model Plant						
Wellheads	2	8.0	6.0	0.0	2.0	--
Separators	1	5.0	8.0	0.0	0.0	--
Headers	1	4.0	3.0	0.0	0.0	--
Heater/Treaters	1	6.0	15.0	0.0	0.0	--
Storage Vessels	1	--	--	--	--	1.0
	Rounded Total	23.0	32.0	0.0	2.0	1.0
Low Production Oil with Associated Gas Well Site (>300 GOR) Model Plant						
Wellheads	2	8.0	6.0	0.0	1.0	--
Separators	1	5.0	8.0	0.0	0.0	--
Meters/Piping	2	20.0	72.0	1.0	1.0	--
Headers	1	4.0	3.0	0.0	0.0	--
Heater/Treaters	1	6.0	15.0	0.0	0.0	--
Storage Vessels	1	--	--	--	--	1.0
	Rounded Total	44.0	105.0	1.0	3.0	1.0

a. Data Source for average component count per equipment type: EPA/GRI, CH_4 Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h). Values were multiplied by the rounded equipment count for model plant component counts.

In the most notable example above, the EPA's use of the 25 gas production facilities, with its high count for valves, drives an emission estimate that the EPA then uses to justify its formulation of a low production well fugitive emissions program. These estimates are shown below:

Model Plant Component Type	Model Plant Component Count	Uncontrolled Emissions Factor[a] (kg/hr/component)	Uncontrolled Emissions (tpy)	
			Methane[b]	VOC[c]
Low Production Gas Well Site				
Valves	100	4.5E-03	3.01	0.84
Flanges	0	3.9E-04	0.00	0.0
Connectors	349	2.0E-04	0.47	0.13
OEL	12	2.0E-03	0.16	0.05
PRV	5	8.8E-03	0.30	0.08
Thief Hatch	1	0.1296	0.87	0.24
		Total	4.80	1.34

Low Production Oil Well Site				
Valves	23	4.5E-03	0.69	0.19
Flanges	41	3.9E-04	0.11	0.03
Connectors	32	2.0E-04	0.04	0.01
OEL	0	2.0E-03	0.00	0.00
PRV	2	8.8E-03	0.12	0.03
Thief Hatch	1	0.1296	0.87	0.24
		Total	1.83	0.51

Low Production Oil Well Site w/Associated Gas				
Valves	44	4.5E-03	1.33	0.37
Control Valves	41	3.9E-04	0.11	0.03
Connectors	105	2.0E-04	0.14	0.04
OEL	1	2.0E-03	0.01	0.00
PRV	3	8.8E-03	0.18	0.05
Thief Hatch	1	0.1296	0.87	0.24
		Total	2.63	0.73

In each of these cases, the primary factors in the emissions profile are valves and thief hatches on storage vessels. If either of these factors is overstated, the impact on the cost effectiveness of the fugitive emissions regulations can be significant. As we presented above, the emissions factor for valves comes from general information on oil and natural gas production operations in the mid-1990s. Among the questions it raises are:

- Is the emission factor accurate for low production wells?
- Would the emission factor be the same for oil service and gas service?

- Do emissions vary with valve activity?

The second key component in the calculation involves an accurate assessment of the number of valves at a low production well facility. There are many factors that define the number of valves at a particular facility, obviously one being the amount of equipment at the site. Equipment changes over time as facilities respond to declining production. Different parts of the country need different equipment. For these reasons, the EPA's use of a limited number of wells – 25 to 27 wells in the Barnett Shale for natural gas production raises clear questions about whether this limited selection of wells is reflective of low production wells nationally. It creates an even more significant question in the context of a possible nationwide existing source regulatory initiative under Section 111(d) which would bring in 770,000 wells with life spans covering decades of production.

For this reason, we solicited information from oil and natural gas producers from across the nation regarding the structure of their low production facilities. This effort presents in clearer focus that attempting to use a model well facility to justify regulations falls short of the regulatory burden that EPA should bear in understanding the consequences of its actions.

b. Industry information from across the country shows different equipment counts that dispute the model well which is primarily based on the Fort Worth Study.

In response to these Comments, the Independent Producers solicited available information on component counts from low production wells across the nation. These results are not intended to be presented as statistically accurate or fully representative of the population of low production wells. However, they are illustrative of the challenge of defining a Model Low Production Well plant. We obtained information from operations in thirteen states – Arkansas, Colorado, Indiana, Kansas, Kentucky, Michigan, Montana, Nebraska, Ohio, Oklahoma, Pennsylvania, Texas, and Virginia. Information was provided on over 2,400 wells, almost 1,700 of which are natural gas wells. We defined natural gas wells as well with a gas/oil ratio of 5.0 based on BOE. Because the most questionable aspect of the EPA model well calculations relates to the assumptions related to the number of valves in natural gas operations, we will present that information here.

i. <u>Number of valves is well below model plant; wellhead assumption is too high.</u>

Following are tables from the states with reported information from natural gas sites. A first point in this information that bears on the calculations is that this natural gas low production well information shows that typical plant has one wellhead rather than the two wellheads in the EPA model plant. Inherently, this likely reduces the number of valves, but it should not be interpreted to mean that doubling the number of valves would be appropriate in the creation of a model plant with two wellheads. Moreover, it also emphasizes the burden of the Optical Gas Imaging ("OGI")-based fugitive emissions program on these smaller operations. These tables provide information on the average number of storage vessels, wellheads and valves at these natural gas production plants.

PENNSYLVANIA

The following table presents information based on 1631 natural gas well sites.

State	Number of Storage Vessels	Number of Wellheads	Number of Valves
PA	1	1	23

OKLAHOMA

The following table presents information based on 27 natural gas well sites. However, two of these sites have larger numbers of valves; 236 and 177. If those sites were removed from the total, the average number of valves would drop to 24 per wellsite.

State	Number of Storage Vessels	Number of Wellheads	Number of Valves
OK	2	1	38

OHIO

The following table presents information on 10 natural gas well sites.

State	Number of Storage Vessels	Number of Wellheads	Number of Valves
OH	10	10	22

TEXAS

The following table presents information on 10 natural gas well sites.

State	Number of Storage Vessels	Number of Wellheads	Number of Valves
TX	2	1	25

KANSAS

The following table presents information on six natural gas well sites.

State	Number of Storage Vessels	Number of Wellheads	Number of Valves
KS	1	1	11

MICHIGAN

The following table presents information on four natural gas well sites. However, one of these sites has 161 valves and 5 storage vessels. If this site was removed, the average number of valves would decrease to 17.

State	Number of Storage Vessels	Number of Wellheads	Number of Valves
MI	3	2	53

KENTUCKY

The following table presents information on two natural gas well sites.

State	Number of Storage Vessels	Number of Wellheads	Number of Valves
KY	1	1	14

VIRGINIA

The following table presents information on one natural gas wellsite.

State	Number of Storage Vessels	Number of Wellheads	Number of Valves
VA	1	1	12

c. EPA model plant calculations attribute 80 percent of low production natural gas wells to valves (63 percent) and thief hatches (18 percent) and 85 percent of low production oil wells to valves (38 percent) and thief hatches (48 percent). These calculations are based on questionable emissions factors.

Deconstructing the EPA's Model Low Production Well reveals that the primary factors in defining emissions are valves and thief hatches. This holds true for both natural gas and oil wells although valves are far more of a factor in the Model Low Production Well. The Independent Producers believe this calculation is highly questionable. As the Independent Producers have set forth above, both of the underlying assumptions on valves – the emissions factor and the number of valves – are not appropriately validated for the purpose of creating a costly regulatory program.

The valve emissions factor hinges on assumptions of the initial levels of emissions prior to the LDAR program and the recurrence of those emissions levels. Yet, the API analysis submitted to the EPA in February 2018 provides demonstrable data to produce an emissions factor approximately 25 percent of the factor the EPA used in its estimate.

Regarding the number of valves, the EPA's determination in its model facility that a low production wellsite includes 100 valves does not reflect all areas in the country that would be affected by these regulations, particularly as existing sources are affected in future regulatory actions.

i. <u>If these assumptions are incorrect, it significantly changes the cost-effectiveness assumptions of the EPA fugitive emissions program.</u>

Without addressing all of the assumptions in the EPA Model Low Production Well plant that are called into question by the additional information in the material that the Independent Producers acquired from the 13 states where we were able to get limited information, the information above on valves and the questionable emissions factor alone change the nature of the EPA's cost-effectiveness analysis.

For example, if the number of valves used for the natural gas Model Low Production Well plant is changed to 20 and the API emissions factor for valves is used to calculate the fugitive emissions program's cost-effectiveness using the EPA spreadsheet provided in the Docket[12], cost per ton of recovered methane increases by a factor of about 2.5. More tellingly, the amount of recovered methane would be estimated at 0.092 mcfd. It is hard to imagine that this miniscule amount of methane would even be detectable; it is unlikely to even be measurable as additional product.

Moreover, these calculations do not address the cost of the EPA proposed program. As we have shown earlier, past history with OGI programs has demonstrated these programs to have been far costlier than the EPA presumed. To put an additional point on it, for the Pennsylvania wells that were identified in this inventory, the operator estimates that the cost of the biennial EPA OGI fugitive emissions program would exceed $800,000 – or $400,000 per year. The average production of those wells is about 6 mcfd.

d. Assessing the cost impact on low production wells needs to look beyond the common tests of cost effectiveness in a cost per ton of reduced emissions to address the cost impact in the profitability of these small wells.

In the context of low production wells, the EPA's analysis of the cost effectiveness of its regulations, as flawed as it may be, also fails – like most cost-effectiveness analyses to address a more critical issue. Cost-effectiveness analyses typically look at the cost per unit of pollutant recovered. For low production wells, wells generally operated by small businesses, there is a remaining significant issue – whether the absolute cost can be absorbed by the operations that are regularly economically challenged.

Not surprisingly, the impact of a fugitive emissions program is significantly different between small and large wells. For the past several years, the EDF has polluted the air with an analysis that it developed showing that a variety of methane controls are cost effective when that is not the case. The EDF states these controls only cost a few cents.

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[12] Proposed_Rule_OOOOa_TSD_Section_2_-_OGI_Compressor_Model_Plant_Costs

The problem is that the EDF's analysis is flawed and, when the average low producing well produces 22 mcf per day, a few cents per mcf is highly significant. Moreover, the economic assumptions can be as significant as the emissions assumptions. In the Reconsideration Rulemaking, the EPA indicates that it uses a natural gas value of $3.42/mcf. This amount may reflect current natural gas prices at a time where storage limitations and high demand have driven prices higher. However, it fails to reflect that prices in the past several years have been well below this level. In fact, in the past two years, national natural gas prices have triggered the Marginal Well Tax Credit with the Internal Revenue Service calculating that the average price in 2016 was $2.38/mcf and in 2017 was $2.17/mcf. Moreover, producers do not receive the full value of the sales price; they must pay royalties and taxes that reduce the amount received by about 25 percent. Using the IRS average value for those two years ($2.22/mcf), the producer would then receive about $1.67/mcf for any recovered gas.

The EPA's Model Low Production Well analysis calculates that about 280 mcf/yr are emitted and 30 percent is recovered by its LDAR program – 84 mcf/yr. We believe this determination is too high, that API's emission factor is more accurate. Using the high valve count that the EPA assumes for its model well and the API emissions factor yields a recovery amount of 44 mcf/yr. It should be noted that this amount is about 0.12 mcfd and one has to raise a question of whether this amount can even be found or will show up in the daily production measurements.

Using the more realistic product prices, this presumed recovery adds about $73.50 to the annual income of the Model Low Production Well or about $36.75 to the income of a well. It is noteworthy to point out that even this small recovery may overstate the amount since it is highly dependent on the number of valves at a facility.

The larger question is what impact does this have on a low producing well. Using the cost information above, the average low producing well (22 mcfd) would receive daily income of $36.75 ($13,400 per year).

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

Consequently, the average low producing well would have to have a natural gas price in the range of $2.06/mcf to $4.93/mcf to break even. In Pennsylvania, where the average low production natural gas well produces closer to 6.0 mcfd and the typical wellsite is one well rather than two, the challenge is even greater. Income would be about $10.00/day with operating costs in the range of $12.00 to $29.00 daily. In this difficult financial situation, the application of the EPA LDAR program is a far more significant factor than the EPA has presumed in its analysis, given that the amount is essentially unmeasurable.

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

4. <u>The DOE has announced a research program to determine more accurate assessments of low production well emissions.</u>

On October 23, 2018, the DOE, Office of Fossil Energy ("FE"), announced a research program to address low production (marginal) well methane emissions. The announcement stated:

> The U.S. Department of Energy's (DOE) Office of Fossil Energy (FE) has approved an unsolicited proposal, titled *Quantification of Methane Emissions from Marginal (Small Producing) Oil and Gas Wells*, received from GSI Environmental Inc. (GSI). The data collected from well sites in basins across the United States will help address critical knowledge gaps and support best management practices that are appropriate for marginal wells.
>
> This effort complements related DOE research and analysis projects conducted by the National Energy Technology Laboratory (NETL) to improve understanding of methane emissions and identify potential reduction strategies that can improve the operational efficiency of the Nation's natural gas production and delivery systems.
>
> In June 2016, the U.S. Environmental Protection Agency (EPA) published a final rule in the Code of Federal Regulations to amend the New Source Performance Standards at subpart OOOO, and finalize new standards at subpart OOOOa to reduce methane emissions from new and modified oil and gas facilities. The updated standards included requirements for marginal well sources—oil wells that produce less than 15 barrels per day or gas wells that produce less than 90,000 cubic feet per day—which were not previously addressed.
>
> EPA's decision was based on limited data. The Agency had presumed emissions from marginal and non-marginal well sites were comparable, but that conclusion was derived from data amassed from studies employing a wide variety of technical approaches, none of which were designed to assess emissions specifically from representative populations of marginal well sites.
>
> As part of an ongoing regulatory review and reconsideration process, on September 11, 2018, EPA issued proposed targeted improvements to the 2016 standards that aim to streamline implementation, reduce duplicative EPA and state requirements, and decrease unnecessary burdens on domestic energy producers. The Agency continues to review other aspects of the 2016 rule that could be the subject of future rulemaking.
>
> While the costs of regulatory compliance impact all producers, small independent oil and gas producers who operate many of the over 700,000 marginal wells that dot the United States could be disproportionately impacted, with associated economic impacts to energy production, states, and communities.

> Recognizing these challenges, GSI proposed to collect and evaluate representative, defensible, and repeatable data from each type of well (marginal vs. non-marginal, oil vs. natural gas). This data, together with data from existing sources, will be compiled, evaluated for usability and representativeness, and analyzed to answer two key questions:
>
> - What conclusions can be reliably drawn regarding the relative methane emissions among significant marginal and non-marginal well site populations based on existing available information?
>
> - What are the key gaps in understanding the relative frequency and magnitude of emissions from marginal vs. non-marginal well sites?
>
> Once these questions are addressed, GSI will develop a focused and detailed scope of subsequent field investigations, as appropriate, to address critical data gaps. Study conclusions will also focus on identification and implementation of appropriate best management practices, so that the United States can continue to rely on traditional oil and natural gas resources for clean, secure, and affordable energy while enhancing environmental protection.[13]

This DOE study provides the EPA the opportunity to do what it should have done as it initially developed Subpart OOOOa – collect direct emissions data on low production wells. This data would allow the EPA a baseline that shows the distinctions between large wells and low production wells and the differences that may exist between types of wells and between production regions.

The EPA should embrace this DOE action.

5. <u>The EPA should make the following changes to the low production well regulations.</u>

First, the EPA should retain a low production well distinction in the regulations. Regulations designed for large high production wells do not function appropriately for low production wells averaging 2.6 B/D of oil or 22 mcfd of natural gas.

Second, the EPA should restructure the regulation to provide that as wells decline to the low production well threshold, these wells would move into the low production well requirements.

Third, the EPA should use the U.S. Tax Code definition of stripper wells as the low production well definition. Both the Tax Code definition and the proposed Subpart OOOOa definition use the same 15 B/D BOE basis. However, the Tax Code interpretation is well understood by both producers and federal regulators. Its use would prevent litigation over interpretation of the new Subpart OOOOa language. The EPA can address enforcement and compliance concerns by establishing an initial production threshold that would trigger a one-year

[13] https://www.netl.doe.gov/node/5775

period to determine whether a well is a low production well or not. The current proposal using production after 30 days does not reflect the realities of natural production declines.

Fourth, the EPA should await the results of the recently announced Department of Energy *Quantification of Methane Emissions from Marginal (Small Producing) Oil and Gas Wells* project to develop low production well regulations, if any are cost -effective or appropriate given the low emissions from low production wells. The EPA's current use of available data that was never taken with the intent of being used for low production well regulation is inappropriate. The database is too small and, more importantly, too anecdotal to be used for nationwide regulations of the diverse population of low production wells. The EPA should follow the path that it took with regard to a fugitive emissions program in the October 2016 CTG for existing oil and natural gas production facilities in ozone nonattainment areas. In that action, the EPA deferred the institution of a fugitive emissions program until an undefined future date. Given that the results of the DOE project are essential to developing sound regulations, if any are justified, this approach would be consistent with the CTG decision.

6. <u>The EPA should exempt booster compressors associated with low production wells.</u>

A forgotten but very susceptible piece of equipment often necessary for gas production from low producing wells with low pressure reservoirs is the booster compressor. There are many situations in the Appalachian Basin as well as other basins, where a booster compressor managed by small operators is necessary to move natural gas from a low pressure well or wells into higher pressure gas flow lines. Often located at or near a wellhead, these booster compressors operate with suction pressures near if not below atmospheric pressure and discharge pressures no higher than 100 psi. The Subpart OOOOa requirement for quarterly fugitive emission surveys with very expensive optical gas imaging equipment can make the use of a booster compressor uneconomical, and leave large portions of a small gas well's otherwise producible reserves in the ground. A picture of a typical booster compressor is below:

The potential to emit fugitive emissions from a booster compressor is very small. At the pressures they operate, the suction side, operating near atmospheric pressure, has little potential to leaks and the discharge side usually has no more than a fitting connecting the compressor to the flowline. Again, booster compressors have very few connections that could leak. Reciprocating compressors, even those used as booster compressors, regulated under Subpart OOOO, are already required to have the rod packing replaced every five years.

Booster compressors should be treated as wellhead equipment for low producing gas wells sufficing to have periodic audio, visual, and olfactory ("AVO") surveys that can be done by small operators, and eliminate the burdensome and expensive optical imaging surveys and recordkeeping that is typically already done at large compressor stations.

III. SUBPART OOOOa STORAGE TANK COMMENTS

A. Background/Proposal

In the reconsideration amendments, the EPA has proposed to change how operators calculate potential emissions and applicability of the storage vessel requirements under the rule. The EPA also proposes to impose additional recordkeeping and reporting requirements related to the applicability determination for both affected and non-affected storage vessels. Specifically, the EPA proposes to:

- Limit the circumstances and operational configurations operators may use to average potential emissions across a tank battery for purposes of determining applicability of a particular storage vessel.

- Revise the definition of "maximum average daily throughput" to require that operators use only the days that production is actually sent to a particular storage vessel during the 30-day evaluation period to calculate maximum average daily throughput for the storage vessel.

- Impose additional limits and criteria on what constitutes a "legally and practically enforceable limit" for purposes of determining storage vessel potential to emit ("PTE").

- Require additional recordkeeping for both affected and non-affected facilities related to storage-vessel applicability determinations.

The EPA's proposed reconsideration amendments present a number of technical and practical concerns. While the EPA claims that some of these changes are mere "clarifications," The Independent Producers have significant concerns because the EPA's proposals represent a departure from the prior EPA statements and practice and raise concerns related to retroactive application and enforcement. Accordingly, the Independent Producers provide these specific comments and suggestions on each of the above-described topics.

B. Maximum Average Daily Throughput and Averaging Emissions Across Tank Batteries.

In the proposed reconsideration amendments, the EPA expresses concern that operators have been "incorrectly averaging emissions across storage tanks in tank batteries when determining the potential for VOC emissions."[14] The EPA states that "[d]ividing an entire battery's throughput by the number of storage vessels in the battery would greatly underestimate flash emissions from the first storage vessel connected in series, which is where liquid pressure drops from separator pressure to atmospheric pressure."[15] To attempt to extend regulatory controls over these tank batteries, the EPA proposes to "clarify" how PTE is calculated for different storage-tank configurations and operations. This includes defining when it is appropriate to divide a tank battery's throughput across an entire tank battery to determine PTE for individual storage tanks for Subpart OOOOa applicability purposes. For example, the EPA states that averaging "could be appropriate" where a tank system is configured in parallel with a "splitter system" and all liquids "initially flow in equal amounts" to individual tanks, but it would not be appropriate when tanks are configured and operated with liquid product flowing in series. As a consequence, the EPA proposes including a revised definition of "maximum average daily throughput" that would specify the exact method of calculation required to determine "daily throughput for an *individual* storage vessel over the days that production is routed to that storage vessel during the 30-day evaluation period." Despite the language in the preamble to the proposal, the EPA's proposed definition appears to prohibit averaging of tank emissions in all

[14] 83 Fed. Reg. at 52,084.

[15] *Id*. at 52,085.

situations, including those under which the EPA suggests averaging may be appropriate (*e.g.*, tanks configured in parallel).

The Independent Producers disagree with the EPA's contention that under Subpart OOOOa (or its predecessor, Subpart OOOO) operators have been "incorrectly" averaging emissions across tank batteries. Subpart OOOOa currently provides that storage tank PTE "must be calculated using a generally accepted model or calculation methodology."[16] Averaging has historically been and continues to be an acceptable methodology for estimating emissions from storage tanks – particularly from tanks that are part of a controlled tank battery. The Independent Producers also disagree with the technical premise relied upon by the EPA to support its assertion that averaging is categorically inappropriate for certain tank configurations. And finally, the Independent Producers have concerns with the EPA's proposed definition of "maximum average daily throughout" as it appears to categorically prohibit averaging storage tank emissions across a tank battery and also overestimates potential emissions by relying only on the days during which throughput is actually sent to a specific storage vessel. Each of these changes directly conflict with Executive Order 13783, issued by President Trump, which directs the heads of all federal agencies to "review all existing regulations, orders, guidance documents, policies, and any other similar agency actions . . . that potentially burden the development or use of domestically produced energy resources, with particular attention to oil, natural gas, coal, and nuclear energy resources."[17] Here, the EPA proposes revisions that would significantly increase the burden on domestic producers of oil and gas.

1. **<u>The EPA's proposal to prohibit averaging of throughput across tank batteries inappropriately ignores fundamental operational processes.</u>**

The EPA's expressed concerns about averaging ignore that many new and modified tank batteries not subject to Subpart OOOOa are either: (1) already controlled pursuant to a state requirement; or (2) if uncontrolled, have a system that allows for the build-up of pressure across the head space of the entire tank battery and collection system. *See* Appendix A for examples of diagrams/drawings of sample facilities manifolded together. Though the Independent Producers believe that there is a technical basis for the EPA to allow averaging in both of these scenarios, the Independent Producers understand the EPA's concern that averaging across multiple tanks in a battery may allow certain storage tank emissions to remain uncontrolled. As a result, the Independent Producers proposed that, in order to alleviate the EPA's concern regarding uncontrolled storage tanks, while still acknowledging the technical reality of how tanks' vapors equalize across a tank battery, the EPA allow averaging (regardless of tank configuration) for all storage vessels that share a common vapor space within a controlled tank battery. The Independent Producers believe that such averaging methodologies should be allowed both for initial applicability determinations and for determinations as to whether tank vessels meet the thresholds below which the storage tank requirements in Subpart OOOOa (or Subpart OOOO) apply.

[16] 40 C.F.R. § 60.5365a(e); *id.* § 60.5430a ("*Maximum average daily throughput* means the earliest calculation of daily average throughput during the 30-day PTE evaluation period employing generally accepted methods.").

[17] 82 Fed. Reg. 16,093 (Mar. 28, 2017).

The Independent Producers wish to put a fine point on why the EPA's proposal is not technically valid, why averaging has a sound basis in engineering, and importantly, why averaging actually addresses the EPA's concern about flash emissions. Tank batteries, controlled by a common flare or combustor system or vented through one common pressure relief valve ("PRV") typically share vapor space (the tank volume above the liquid) and joint piping used to collect generated vapors and convey them to the control device. Because the vapor collection piping is typically free of restrictions, vapors flow both into and out of each tank within the battery and into overflow piping on a continuous basis, and vapors will always flow from high pressure areas to low pressure areas when flow is mechanically unrestricted. In this configuration, the flash emissions from the first tank will not be immediately emitted, but will flow into the other tanks and vent line space associated with the battery as a whole until the total pressure in the system exceeds the back-pressure of the flares, control device, or in systems without controls, the pressure relief valve. Only then will the emissions be released from either the pressure relief valve or combusted by the control equipment.

Given that gas is allowed to equalize among the tank vessels in a manifolded system, there is no technical basis for the EPA's concern about emissions from the first storage vessel in the series being underestimated. The EPA inappropriately assumes that emissions in a manifolded system are individually emitted from each tank and that they result only from the oil being produced into that given tank. In reality, for the reasons described above, the vapors being emitted from the tank battery at any point in time may have originated from any tank in the battery.

Based upon the EPA's technical approach in these proposed reconsideration amendments it may be that the EPA misunderstands how these systems typically work. For example, in the preamble to the proposed Subpart OOOO, the EPA stated: "[d]uring times of flash emissions, tanks are designed such that the flash emissions are released through a vent on the fixed roof of the tank when pressure reaches just a few ounces to prevent pressure buildup and resulting tank damage."[18] However, for facilities under the configuration described above, this individual emitting from tank thief hatches does not occur in the manner described by the EPA. Rather, vapor pressure equalizes across the system and emissions are released only when the pressure in the battery as a whole exceeds the backpressure of the PRV or the emissions proceed through the combustion device: whether emissions will or will not occur is dependent on the capacity of the entire vapor control system, not the individual storage tank. Thus, contrary to the EPA's suggestion in the proposed reconsideration amendments, dividing an entire tank battery's throughput by the number of storage vessels in the battery would be an appropriate and acceptable methodology in cases where all vessels in the tank battery share vapor space, emissions generated in one vessel equalize into the other vessels in the tank battery, and emissions are eventually controlled by the same control device or released through common PRVs. In this context, it is irrelevant whether the tanks are operated in series or in parallel, because it is not the throughput of the liquids through any single vessel within the system that determines potential emissions, but a number of other factors, including the operation of the combined vapor control system for the integrated tank battery. Accordingly, the determinant

[18] 76 Fed. Reg. 52,738, 52,764 (Aug. 23, 2011).

factor for allowed averaging across multiple storage vessels within a system is shared vapor space, rather than the EPA's proposed focus of liquid filling configuration.

2. <u>The EPA's proposal to eliminate averaging is inconsistent with recent consent decrees related to the design and operation of vapor control systems on storage tanks.</u>

The Independent Producers' technical explanation above, on how emissions are released from storage tank batteries, comports with the EPA's interpretation in recent enforcement cases. In the past several years, the EPA has entered into a number of consent decrees related to the design, and operation and maintenance of vapor control systems on storage tanks. In each of those consent decrees, the EPA acknowledges (and in fact demands) that the operator consider the vapor control system as a whole in determining how to design to avoid emissions from storage tanks. Specifically, the consent decrees typically define a vapor control system in the following manner: the system used to contain, convey, and control vapors from one or more storage tank(s) (including flashing, working, breathing, and standing losses), as well as any natural gas carry-through to storage tanks. A vapor control system includes a tank system, piping to convey vapors from a tank system to a combustion device and/or vapor recovery unit, fittings, connectors, liquid knockout vessels or vapor control piping, openings on storage tanks (such as thief hatches and any other pressure relief devices, and emission control devices). Through this definition, the EPA makes clear that it treats the vapor control system as one system, specifically a system that includes all storage vessels sharing a common vapor manifold. The EPA's proposal that prevents averaging across individual tanks even for controlled tanks and instead requires a theoretical assessment of emissions from individual tanks, even where they share a common vapor space, is entirely inconsistent with the underlying theory of the EPA's consent decrees and their treatment of vapor control systems – particularly for facilities with existing control requirements under state or permit requirements.

C. The EPA's Concern About the Amount of Storage Vessels Subject to Subpart OOOOa is Overstated and Unfounded.

As support for its position that operators have been "incorrectly averaging emissions across storage tanks," the EPA states that inspection data and compliance reports for the 2016 Subpart OOOOa indicate that operators reported "fewer than expected number of reported storage vessel affected facilities."[19] But the number of storage vessels subject to Subpart OOOOa is not in fact surprising and presents no basis for concern.

In the preamble to the proposed Subpart OOOO, the EPA clearly expressed that it originally developed the storage tank requirements because it "believe[s] it is important to control tanks with significant VOC emissions under the proposed NSPS."[20] The EPA's recently expressed concerns about the number of tanks reported under Subpart OOOOa seem to be focused on an attempted regulatory expansion with no corresponding environmental benefit. The interpretation ignores that a significant number of states already have storage tank control requirements that are similar to or even more rigorous than those presented by Subpart OOOO or

[19] 83 Fed. Reg. at 52,084.

[20] 76 Fed. Reg. at 52,763.

OOOOa. Those many programs require control of storage tanks and therefore provide operators with an enforceable limit on the VOC emissions from those storage tanks. As a result, it should be expected that facilities complying with a state control requirement would not also be subject to potentially duplicative, or even inconsistent, requirements under Subparts OOOO or OOOOa. In fact, the EPA has previously acknowledged that the focus and intent of the Subpart OOOO and OOOOa storage tank provisions was to ensure that storage tanks *not otherwise subject to state control requirements* are subject to a corresponding federal requirement to control VOC emissions.[21] The EPA's statement now, that operators reported fewer than expected storage vessels, simply means that the EPA's estimates were not entirely accurate at the forefront; a fact that is far from surprising given the complex nature of the issue.[22] In fact, even if operators followed the EPA's proposed methodology for calculating emissions from individual storage vessels, the EPA may not see as marked an increase in storage vessels subject to NSPS OOOOa as it thinks. As noted elsewhere, following the EPA's methodology for calculating emissions from individual storage tanks would potentially result in many instances where the first storage vessel in a battery is subject to Subpart OOOOa but none of the remaining storage vessels are subject. Thus, the actual number of tanks reported under Subpart OOOOa might not increase to the extent the EPA expects.

Finally, and as noted above, because these storage tank systems are controlled and function as one vapor control system, there is no basis to require companies to consider individual emissions from individual tanks as such a scenario is inconsistent with the way these facilities are operated.[23] Thus, the EPA's comment that companies have been incorrectly averaging is inaccurate and misleading. As the EPA notes in the Reconsideration Rulemaking, "[o]perators should ensure that the determination of the potential for VOC emissions reflects each storage vessel's actual configuration and operational characteristics."[24] However, the EPA fails to do exactly that when it ignores that many of these vessels share a common vapor space and either have a pressure relief valve or control device that equalizes pressure across the entire

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[21] *See* EPA Letter to Matthew Todd, 5 (Sept. 28, 2013) (acknowledging that the EPA's original estimates for the number of affected facilities under Subpart OOOO excluded facilities already subject to state emission-control requirements for storage tanks); 78 Fed. Reg. 22,126, 22,130 (Apr. 12, 2013) (subtracting from estimated number of affected facilities storage tanks in the eleven states with existing control requirements).

[22] *See, e.g.*, 78 Fed. Reg. at 22,130 (revising original Subpart OOOO estimates for storage tanks from 304 tanks per year to approximately 11,000 per year).

[23] Importantly, for controlled tank batteries, improvements to storage tank design, operation and maintenance have been adopted by operators as new information about those facilities has been identified, including through the EPA's September 2015 Compliance Alert. Though these issues are not relevant to the applicability of the storage tank requirements in Subpart OOOOa to storage vessels, these improvements render some of the EPA's historic concerns less realistic as they help ensure that emissions remain in the vapor collection system until combusted by emissions control equipment. Significant work has also been done on the functionality and operation of thief hatch and PRVs, and new thief hatch and PRV designs allow for even greater set pressures, thus accommodating higher tank vapor pressures and reducing fugitive emissions when compared to similar equipment just a few years old. The net result is an overall improvement in storage vessel vapor collection and control system operation that keeps more vapors in the system with more efficient control of the entire tank battery – especially during maximum throughput conditions – and that demonstrates a concerted effort by industry to address the concerns and issues with storage tank emissions first raised by the EPA in its September 2015 Compliance Alert.

[24] 83 Fed. Reg. at 52,085.

battery. The EPA's failure to acknowledge these key operational characteristics is particularly egregious for tanks that are already controlled.

D. The EPA's Proposal to Calculate Individual Tank Emissions Based Upon Throughput to Each Individual Tank is Technically Flawed and Overly Burdensome.

Instead of averaging throughput and emissions across a tank battery, the EPA now contends that operators should be determining throughput for each individual storage vessel. The EPA proposes two separate methods for accomplishing this feat: (1) actively measure daily throughput to each individual tank via auto-gauging or manual gauging;[25] or (2) determine for each loadout period, the highest average daily throughput for each storage vessel.[26] For the second method, where tank throughput is not monitored daily, the EPA suggests the following procedure for determining individual tank throughput: (1) measure the liquid height in the storage vessel at the start and completion of loadout of liquids from the storage vessel; and (2) divide the volumetric throughput calculated from the change in liquid height over the number of days in the production period.[27] The EPA defines a "production period" as the date "production begins to be routed to a storage vessel" until the date "throughput is routed away from that storage vessel or when a loadout occurs from that storage vessel."[28] If a tank system undergoes multiple loadouts during the thirty-day evaluation period, operators must use the maximum of the production period average daily throughput values to calculate the potential emissions from the individual storage vessel.[29]

The EPA's proposal is overly burdensome, contradicts "generally accepted" methods to calculate emissions, and ignores the technical complexity and feasibility of such an assessment. First, the EPA assumes that many operators have a readily available mechanism for determining the production within each tank on a daily basis. Equipment for determining the throughput of individual tanks is not available in all or even most instances and does not reflect a generally accepted method for evaluating production to or emissions from individual storage vessels. Whether a mechanism for determining daily production from each tank exists depends upon a number of factors, including operational configuration and commercial considerations. In most instances, there is no need to assess the production in any individual tank as liquids are not removed until the capacity of the tank battery as a whole reaches certain levels. This is particularly true at facilities that utilize lease automated control technology ("LACT") systems that automatically release liquids into a gathering pipeline upon reaching certain thresholds in the storage vessel connected to the LACT unit. Even at facilities that are loaded out by truck, there is no operational basis for allocating production from the entire battery to individual tanks.

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[25] As to this first method, the Independent Producers also want to clarify that the EPA's proposed language in the preamble that refers only to "automated gauging" generally, should be more specifically limited to scenarios where operators employ *daily* gauging (whether manual or automated). The Independent Producers stress, however, that regardless of the type of gauging employed, this should not be required on a per-tank basis.

[26] *See* 83 Fed. Reg. at 52,084.

[27] *Id.*

[28] *Id.*

[29] *Id.*

Requiring operators to undertake such granular and nuanced information for tank batteries with existing controls already in operation provides no environmental benefit and does not comport with generally accepted methods for operating these systems.

Finally, the EPA appears to assume that the emission factor will be the same for all of the production in a storage tank battery – regardless of whether the production is contained in the first tank in a series or the last. Such an assumption is inconsistent with the EPA's own statements in the preamble that the majority of flash emission potential is created due to the initial pressure drop when production is dumped from the separator to the first tank. It is also inconsistent with the technical reality that applies to these systems. Tank battery vapors are generated in three ways: thermodynamic flashing when the liquids change from higher to lower pressure; working loss when liquids flow into the storage vessel displacing vapors within the vessel; and breathing loss due to heating and cooling cycles. Under the EPA's theory, the remaining tanks in a tank battery are limited to working and breathing loss as production is transferred from one atmospheric tank to another. The reality, however, as described above, is that when tank batteries share a common vapor recovery system and control, the vapors generated by the initial pressure differential equalize across the connected vessels because the low restriction allows the vapor to flow more easily to the nearby tanks than to the distant flare(s) or combustor(s). Thus, the vapors – and emission potential – equalize throughout the entire tank battery despite being generated in the first tank receiving liquids. Accordingly, under this type of configuration, the most accurate way to determine each individual tank's PTE is to average throughput and PTE across the tank battery.

E. The EPA's Proposed Methodology Could Produce the Absurd Result that Only One Tank in a Manifolded Series of Tanks is Subject to Subpart OOOOa.

The EPA's proposal to calculate PTE based on each individual vessel in a battery could produce a situation where only one tank in a battery is subject to Subpart OOOOa. And in fact, because the emission factor for each tank in a battery reduces dramatically as production is routed to each successive vessel, the EPA's proposal makes this scenario likely: the first tank in every battery would be subject to the rule while the remainder of the battery is exempt. Under the EPA's proposed scenario, all flash gas attributable to a volume of oil or condensate would be calculated as being emitted from the first tank in series. Subsequent tanks would have no flash gas emissions because the oil or condensate will have depressurized from separator pressure to atmospheric pressure in the first tank. The only emissions from subsequent tanks in series would be due to working and breathing losses. In many cases, particularly for older batteries with lower throughput, working and breathing losses alone will not exceed the applicability threshold of 6 tons VOC per year per tank. Under this scenario, only one tank in a multi-tank battery would be subject to the requirements of Subpart OOOOa – even though the vapor control system for that battery captures and controls emissions from all the tanks in the battery. And operators would have only one tank in a battery subject to Subpart OOOOa's control, design, and recordkeeping and reporting requirements for storage vessel affected facilities, including:

- Route all emissions through a cover and closed vent system to a control device with a 95 percent destruction efficiency.[30]

- Design and certify the closed vent system to ensure "no detectable emissions."[31]

- Conduct periodic olfactory, visual and auditory inspections to ensure no detectable emissions.[32]

- Comply with all applicable recordkeeping and reporting requirements under the rule.[33]

Industry, for the sake of operational compliance, safety, and efficiency, often determines applicability on the basis of averaging throughput across all vessels in a battery when utilizing a single, manifolded collection system feeding a control device, and there is a tremendous net emissions benefit when controlling all tanks in a battery, based on throughput averaging, compared to controlling only one vessel based on individual throughput. Averaging and controlling all vessels in a battery – even if it results in the controlled VOC emissions per vessel being less than 6 tons per year – is far better environmentally than controlling only one Subpart OOOO/OOOOa applicable vessel.

It is ultimately not feasible for operators to comply with the above requirements for a *single* storage vessel. Rather, the EPA has readily admitted that if only a single storage tank in a battery were subject to the Rule, "*the owner or operator would have to vent the entire manifold to a control*."[34] Accordingly, under the guise of a "clarification," the EPA effectively proposes to require operators to control and operate an entire battery as subject to Subpart OOOOa based on the theoretical emissions of the first tank.[35] And the EPA has entirely failed to take this result into account in its estimates of the amount of affected facilities that would be subject to the rule and the cost-benefit analyses used to support the rule.

F. The EPA's Proposal to Only Include Days in Which Tanks Received Production Would Overstate Potential Emissions and Would Create an Unnecessary and Overly Burdensome Recordkeeping Requirement.

The EPA proposes that "production to a single storage vessel must be averaged over the number of days production was actually sent to that storage vessel, rather than over the entire 30 days."[36] For example, the EPA states that "if a storage vessel receives production on 22 of the 30

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[30] 40 C.F.R. §§ 60.5395a(b)(1), 60.5411a(b)-(d), 60.5412(c)-(d).

[31] *Id.* § 60.5411a(c)–(d)

[32] *Id.* § 60.5411a(c).

[33] *Id.* § 60.5411a(e).

[34] EPA, Response to Public Comments on Proposed Rule August 23, 2011 (76 Fed. Reg. 52,738), at 112–13 (emphasis added).

[35] *See* Section II.A–B, D.

[36] 83 Fed. Reg. at 52,084.

days in the evaluation then the maximum average daily throughput is calculated by averaging the daily throughput that was calculated for each of those 22 days."[37] The EPA suggests that it understands this approach would not produce a true average, but that it accurately represents *potential emissions*.[38] This is inaccurate. The EPA's proposed approach fails to account for the fact that maximum well production has a limit based on what the wells can produce, and ignores the fact that the same well production will be routed to different tanks in the battery throughout the 30-day period. In this manner, the EPA's proposal requires operators to count the same throughput multiple times for different tanks, resulting in a value greater than the actual possible total production from the wells. Thus, averaging daily throughput for each individual tank based only on the days the tank actually receives production during the 30-day evaluation period would over estimate the total amount of production that each tank could receive over a 30-day window. And when compounded across multiple tanks and extrapolated across an entire year, this approach would significantly overestimate the volume of flow to the tanks as a whole.

G. The EPA Cannot Apply its Proposed Amendments Retroactively.

Contrary to the EPA's suggestion, its proposed amendments related to storage tank applicability represent far more than a "proposed clarification."[39] Rather, the EPA's proposed amendments represent a fundamental shift in how many operators have interpreted and applied both Subparts OOOO and OOOOa; an interpretation grounded in the language of the regulation and numerous prior statements by the EPA. For this reason, if the EPA retains its proposed amendments regarding the process for determining storage tank applicability (either in part or in full), the EPA should apply the new definitions and interpretations on a prospective basis only.[40]

As a threshold matter, the EPA itself acknowledges in the proposed reconsideration amendments that it was unclear in its prior rulemakings whether operators could average emissions across a tank battery to determine applicability. Specifically, the EPA stated, "[w]hile the EPA was clear that emissions are not to be averaged over the 30-day period, *we were less clear at the time as to what averaging was allowed* when we used the term 'maximum average daily throughput.' Therefore, we propose to further clarify in this notice when and how daily production may be averaged in determining daily throughput."[41] And the rule language itself nowhere states that operators may not average emissions across a tank battery (particularly a controlled tank battery) in order to determine applicability (nor does it line up with the realities of tank batteries that share common vapor control systems, making it all the more difficult to pull this interpretation out of the rule text). The rule language states only that "[t]he potential for VOC emissions must be calculated *using a generally accepted model or calculation methodology*, based on the maximum average daily throughput determined for a 30-day

[37] *Id*.

[38] *Id.* (emphasis added)

[39] 83 Fed. Reg. at 52,085.

[40] *See Georgetown Univ. Hosp. v. Bowen*, 821 F.2d 750, 757 (D.C. Cir. 1987) (The Administrative Procedure Act "requires that legislative rules be given future effect only").

[41] 83 Fed. Reg. at 52,084 (emphasis added).

period."[42] Thus, by acknowledging that most operators have chosen to average emissions across tank batteries, the EPA is acknowledging that this is a generally accepted calculation methodology and that it was reasonable for operators to interpret the regulation in this manner.[43] Accordingly, the Independent Producers request that if the EPA retains any portion of its proposed amendments regarding the methodology for determining storage tank applicability, the EPA should make clear in the final rule that those regulatory changes apply on a prospective basis only to sources new or modified after a date certain. Of note, the proposal open for comment addresses only revisions to Subpart OOOOa and does not purport to revise the language of Subpart OOOO. However, because of the similar (and in many cases identical) nature of the language within Subparts OOOO and OOOOa, revisions to Subpart OOOOa could be interpreted to require similar application of Subpart OOOO. All of the concerns related to retroactivity of Subpart OOOOa apply equally to Subpart OOOO and present an even greater legal challenge given that Subpart OOOO is not open for revision at this time.

Limiting any adopted amendments to prospective application is particularly important in this instance because the evaluation period for many facilities potentially subject to the rule would have occurred during the first 30-day production period. Thus, to comply with the EPA's proposed change, operators would need to have records for throughput to each individual tank (not battery) for the first 30-day period of production for each storage vessel dating back to September 2015 for Subpart OOOOa and to August 2011 for Subpart OOOO.[44] Given that operators reasonably and rationally interpreted the rule to allow them to apply an averaging methodology for determining storage tank emissions, it would be unrealistic to now require operators to have the type of records the EPA enumerates in the proposed reconsideration amendments.[45] Furthermore, the EPA cannot retroactively apply the new or modified source standards to existing sources through a change in interpretation without establishing a new date after which that interpretation would apply to new and modified sources.

H. Definition of Legally and Practically Enforceable Limits.

The EPA proposes to impose additional limits on what constitutes a "legally and practically enforceable limit" for purposes of determining storage tank PTE.[46] Specifically, the EPA purports (through language in the preamble of the proposed amendments alone) to require that "any limit on capture and control efficiency from storage vessels must include sufficient

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[42] 40 C.F.R. § 60.5365a (emphasis added).

[43] *See Gen. Elec. Co. v. U.S. E.P.A.*, 53 F.3d 1324, 1329 (D.C. Cir. 1995) (noting that in determining whether a "regulated party received, or should have received, notice of the agency's interpretation," courts will look first to the plain language of the regulation).

[44] Even if the EPA were to adopt some or all of its proposed amendments to Subpart OOOOa, the Independent Producers would oppose similar revisions to Subpart OOOO. But the Independent Producers also acknowledge the reality that the EPA's proposal calls into question industry's interpretation of the relevant provisions under both rules.

[45] *See* 83 Fed. Reg. at 52,084 (describing proposed methodology for determining individual tank throughput); *id.* at 52,085 (proposed recordkeeping requirements for demonstrating applicability determination).

[46] *Id.*

monitoring to timely identify and repair emissions from storage vessels."[47] This language raises significant concerns and represents a material departure from longstanding EPA practice. Specifically, the EPA's proposal to put additional parameters on what constitutes a "legally and practically" enforceable limit: (1) conflicts with prior EPA statements during Subpart OOOO rulemakings; (2) conflicts with traditional EPA practice to defer to states to determine appropriate mechanisms for limiting PTE; (3) raises concerns about how this new interpretation/approach would apply in the Title V and New Source Review ("NSR")/Prevention of Significant Deterioration ("PSD") context where operators are relying on the same control requirements to limit their PTE; (4) raises significant concerns about retroactive application; and (5) ignores that the LDAR requirements for fugitive components under Subpart OOOOa are not tied to storage-tank applicability and apply regardless of whether a storage tank is an affected facility under the rule.

The EPA suggests that its proposal to impose additional criteria on what constitutes a legally and practically enforceable limit is grounded in the EPA's requirement that enforceable limits meet "certain enforceability criteria."[48] The Independent Producers disagree that the EPA's enforceability criteria requires the heightened standard proposed by the EPA. The EPA first announced its "enforceability criteria" in 1995.[49] The 1995 Guidance enumerates only three enforceability criteria for permit conditions: "(1) a technically accurate limitation and the portions of the source subject to the limitation; (2) the time period for the limitation (hourly, daily, monthly, annually); and (3) the method to determine compliance including appropriate monitoring, record keeping and reporting."[50] And "for rules and general permits that apply to categories of sources, the EPA established that "practical enforceability additionally requires that the provision [1] identify the categories of sources that are covered by the rule; [2] where coverage is optional, provide for notice to the permitting authority of the source's election to be covered by the rule; and [3] recognize the enforcement consequences relevant to the rule."[51] Since the EPA promulgated the 1995 Guidance, the EPA has consistently interpreted this provision to mean that state regulations that are "enforceable as a practical matter," will be considered sufficient to limit a facility's PTE.[52] This means that the permit conditions or regulations must include "monitoring, recordkeeping, and reporting requirements sufficient to enable regulators and citizens to determine whether the limit has been exceeded and, if so, to take appropriate enforcement action."[53] Here, the state regulations and permits relied upon by

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[47] *Id.*

[48] *Id.*

[49] *See* EPA, Memorandum on Options for Limiting the Potential to Emit (PTE) of a Stationary Source Under Section 112 and Title V of the Clean Air Act (Act) (Jan. 25, 1995).

[50] *Id.* at 6.

[51] *Id.*

[52] *See In the Matter of Hu Honua Bioenergy, LLC*, 2016 WL 7489673, at *20; EPA, Interim Policy on Federal Enforceability of Limitations on Potential to Emit, 3 (Jan. 22, 1996) ("[T]he term 'federally enforceable' should now be read to mean 'federally enforceable or legally and practicably enforceable by a state or local air pollution control agency.'").

[53] *Hu Honua Bioenergy, LLC*, 2016 WL 7489673, at *20 (internal quotations omitted).

industry in calculating PTE for purposes of Subpart OOOO and OOOOa more than satisfy this standard.

For example, in October 2013, following the EPA's publication of Subpart OOOO, the Colorado Department of Public Health and the Environment ("CDPHE") published internal guidance on the "Interpretation of 'Practically Enforceable' Limits for Storage Vessels Addressed under Subpart OOOO ("CDPHE Guidance"). Under the CDPHE Guidance:

> [A]n oil and gas storage vessel with an associated and properly operating flare or other commonly-recognized emission control device may take credit for the emissions reductions achieved by that control device when evaluating if the storage vessel is an "affected facility" where the control device is required through: (1) Colorado Air Quality Control Commission regulations (i.e., Regulation No. 7 Sections XII or XVII); (2) Colorado Oil and Gas Conservation Commission (COGCC) regulations; (3) Enforcement documents, such as a Compliance Order on Consent issued by an air authority such as the Division or EPA; (4) Federal regulations (*i.e.*, NSPS or MACT); or (5) Local air quality requirements or regulations.[54]

This interpretation was the correct one: all of these regulatory mechanisms require the continuous control of emissions through an emission control device and impose recordkeeping and reporting obligations on the operator to allow the agency to determine compliance. Importantly, operators relied on this regulation based on this interpretation. Similarly, relying on the EPA's consistent interpretation of "legally and practically enforceable limits," operators around the country rationally interpreted Subparts OOOO and OOOOa to allow them to account for state regulations and permit conditions requiring the control of storage tanks when calculating PTE for purposes of Subparts OOOO and OOOOa applicability. In fact, as discussed above, in the preamble to the proposed 2013 amendments to Subpart OOOO, EPA evaluated eleven states with significant oil and gas production to determine which had storage tank control requirements that operators could take into account when determining PTE: Alaska, California, Colorado, Kansas, Louisiana, Montana, North Dakota, New Mexico, Oklahoma, Texas, and Wyoming.[55] Based on its evaluation of these regulations, the EPA subtracted storage vessels in states with storage tank control requirements "from the overall count of storage vessels that would be subject to the final rule."[56] Since that evaluation, additional states have developed control requirements that appropriately establish legally and practically enforceable limits. Thus, the EPA's new approach in the proposed reconsideration amendments not only conflicts with its traditional and consistent practice; it also threatens to subject existing sources to performance standards without sufficient notice.[57]

The EPA's suggestion that existing state regulatory programs and permit conditions no longer meet the definition of "legally and practically enforceable" also casts uncertainty on other

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[54] CDPHE Guidance at 1.

[55] *See* 78 Fed. Reg. at 22,130.

[56] *Id.*

[57] *E.g.*, *Gen. Elec. Co.*, 53 F.3d at 1329.

CAA programs. Operators currently rely on the same regulations and permit conditions used to restrict PTE for Subparts OOOO and OOOOa to remain a synthetic minor under the EPA's Title V and PSD/NSR programs. The EPA's proposal thus causes confusion and casts doubt on thousands of permits under these programs around the country.

Based on the above, the Independent Producers suggest that EPA remove its proposal to impose additional parameters on enforceable limits under Subpart OOOOa and, consistent with longstanding practice, continue to defer to states to determine which of their programs satisfy the standard. However, in the alternative, if the EPA chooses to retain its proposal to redefine what constitutes an enforceable limit under Subpart OOOOa, the EPA should: (1) apply its new interpretation prospectively; (2) offer detailed guidance to operators and states on what constitutes a legally and practically enforceable limit under the rule; (3) clarify the effect of its new interpretations in regard to other CAA programs; and (4) give states sufficient time to revise their programs and permits before making this portion of the rule effective.

Finally, the Independent Producers emphasize that the EPA's concerns regarding legally and practically enforceable limits for sources potentially subject to Subpart OOOOa are unfounded because the EPA has ignored that Subpart OOOOa requires compliance with its LDAR requirements regardless of whether the requirements related to storage tanks apply. As noted above, the EPA states in the reconsideration amendments that "any limit on capture and control efficiency from storage vessels must include *sufficient monitoring to timely identify and repair emission from storage vessels* to ensure the limit on capture and control efficiency is consistently achieved."[58] Through this language, the EPA appears to be suggesting that legally and practically enforceable limits under state regulations and permits must include requirements similar to those imposed under a leak detection and repair program in order for operators to utilize the controlled PTE in determining applicability of the storage tank requirements in Subpart OOOOa. However, this suggestion ignores that the standards for storage vessels under Subpart OOOOa are focused on the installation of a control device, cover, and closed vent system to reduce VOC emissions from the storage vessel.[59] Another Section, § 60.5397a, imposes leak detection and repair requirements on the affected facility defined as "the collection of fugitive emissions components at a well site."[60] This includes all "valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to § 60.5411a, [and] *thief hatches or other openings on a controlled storage vessel not subject to § 60.5395a*."[61] In other words, storage vessels "not subject" to the control requirements of § 60.5395a – in many cases because they are subject to a corresponding state control requirement – must still implement an LDAR program for fugitive emissions under the rule. Therefore, it is entirely unclear what the EPA hopes to achieve by requiring similar requirements under state programs in order for operators to be able to take those regulations and conditions into account when calculating PTE for purposes of Subpart OOOOa.

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[58] 83 Fed. Reg. at 52,085 (emphasis added).

[59] *See* 40 C.F.R. § 60.5395a.

[60] *Id.* at § 60.5397a

[61] *Id.* at § 60.5430a (emphasis added).

I. Proposed Recordkeeping Requirements for Storage Vessels.

1. <u>The EPA's enhanced recordkeeping requirements for affected facilities are unduly burdensome and unnecessary</u>.

The EPA proposes a significant number of new recordkeeping requirements – mainly to correspond with the methodology that the EPA now proposes that operators utilize in calculating emissions from individual storage vessels.[62] As noted above in Section III.D, the EPA proposes a methodology of estimating emissions and assessing throughput to individual tanks that is inconsistent with many operators' current practices or has any technical basis. Because each of these recordkeeping requirements implicates operators' ability to generate the information required, the Independent Producers have significant concerns with the records proposed to be maintained.

Of particular note, the EPA proposes that operators document the operational configuration of the tank, including recordkeeping of the specific storage vessel that production was routed to for each day in the 30-day production period. Such a requirement indicates that the EPA fundamentally misunderstands how tank systems function and creates an overly burdensome new record requirement that operators neither maintain nor see any value in maintaining. Importantly, operational configurations of tank batteries are not static and can change (even on a day-to-day basis). The tank that first receives production one day may be the second tank to receive production the next day. Thus, it is not feasible to maintain or track each different configuration or track the days on which a specific configuration was in operation. And there is no value to doing so for controlled tanks that are manifolded together as described above.

Accordingly, consistent with the Independent Producers' Comments throughout, and in Section III.I in particular, the Independent Producers suggest that the EPA remove the proposed recordkeeping requirements to the extent they would require operators to document the operational configuration of the tank or document throughput to individual vessels in a tank battery.

2. <u>The EPA should not impose recordkeeping requirements on facilities not subject to the rule</u>.

In the Reconsideration Rulemaking, the EPA is also soliciting Comments "on specific recordkeeping requirements that would support the applicability determination for each individual storage vessel *regardless of whether that storage vessel is determined to be an affected facility*."[63] According to the EPA, "[t]his is because recordkeeping is necessary to be able to verify that rule applicability was appropriately determined in accordance with the regulatory requirements."[64] Such an approach is entirely inconsistent with traditional NSPS requirements. Operators are required to determine compliance with an NSPS. Operators, upon

[62] *See* 83 Fed. Reg. at 52,085.

[63] 83 Fed. Reg. at 52,085 (emphasis added).

[64] *Id.*

request and in certain circumstances, may be required to demonstrate the basis for their conclusion that a facility is not subject to an NSPS. Operators perform this assessment in some way, shape, or form for every NSPS. However, the NSPS itself – which is only applicable to affected facilities – should not in this one case have an independent recordkeeping requirement applicable to non-affected facilities.[65]

The EPA's proposed amendment could create confusion and raises significant enforcement concerns. Operators will typically look first to the applicability section of an NSPS, and if it is determined that a specific facility is not subject to the rule, they look no further (*e.g.*, into the recordkeeping sections applicable only to affected facilities).

Finally, the EPA's proposal raises concerns about the potential for retroactive application (as discussed in further detail above). The EPA says that it is clarifying a rule that has been in existence for years, but is apparently expecting operators to have records that would demonstrate compliance now with the EPA's new interpretation. At a minimum, if the EPA includes recordkeeping for non-affected facilities (which the Independent Producers believe it should not), then the EPA should clarify in the final rule that this new recordkeeping requirement will apply only on a prospective basis.

IV. AMEL – EMERGING TECHNOLOGY

America is on the cusp of new breakthroughs that can bring dramatic improvements to air quality at lower cost. OGI was an important step toward lower emissions, but far from the last step. Less expensive and more effective monitoring technologies will accelerate the production of clean domestic energy, helping to deliver a healthy environment and a healthy economy. The EPA must revise the AMEL provisions of Subpart OOOOa to unlock the benefits of these emerging technologies.

A. The Independent Producers Support the Options in the Proposed Rule to Use Modeling, to Test Technologies in a Controlled Test Environment, and to Allow Manufacturers/Vendors to Apply for Approvals.

1. Modeling

Independent Producers strongly support the inclusion of modeling, in addition to limited field data, to demonstrate the performance of a specific technology. This is a preferred and recommended option to the onerous requirement to gather 12 months of field data. The 2018 Interstate Technology and Regulatory Council ("ITRC") paper states, "Computer modeling is highly valuable for evaluating emission reduction objectives due to the probabilistic nature of emission rates."[66] The paper also states, that "computer-based modeling, coupled with empirical

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[65] *See* 40 C.F.R. § 60.1(a) ("[T]he provisions of this part apply to the owner or operator of any stationary source which contains an affected facility.").

[66] Interstate Technology and Regulatory Council ("ITRC"). 2018. Evaluation of Innovative Methane Detection Technologies. Section 5.2 Design Elements. Methane-1. Washington D.C.: Interstate Technology and Regulatory Council, Methane team. https://methane-1.itrcweb.org

validation of model accuracy, is a potential solution to rigorously evaluate application efficacy under the most likely encountered meteorological and site conditions. [67] The Fugitive Emissions Abatement Simulation Toolkit ("FEAST") model is a virtual gas field simulator that predicts emission reductions of various leak detection and repair programs. An effective demonstration of equivalency could include an empirical evaluation of an application at a structurally complex site such as a gathering compressor station over a time period such as twelve months that assesses performance under a wide range of meteorological conditions. If a computer model can accurately predict the detection limit and response time for different sources as a function of environmental parameters, then a probabilistic model can be used to simulate performance at other sites. This approach could allow a scientifically rigorous determination of equivalency while minimizing the number of sites required for field testing."[68] Additionally, modeling is highly valuable in that it allows for comparison of the "end game" of equivalent emissions reductions, *i.e.* allows for comparison of two approaches/work practices rather than specific technology detection thresholds.

Further, the EPA used modeled simulations when they simulated the frequency and work practice to detect leaks from equipment ("OGI AWP").[69] The EPA used a Monte Carlo model to evaluate and approve the use of OGI as an alternative work practice ("AWP") for fugitive emissions monitoring.[70] "In developing the AWP, the EPA sought to design a program for using the optical gas imaging instrument that would provide for emissions reductions of leaking equipment at least as equivalent as the current work practice. To do so, we used the Monte Carlo model for determining what leak rate definition and what monitoring frequency were necessary for the AWP."[71] At no point in its approval of OGI did the EPA require site-specific modeling.

We strongly urge the EPA to apply the same logic to AMEL equivalence demonstrations. There is no reason why rigorous statistical modeling, combined with real-world field data and thorough documentation and recordkeeping, should not be sufficient for EPA to make a reasoned decision on broadly approving a new technology.

a. Controlled test environment.

Use of a controlled test environment, such as Colorado State University's Methane Emissions Technology Evaluation Centre ("METEC") to gather field data on the performance of various leak detection technologies and compare their capabilities to current approved methods, such as OGI, would greatly streamline the process of determining equivalence, as well as the lengthy CAA Section 111(h) application and approval process. The Independent Producers appreciate the EPA including this option in the proposal and further recommends that a facility such as METEC be recognized by the EPA as a facility where all suitable technologies could be tested for equivalency. The team METEC is currently working to establish a baseline for OGI for this very purpose. In fact, the EPA has funded work at METEC toward developing the

[67] *Id.*

[68] *Id.*

[69] Alternative Work Practice to Detect Leaks from Equipment Final Rule, 73 Fed. Reg. 78201 (add date)

[70] 73 Fed. Reg. at 78,201.

[71] *Id.*

baseline for OGI. Testing a new technology against a clear established baseline and following a pre-set methodology for testing would provide consistency and confidence in the process. If manufacturers are aware of the baseline emissions reduction for OGI they would clearly know how their technology must be utilized in an LDAR program to be deemed equivalent. As a result this would streamline the process and allow new technologies to successfully navigate this application and approval process and be deployed faster which, in turn, would result in reducing fugitive emissions faster.

The ITRC paper referenced above supports this concept and states:

> [c]ontrolled releases under field conditions are ideal for systems with emission source objectives because they can assess the accuracy of source quantification and/or localization under realistic meteorological conditions. Long-term testing at field sites allows controlled releases to be tested under a diversity of meteorological conditions. Performing multiple controlled releases under each set of conditions can be used to calculate the probability of detection as a function of emission rates and other relevant conditions such as wind speed.[72]

Therefore, gathering field data at a facility such as METEC would prove extremely useful and could effectively take the place of gathering field data at an active oil and gas well site. The API recommends that testing technologies in a controlled test environment, in addition to modeling, will greatly minimize the field data necessary in order to demonstrate the performance of various technologies and achieve approvals.

b. Vendors/manufacturers as applicants for approval of emerging technology.

Vendors/manufacturers of new leak detection technologies are the experts in this advanced, high tech area and are the appropriate person(s) to apply for approval of a technology to be used in compliance with Subpart OOOOa for methane and/or VOC leak detection and Independent Producers appreciates the inclusion of this language in the proposal.

However, the Independent Producers recommend that the operator <u>not</u> be required to be a party to the application and approval process as well. Although the manufacturer/vendor may need to coordinate with an operator to test their technology in the field and obtain data, oil and gas operators are not in the business of, nor are they likely to have the bandwidth, to develop, test, and obtain approvals for methane leak detection technologies.

B. The EPA Should Allow for <u>Basin-Wide</u> Approvals of Emerging Technology for Use in Complying with the Leak Detection Requirements in the Rule

One of the Independent Producers' priority concerns in the proposed Reconsideration Rulemaking is the requirement to apply for the use of emerging technologies on a site-specific level. Outlined below are the technical and legal reasons why this would be an enormous unnecessary burden, not feasible to undertake from an administrative and timing perspective, not effective at showing equivalence to the current method, and will greatly stifle innovation in this

[72] *Id.*

very dynamic area of technological advancement. Numerous technologies are currently being developed and piloted at oil and gas field sites throughout the country. Many of these state of the art technologies in development can detect leaks faster and more efficiently which will enable the operators to make timely repairs resulting in less fugitive emissions, resulting in a win-win for both the operator and the environment. This recommendation has broad support from environmental groups as well as industry.

1. **Site specific variables can be addressed in conditions required for the use of the technology.**

In the proposal, the EPA states that "we are not changing the requirement that AMEL's be site-specific because we are aware of the variability of this sector and are concerned that the procedures may need to be adjusted based on site-specific conditions (*e.g.*, gas compositions, allowable emission or landscape).[73] There is no logic behind this statement and this reasoning does not withstand scrutiny. First, if a technology is designed to measure methane molecules in the atmosphere, it will measure methane molecules in the atmosphere, plain and simple. It does not matter what the site looks like or what the gas composition is. If there is methane above a certain concentration, the technology should find it; if there is not, it will not.

Further, the EPA can establish clear and consistent parameters under which a technology will be able to detect methane emissions. The approval of the technology could have certain conditions assigned to it that are required to be met in order for the technology to be used at a site, similar to the EPA's technology-based approval for OGI that had minimum/maximum temperatures and minimum/maximum distance parameters required to be present, for example.

Continuous sensors, for example, allow for continuously monitoring a site for leaks and particularly suited for intermittent leaks at very low thresholds. Day or night time is immaterial for detection by continuous sensors. On the other hand, aerial based surveys might have limitations flying at night and may use sunlight as reference and would need to be deployed only during the daytime.

In response to the EPA's mention of landscaping being a site-specific variable, if the landscaping at a particular site is not conducive to the technology employed (*i.e.*, impedes the pathway of the technology to effectively operate, for example) then the technology may not be used at that site. Parameters are required to be met for the proper operation of the specific technology, plain and simple. Again, this could be a condition for the use of a specific technology at a specific site.

In response to the EPA's mention of allowable emissions being a site specific variable, this is completely irrelevant to the case for a site specific approval. Every site has allowable emissions such as some venting that is allowed if under threshold levels. Differentiating allowable venting, for example, from fugitive emissions leaks could arguable be an issue against the approval of any technology but that should not be a reason to disallow approval on a basin-wide level and stifle all development in this important area. An approach where detection may be impacted by allowable emissions may be an approach that is used to direct inspection efforts.

[73] Subpart OOOOa Proposed Technical Revisions, 83 Fed. Reg. at 52,080 (October 15, 2018)

Some technologies could be used as a frequent screening tool and may require the operator visit the site with OGI for example to detect the source of the leak(s). But it would flag the large emitter sites and again, enable the operator to find and fix the largest leaks faster.

In the OGI AWP final rule, the EPA stated, "the standard is an alternative to the existing work practice and maybe used in place of the existing work practice <u>where feasible</u> and whenever the owner or operator chooses to do so."[74] As this language clearly states, OGI received a blanket approval from the EPA but if a particular site did not meet the conditions, then the technology was deemed not feasible that site at that time. Often, Independent Producers' member companies' camera operators determine that they cannot take an accurate OGI survey due to meteorological conditions and they return later when the conditions are within the prescribed OGI parameters.

2. <u>Basin-wide data is necessary to determine equivalency and receive approval per Clean Air Act 111(h).</u>

The technologies being developed have different methane sensitivity thresholds and can operate at different frequencies. For example a spectrometer (*i.e.*, laser based technology) mounted on an airplane can scan over an entire basin in days. It could do these fly-overs more quickly and efficiently than a person using a hand held OGI camera on foot at a site and therefore, could have a higher frequency assigned to it and this would be a feasible alternative. The cost benefit analysis of some of these emerging technologies have been shown to be favorable and a preferred option for some member operators.

In the OGI AWP, the EPA states, "[t]he emission control effectiveness of any work practice is a function of both 1) <u>its ability to detect leakage and</u> 2) <u>the frequency of monitoring</u>. An equivalent work practice may require more frequent monitoring, depending on its mass rate threshold for detecting leaks."[75]

If the fly-over technology has a lower sensitivity threshold, it may only find larger leaks, but it could find these larger leaks faster with a more frequent monitoring schedule.

The EPA further states, "[a] more frequent monitoring requirement becomes necessary because higher mass emission reductions from large leaks, found earlier, are offset by some degree by smaller leaks which go undetected."[76] Equivalency in Section 111(h)(3) is discussed simply as "a reduction in emissions of any air pollutant at least equivalent to the reduction in emissions of such air pollutant [under the current work practice]."[77] Based on this standard in

[74] Alternative Work Practice to Detect Leaks from Equipment Final Rule, 73 Fed. Reg. at 78,204 (Dec. 22, 2008). (emphasis added)

[75] Alternative Work Practice to Detect Leaks from Equipment Proposed Rule, 71 Fed. Reg. at 17,404 (Oct. 18, 2008).

[76] *Id.*

[77] 42 U.S.C. § 7411(h)(3).

the statute, larger leaks found earlier and more frequently should reasonably be able to offset smaller leaks that may not be found as timely.

Further, in referring to OGI in the AWP final rule, the EPA stated, "[t]he results show that the AWP will achieve the *EPA's goal of detecting leaking equipment from which the majority of emissions arise."*[78]

Therefore, similar to the EPA's approach in the AWP OGI rulemaking, the EPA should focus on basin-wide (or category-wide) mitigation equivalence, not detection equivalence. For example, a one-time aerial-based survey may not be able to detect emissions with the same sensitivity as ground-based technologies, or detection equivalence, but conducting multiple surveys instead of one would mean that any potential fat-tail emission sources are identified faster than a ground-based method. That means more frequent monitoring may provide mitigation equivalence. Mitigation equivalence can only be achieved across many sites, because of the relatively few sites that produce the bulk of emissions. Further, basin-wide approaches are likely to be more accurate in terms of estimating total emission reductions than individual site estimates, given the high variability in individual site emissions. The emission reductions at any given site may differ greatly, but averaged across thousands of sites, the EPA will be able to understand emission reductions with greater confidence.

The EPA can use statistical models such as FEAST to make data-driven decisions about equivalence. The EPA can then incorporate basin-specific emissions data into modeling to ensure that its emission reduction objectives are being met. Making decisions based on aggregated data reduces the uncertainty that comes with site-specific estimates.

In addition, Independent Producers recommend that the site attributes could be obtained from a small number of <u>representative sites</u> in the basin; then that data, coupled with modeling and testing in a controlled test environment would be adequate to determine if equivalency is achieved.

Further, once a technology is approved to be used in a specific basin, <u>all subsequent sites drilled and constructed in that basin going forward</u> will have the opportunity to use that technology, without going through the onerous Section 111(h) application and, approval process for each new site, or groups of new sites all over again. Again, this is not feasible and would stifle development of leak detection technologies.

Therefore, based on this information and the EPA's logic in this previous OGI AWP rulemaking, a basin wide survey is necessary to have a data set that can be deemed equivalent. And once this technology has been deemed equivalent based on emissions reductions achieved in a specific basin, use of the technology in that basin should be the subject of the application for approval. As explained above, the approval could be granted with conditions that would need to be met at each site prior to the technology being used.

[78] Alternative Work Practice to Detect Leaks from Equipment Final Rule, 73 Fed. Reg. at 78203 (December 22, 2008)

3. <u>Common sense dictates basin-level approval.</u>

CAA Section 111(h) requires that an alternative work practice must first be shown to be equivalent, then be subject to a notice and comment period, and possible public hearing. Gathering the field data and performing modeling, and showing equivalence will be a lengthy process, of at least a year of more. Then the notice and comment period will take months; EPA stated in the Subpart OOOOa final rule that they would make a decision within 6 months of close of the comment period.[79] Therefore, realistically, this process would take approximately two years. To do this for every single well site, such as a well or wells on a pad or a centralized tank battery would be ludicrous. Neither the regulated community nor the EPA can manage the crush of applications that will be necessary to adopt new technologies through site-specific approval. It would be outrageously lengthy and absolutely no vendor/manufacturer or operator would undertake this fruitless effort.

One of the Independent Producers member company's operations in the Permian Basin in Texas reported 273 well sites subject to Subpart OOOOa LDAR monitoring for 2018. Going through this Section 111(h) process for each of these sites would take <u>546 years</u>. And then all over again for the subsequent wells this operator is drilling in the Permian Basin every month (with about 3 wells/pad or well site) and building around 4-6 large centralized tank batteries per year that would also require site-specific approval per the current language in the rule.

Common sense clearly dictates that the EPA reconsider this site-specific approach and approve a basin-wide (or category-wide) approach. Not doing so would stifle innovation in this technologically advanced, dynamic area. The environment would be the loser for the life of this rule if EPA allows only handheld OGI cameras or Method 21, both of which will be outdated technologies in a few years, to detect leaks in compliance with Subpart OOOOa.

4. <u>CAA Sec. 111(h)(3) does not constrain basin-wide approvals.</u>

The EPA should provide a procedure for approving an AMEL under Subpart OOOOa for categories of sources, rather than limit an AMEL to an inefficient and unworkable source-by-source application. The structure and language of Section 111 and EPA's decision to allow for similar flexibilities under other CAA provisions confirm that applying an AMEL to source categories is appropriate and lawful.

Section 111 calls on the Administrator to list "categories of stationary sources" that "cause[], or contribute[] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare."[80] The Act then calls on the Administrator to promulgate and subsequently revise every eight years, if appropriate, "standards of performance for new sources within such source category."[81] The Act defines a standard of performance for purposes of Section 111 as:

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[79] Subpart OOOOa Final Rule, 81 Fed. Reg. at 35,861 (June 3, 2016)

[80] 42 U.S.C. § 7411(b)(1)(A).

[81] *Id*. § 7411(b)(1)(B).

> 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.[82]

In the event it is not feasible to establish such a standard, Section 111(h)(1) authorizes the Administrator instead to "promulgate a design, equipment, work practice, or operational standard, or combination thereof."[83] Section 111(h)(1) does not refer to categories of sources or individual sources, but because a Section 111(h) standard is intended to replace a standard of performance applicable to an entire source category, the logical inference is that Section 111(h) standards also apply to source categories. Section 111(h)(3) provides for an AMEL when:

> after notice and opportunity for public hearing, any person establishes to the satisfaction of the Administrator that an [AMEL] will achieve a reduction in emissions of any air pollutant at least equivalent to the reduction in emissions of such air pollutant achieved under the requirements of [section 111(h)(1)].[84]

On the face of this language, because any AMEL will serve as a replacement for a category-wide 111(h)(1) standard, any demonstration that an AMEL will achieve an emission reduction at least equivalent to a 111(h)(1) standard could reasonably be made on a category-wide basis and be applied to an entire source category.

Section 111(h)(3) also states, however, that once a successful equivalency demonstration has been made, "the Administrator shall permit the use of such alternative by the source for purposes of compliance with this section with respect to such pollutant."[85] This provision's authorization of source-specific AMEL applications should not be interpreted to preclude the EPA's authorization of an AMEL on a source category-wide basis. Indeed, provided an adequate demonstration for a single source within a source category can be made and it can be established that there are no material differences between that source and the other sources in the category that would render the AMEL less than equivalent to a Section 11(h)(1) standard, there is no reason based on the statute to prohibit category-wide application of AMEL. Indeed, any other number of approaches, including a more generalized approach that does not focus on individual sources, for making an adequate category-wide demonstration under Section 111(h)(3) may be available, and EPA should evaluate them on a case-by-case basis.

Allowing for source category-wide AMEL determinations would be consistent not only with the overall structure of Section 111 and its focus on category-wide standards under Sections 111(b) and 111(h)(1); it is also consistent with the limitation prohibiting the EPA from imposing

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[82] *Id*. § 7411(a)(1).

[83] Id. § 7411(h)(1).

[84] *Id*. § 7411(h)(3).

[85] *Id*.

specific technological emission reduction requirements pursuant to section 111. Section 111(b)(5) states:

> Except as otherwise authorized under subsection (h) …, nothing in this section shall be construed to require, or to authorize the Administrator to require, any new or modified source to install and operate any particular technological system of continuous emission reduction to comply with any new source standard of performance.[86]

Section 111(h)(1) allows the EPA, under limited circumstances, to impose a standard "which reflects the best technological system of continuous emission reduction." Section 111(h)(3) serves as a safety valve on that authority and thereby functions to further the policy set out in Section 111(b)(5). To give full effect to that policy, the EPA should allow for category-wide AMEL demonstrations.

Adopting such an interpretation for Section 111(h)(3) would also be consistent with the policy EPA has adopted for the nearly identical provision in Section 112(h)(3), which authorizes an AMEL under the provisions of the CAA governing national emission standards for hazardous air pollutants. The EPA's regulation implementing Section 112(h)(3) recognizes that the EPA is authorized to approve an AMEL for "source(s) *or category(ies) of sources* on which the alternative means will achieve equivalent emission reductions."[87] Given the similarities between the programs authorized under Section 111 and Section 112 and, in particular, the similarity of Section 111(h)(3) and 112(h)(3), the EPA should adopt its policy of applying an AMEL to source categories for Section 111(h)(3) in the same manner as it has done with respect to Section 112(h)(3).

Moreover, the EPA has adopted similarly flexible approaches under other provisions of the CAA. For example, under the Act's visibility provisions, the EPA must require states to include in their state implementation plans measures reflecting "best available retrofit technology" ("BART") for certain "major stationary sources."[88] The Act further states that BART must control emissions "from such source," and defines BART as taking into account, among other things, "any existing pollution control technology in use at the source" and "the remaining useful life of the source."[89] Despite the focus of the statutory language on determinations for individual sources, the EPA's rules allow the EPA and the states to authorize BART alternatives that can apply to groups of sources and that allow emission averaging across sources, even over wide regions, in lieu of imposing source-specific emission limits or source-specific alternatives to such limits.[90] The courts have consistently affirmed the authority of the EPA and the states in this regard.[91] If alternatives to emission limits (or work practice standards)

[86] *Id*. § 7411(b)(5).

[87] 40 C.F.R. § 61.12 (emphasis added).

[88] 42 U.S.C. § 7491(b)(2)(A).

[89] *Id*. § 7491(b)(2)(A), (g)(2).

[90] 40 C.F.R. § 51.208(e)(2).

[91] *See, e.g.*, *Util. Air Regulatory Grp. v. EPA*, 471 F.3d 1333 (D.C. Cir. 2006); *Central Ariz. Water Conserv. Distr. v. EPA*, 990 F.2d 1531 (9th Cir. 1993).

for groups of sources under these provisions are permissible despite the continued references to the term "source," then surely a source category-wide AMEL is permissible under Section 111(h)(3).

In regard to frequency specifically, there is no legal impediment to demonstrating that an AMEL is equivalent to a Section 111(h)(1) standard based on differences between the AMEL and the standard against which it is being evaluated – such as differences in the frequency (*e.g.*, annual, semi-annual, quarterly) over which the monitoring or other requirements must occur. The current regulations for implementing Subpart OOOOa state that the EPA "may condition permission [to use an AMEL] on requirements related to the operation and maintenance of the alternative means."[92] Such requirements could easily include frequency of the deployment or operation of the AMEL.

V. <u>AMEL – STATE EQUIVALENCY</u>

A. The EPA Should Recognize the Approved State Programs as Wholly Equivalent to Subpart OOOOa LDAR Program and Fully Delegate the Implementation of the LDAR Monitoring Provisions to These Respective States.

Based on the EPA's state LDAR program equivalency guidance document provided with this rulemaking, the EPA explained that they analyzed the sensitivity thresholds and monitoring frequencies of approved technologies in a number of state programs, as well as other program requirements and, based on all of these variables combined, deemed these various state programs equivalent to Subpart OOOOa LDAR program.[93] However, the EPA is requiring operators to use the fugitive emission component definition from Subpart OOOOa, in addition to the reporting and monitoring plan. Many Independent Producers members are required to comply with state permit requirements and therefore, are currently implementing both the state and federal LDAR programs concurrently and the differing required recordkeeping and reporting requirements, as well as Subpart OOOOa's monitoring plan. This is a very burdensome duplicative administrative burden with no added benefit for the environment.

Under the well-established premise of cooperative federalism, the EPA should recognize these programs in full, including the states' recordkeeping and reporting requirements. The states have recordkeeping and reporting to ensure compliance with their programs and the EPA should give proper deference to states for compliance assurance for their state program. If the state program is not adequate in the EPA's opinion, then the EPA needs to address this issue with the states.

Complying with two different recordkeeping and reporting schemes on the same site(s) is an enormous administrative burden with no added environmental benefit. And requiring the federal reporting (which would require some Subpart OOOOa recordkeeping requirements to be

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[92] 40 C.F.R. § 60.5398a(a).

[93] EPA's Memo. *Equivalency of State Fugitive Emissions Program for Well Sites and Compressor Stations to Proposed Standards at 40 CRF Part 60, Subpart OOOOa* (April 12, 2018).

met in order to comply with the federal reporting), and monitoring plan defeats the purpose and any benefit from the EPA approving these state programs in the first place.

Cooperative federalism is a central tenet of the CAA. Over the course of its fifty year history, the Act has evolved first from a set of general principles intended to guide States as they undertook regulation of air pollution sources, to an extensive number of more targeted standards often prescribed by the federal government in the first instance and then implemented by the states. The principle that the States and the federal government will work in tandem to protect the nation's air resources is embodied throughout the Act. Congress, in Section 101(a)(3) of the Act, declared air pollution control to be "the primary responsibility of States and local governments,"[94] with the federal government providing "financial assistance and leadership."[95]

For example, pursuant to Section 110 of the CAA, while the EPA develops the national ambient air quality standards,[96] states develop plans, called state implementation plans, to meet those standards. In that context, the U.S. Supreme Court has made clear that "[t]he Act gives the Agency no authority to question the wisdom of a State's choices of emission limitations if they are part of a plan which satisfies the standards."[97] Similarly, under the CAA's visibility provisions, states have broad leeway to develop plans to combat regional haze that the EPA cannot second-guess if the states have considered the statutory factors.[98]

Section 111, the provision at issue here, fits squarely within the cooperative federalism tradition, with section 111(c) expressly calling on states to develop "a procedure for implementing and enforcing standards of performance for new sources" and calling on the Administrator to delegate "any authority he has … to implement and enforce such standards."[99] The Supreme Court has affirmed that these cooperative principles are the heart of the CAA again and again.[100]

State LDAR programs are precisely the sort of regulation over which states have special expertise, and they are proper subjects of state control.

VI. RECORDKEEPING AND REPORTING REQUIREMENTS

The Independent Producers appreciate the changes the EPA has made to the Subpart OOOOa recordkeeping and reporting requirements, but we continue to believe further streamlining is necessary to reduce financial burden to operators, especially in those situations

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[94] 42 U.S.C. § 7401(a)(3),

[95] i*d*. § 7401(a)(4).

[96] *see* 42 U.S.C. §§ 7408, 7409,

[97] *Train v. Natural Res. Def. Council, Inc.*, 421 U.S. 60, 79 (1975).

[98] *Am. Corn Growers Ass'n v. EPA*, 291 F.3d 1, 8 (D.C. Cir. 2002).

[99] 42 U.S.C. § 7411(c)(1).

[100] *See, e.g.*, *Whitman v. Am. Trucking Ass'ns*, 531 U.S. 457, 470 (2001) ("It is to the States that the CAA assigns initial and primary responsibility for deciding what emissions reductions will be required from which sources."); *Union Elec. Co. v. EPA*, 427 U.S. 246, 269 (1976) ("Congress plainly left with the States, so long as the [NAAQS] were met, the power to determine which sources would be burdened by regulation and to what extent.").

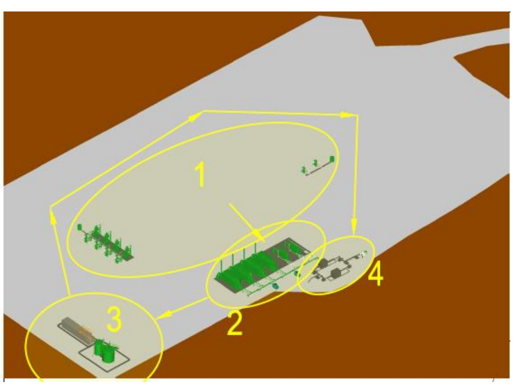
where the requirements do not enable the Agency to determine compliance. In these instances, we maintain that the increased financial burden caused by the excessive reporting and recordkeeping is unjustifiable. The Independent Producers believe further reductions and streamlining to the recordkeeping and reporting requirements are essential to the creation of an effective rule.

A. Well Completions

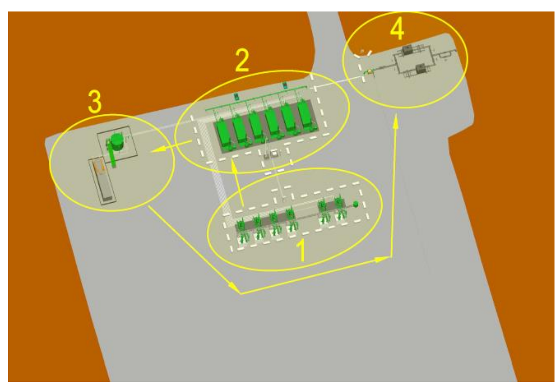
Section 60.5420a(b)(2) lists recordkeeping and reporting requirements for flowback routed through *permanent* separators. However, the presence of a permanent separator that was installed and operated from the onset would technically indicate that the flowback process never actually occurred making any recordkeeping and reporting requirements in these situations unnecessary and overly burdensome. The presence of a permanent separator indicates production has begun. The lack of a temporary separator and the absence of flaring and/or venting to accommodate emissions during flowback eliminates the necessity for any type of recordkeeping and reporting beyond simply acknowledging that the well went directly into production and no flowback occurred at that location.

B. Observation Path

It is most typical that the engineering footprint of equipment at a well site remains the same from site to site as the operating process does not change. This is most particular for well sites within the same basin. To that extent, it is rather redundant to require an observation path depicting the footpath of the surveyor when the inspection would necessarily follow to process flow of the equipment in order to capture all the potential leaks. For example, below are the actual Observation Paths of two independent well sites with the same process flow. As depicted, the footpath of the surveyor always follow the same sequence in terms of the process equipment.



Well Site A



Well Site B

In lieu of maintaining an Observation Path and Site Map for every well site, we would propose a description be included in the company's Monitoring Plan instructing the surveyor to follow the process flow. An example is as follows:

Perform an inspection of the following equipment in the sequence as follows: Well heads → Separators → Tanks → meter area. For each equipment, perform a 360 degrees inspection before proceeding to the next.

For Example - In Lieu of an observation path, we propose a description of how each "type" of equipment will be monitored via a description and location of each component being monitored.

C. Pneumatic Pumps

We recommend removing all recordkeeping and reporting requirements associated with the inspection of covers as referenced in §60.5416a(a). Covers are unique to storage vessels and have no reason to be listed in pump requirements.

D. Low Production Wells (Wildcat Wells, Delineation Wells, Low Pressure Wells, and Wells with GOR less than 300 scf/bbl)

The EPA continually fails to consider the massive financial, resource allocation, and administrative impacts resulting from the excessive amount of prescriptive requirements assigned to production facilities. What is more distressing is that these overly burdensome requirements are applied to all facilities independent of the level of production. The EPA seems to consider minor source production facilities on a level playing field with refineries and infinitely more complex operations that have thousands more components than even the largest applicable sources covered by this rule. The Independent Producers understand low production source (< 15 BOE) exemptions are being reconsidered [101] and urge The EPA to follow through with such an exemption, specifically concerning LDAR requirements and the associated recordkeeping and reporting. High volume recordkeeping, on par with large refineries, is not necessary and completely unjustified for these diminutive, financially sensitive sources.

E. Storage Tanks

The EPA is soliciting comments on the type of records necessary to ensure proper calculation of VOC emissions and maximum daily average (*i.e.*, daily measurements, liquid height measurements, start and end dates for each production period, number of days production was routed to a particular storage vessel, load slips when automated readings are unavailable, documentation of the operational configuration of the tank/tank battery, etc.). The EPA is also seeking comment on the perceived recordkeeping burden to operators.

It is unclear how the newly proposed maximum daily average calculations will help control, or reduce, emissions from storage vessel affected facilities, especially with respect to controlled tanks and/or tanks that are manifolded together. Consequently, the increased recordkeeping and reporting requirements that accompany this proposal are overly burdensome and without environmental benefit. Any increased recordkeeping and reporting requirements that result from disallowing emissions averaging over the entire tank batteries that share a common control device, or vent, are unnecessary. Furthermore, it is unclear if operators, especially small operators, even have the capability to monitor and record individual storage

[101] *See* Docket ID No. EPA-HQ-OAR-2010-0505-7730.

vessel throughputs as described in the EPA's proposed scenarios. Tank unloading operations are tracked by the total volume of liquids removed from the facility, as are the tank overheads in the shared manifold system and/or closed vent system ("CVS"), and not on an individual tank basis.

Thief hatch and PRV requirements associated with storage vessels that are not affected facilities, or part of a CVS, should be exempt from LDAR requirements (including recordkeeping and reporting), but due to their inclusion in the "fugitive emission components" definition [102] and the language in § 60.5397a(d)(1)(iv) [103] it seems unclear. Those emissions would have been accounted for in the PTE calculations and are not fugitive emissions.

F. Leak Detection and Repair

The Independent Producers overarching concern is that much more information is required to be documented than is necessary. Many items on the extensive list provide no environmental benefit, or assurance of compliance. Many operators consider Colorado Reg 7 to be overly burdensome, yet it is still more streamlined and efficient than what is currently required in this rule. The following list is inclusive of the recordkeeping and reporting requirements that should be stricken:

- How the leak was repaired
- Time of the survey
- Name/ID of person performing the survey
- Weather and atmospheric conditions
- Deviations from the monitoring plan, or observation path (if they do not create a situation where the survey results are been negatively affected by the modification)
- Type of instrument used to resurvey following a repair is unnecessary

When one asks "what useful information does this provide regulators in regards to compliance assurance?", it is difficult if not impossible to produce an answer that justifies their inclusion, especially considering the associated resource and economic burden. It is the Independent Producers' contention that Colorado Reg. 7 should be the template for fugitive recordkeeping and reporting and request EPA modify these requirements accordingly.

G. Digital Photograph Requirement

Mandating digital photographs, or video records be kept and maintained when using OGI technology does not serve a useful purpose, or in any way ensure compliance with the rule. The EPA has never made the determination that a digital photograph of the analyzer readout is necessary to ensure compliance when using a traditional Method 21 protocol to satisfy LDAR

[102] 40 C.F.R. §60.5430a ("Fugitive Emission Component" definition)

[103] For ***all other*** fugitive emission components ***not associated with a closed vent system or a controlled storage vessel*** under this section, a narrative description of how the fugitive emissions components will be monitored.

requirements, and it subsequently should not be required when using OGI. This is a perfect example of an instance where streamlining could be successfully utilized to remove unnecessary requirements that impart undue burden and financial stress without environmental benefit or additional compliance assurance beyond maintaining records and submitting certified reports that are already required.

H. Observation Path Requirement

The proposed observation path deviation reporting requirements should be eliminated. The EPA has failed to provide adequate proof that this is necessary for compliance assurance, or address industry concerns related to the overly burdensome nature of the tracking, maintenance, and modification of the monitoring plan and/or observation path documents that would be needed to avoid deviation reporting. The CAA authorizes the EPA to promulgate performance standards, but it does not authorize the EPA to force owner/operators to use a single method of complying with those standards. In fact, the CAA mandates that the EPA allow owner/operators the flexibility to determine the most effective compliance method for specific requirements. Adherence to a prescriptive observation path, where even a slight departure creates a potential compliance issue through "deviation" reporting requirements, is unnecessary and in no way correlates to a more effective performance of the survey, or in any way contributes to a reduction of emissions. Facilities are frequently modified and changed through equipment and component additions/removals which creates a perpetual evolution regarding the most effective camera position for successful OGI surveys. Even in situations where the facility equipment has not changed, weather conditions and other environmental factors create scenarios where the survey approach needs to be adjusted in order to achieve the desired result. These on-the-fly adjustments to the monitoring plan and/or observation path should not be considered a reportable deviation. Furthermore, they are absolutely critical to the successful outcome of the survey and applying any sort of negative association by reporting them as "deviations" is counterproductive to the overall intent of the rule. The Independent Producers understand that the EPA has stated that deviations from the monitoring plan are not necessarily deviations from the rule requirements,[104] but we have a difficult time reconciling that when considering the definition of deviation[105] and the very real possibility that regulators will view these reported "deviations" as a failure to meet the requirements of the regulation as the definition suggests. Deviation reporting would also make any Title V facilities subject to OOOOa requirements vulnerable to additional reporting, and possibly enforcement action due to the deviation reporting requirements for major sources.

The EPA has failed to provide a satisfactory explanation for the inclusion of the very tedious and costly recordkeeping and reporting requirements regarding monitoring plans and observation paths, especially considering there are much simpler and more reasonable methods for achieving compliance assurance. The Independent Producers urge the EPA to remove the recordkeeping and reporting requirements regarding deviations and replace them with more flexible performance based standards. These could include requirements for images to be obtained with an unobstructed view (when possible), a requirement that all affected facilities and

[104] 83 Fed. Reg. at 52078

[105] 40 C.F.R. § 60.5430a ("Deviation" definition)

components must be surveyed, a requirement for the operator to position the camera in such a manner that the most accurate image is captured, etc. In the event EPA chooses to maintain the deviation reporting requirements for monitoring plans and observation paths it is imperative that the definition of deviation be modified such that minor changes that are necessary to effectively and satisfactorily to complete the survey are not included.

1. Compliance and Emissions Data Reporting Interface ("CEDRI")

The Independent Producers understand that the CEDRI system is being reconsidered, but we still maintain that after it has been activated that an extended transition period must be utilized to eliminate delays and compliance issues related to system bugs and other integration problems. In addition, it has come to our attention that the few operators that have attempted to use the electronic reporting system have discovered that the process of obtaining facility ID's by first loading all facilities into CEDRI is extremely burdensome with respect to time and resources. This extra step is necessary before data can even begin to be entered into the system. The process of obtaining facility ID's must be simplified before the CEDRI system can be considered an acceptable method of data reporting.

VII. DEFINITION OF MODIFICATION

A. The EPA's Assumptions Associated with Refracturing a Well Does Not Justify Abandoning a Demonstrated Emissions Increase.

The definition of "Modification of a Well Site" proposed by the EPA in the NSPS for the Oil and Natural Gas Sector, 40 CFR 60.5365 a(i)(3), is inconsistent with the definition of "modification" under Section 111 of the CAA both in concept and fact. In the context of the EPA's immediate need to consider staying the fugitive emissions requirements, the impact of the Subpart OOOOa NSPS on modifications is significant. The CAA defines "modification" in the context of Section 111 as:

> … any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.[106]

This is not the criteria that the EPA used in defining "modification" in Subpart OOOOa. In Subpart OOOOa, the EPA states:

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

[106] 42 U.S.C.A. § 7411(a)(4).

(iii) A well at an existing well site is hydraulically refractured.[107]

The EPA justifies its use of this definition in the Federal Register Notice on Subpart OOOOa by stating:

> The EPA believes the addition of a new well or the hydraulically fracturing or refracturing of an existing well will increase emissions from the well site for the following reasons. These events are followed by production from these wells which generate additional emissions at the well sites. Some of these additional emissions will pass through leaking fugitive emission components at the well sites (in addition to the emissions already leaking from those components). Further, it is not uncommon that an increase in production would require additional equipment and, therefore, additional fugitive emission components at the well sites. We also believe that defining "modification" to include these two events, rather than requiring complex case-by-case analysis to determine whether there is emission increase in each event, will ease implementation burden of owners and operators. For the reasons stated above, EPA is finalizing the definition of "modification" of a well site, as proposed.[108]

This rationale is generally incorrect as a matter of concept because emissions do not arise from the fracturing of a well, but from production and the equipment to manage these emissions which are in place at the time of the fracturing. In addition, it is factually incorrect to automatically associate an increase in fugitive emissions and, as a result, a "modification" with each instance when a well is refractured. Production from any oil and natural gas well will always decline over time. The graph on page 9 of these Comments shows a typical decline curve for hydraulically fractured wells. Refracturing a well is a normal operational practice to recover some portion of declining production from existing wells. A refractured well will seldom, if ever, bring its production back to its initial volume or operating pressure. If an operator is committed to the expense associated with refracturing a well, part of standard operating practices are to evaluate the equipment on site to ensure that as much gas is recovered as possible. Again – what the EPA views as a pollutant, the industry views as its product. The equipment designed and installed at a particular well is designed to capture the maximum amount of methane or "emissions" that well is anticipated to produce when initially fractured. That same equipment is most likely "oversized" for a refracturing of the well.

The occurrence of a modification under the overarching definition contained in Section 111 requires a calculated increase in the baseline level of actual emissions.[109] Although the CAA defines a "modification" as any physical or operational change causing increased emissions, it does not specify how to calculate "increases" in emissions.[110] If the legislative intent of a statutory provision is ambiguous, then a court is entitled to consider "whether the agency's

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[107] 81 Fed. Reg. 35900 (June 3, 2016).

[108] 81 Fed Reg. 35881 (June 3, 2016).

[109] *New York v. U.S. Environmental Protection Agency*, 413 F.3d. 3, 19 (D.C. Cir., 2005).

[110] 42 U.S.C.A. §7411(a)(4).

[interpretation]is based on a permissible construction of the statute.[111] In the event the Agency's application meets that standard, a court will give that interpretation "controlling weight unless [it is] arbitrary, capricious or manifestly contrary to the statute.[112] The NSPS does not provide any methodology to support its definition of "modification", it simply assumes that any hydraulic refracture results in increased emissions. Refracturing a low production well is simply does not restore an underperforming well to levels that exceed or even come close to its original production level.

B. The EPA Acknowledged its Logical Inconsistency but has Failed to Justify Such Inconsistency.

In the Reconsideration Rulemaking, the EPA quoted comments previously made by the Independent Producers, not once but twice:

> 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 contexts to eliminate an 'emissions increase' requirement in the traditional definition of 'modification.;[113]

The EPA continues to argue that additional equipment will be installed when a well is refractured despite industry's statements to the contrary. In some instances additional equipment may be added but for the most part, equipment is not added. The equipment is designed to the capture the pressures and volumes expected from the initial fracture. The EPA's rational also assumes leaks at the existing equipment. The EPA also discusses other hypothetical instances where a refracture *could* result in an emissions increase.[114] The EPA's rational relies on the words "could", "may" and "possibly." This should not be the basis for regulating thousands of existing sources. If the EPA is intent on assuming emissions increases with refracturing a well, which seems heavily reliant on the assumption of leaking components, The EPA should allow operators to conduct a pre-refracture LDAR survey option, which, if demonstrates no leaks, would allow for refracturing that does not trigger a modification.

The EPA also attempts to explain away the inconstancy by citing "support for the petitioners' assertion that equipment counts can vary based on the amount of production at a well site."[115] The Independent Producers do not dispute that the number of equipment counts can and does vary based on the amount of production at a well site. That fact does not justify EPA

[111] *Chevron U.S.A., Inc. v. Natural Res. Def. Council*, 467 U.S. 837, 843 (1984).

[112] *Chevron* at 844.

[113] 83 Fed. Reg. 52,067; 83 Fed. Reg. 52,073 (2018).

[114] 83 Fed. Reg. 52,073 (2018).

[115] 83 Fed. Reg. 52,067 (2018).

ignoring or substantially discounting the impact of decreased production/pressure/volume at low production wells and the impact on emissions. While the Independent Producers appreciate the EPA's efforts to create a Model Low Production Well, as discussed earlier, the assumed equipment counts are high and overestimate emissions from low production wells.

VIII. CONCLUSIONS

The Reconsideration Rulemaking creates opportunities to address issues that were not fully understood or considered in the rush to complete Subpart OOOOa under the political pressures of the previous Administration. The Independent Producers support this essential action. In particular, the Independent Producers support the following positive changes:

> Changing the large production well fugitive emissions program to an annual cycle. The EPA's initial actions in Subpart OOOOa were based on inaccurate assumptions. As the API has identified, both the initial failure rate and the time for subsequent actions were incorrect and drove the EPA to overvalue a semi-annual cycle. The revisions to an annual cycle is an appropriate step.
>
> Addressing the requirements to use a Professional Engineer to certify certain actions and the revisions to the provisions on pneumatic pumps are important steps forward but both need additional clarification and modifications.

However, as stated above, the Independent Producers believe that additional changes are essential to fully address the regulatory framework in Subparts OOOO and OOOOa as they affect America's oil and natural gas productions. These include:

> The resurrection of a distinction for low production wells is a key and essential part of the new proposal. However, as the Independent Producers discuss above, the proposal falls short of being a workable structure. No specific requirements for low production wells should be required unless and until the EPA obtains specific information on low production well emissions and determines regulations are necessary and that cost-effective regulations can be created.
>
> The EPA's proposal on storage vessels needs to be significantly revised or eliminated. The Agency's proposal to prohibit averaging of throughput across tank batteries inappropriately ignores the relevant process unit and is inconsistent with recent consent decrees related to the design and operation of vapor control systems on storage tanks/vessels. The EPA's concern about the amount of storage vessels subject to Subpart OOOOa is overstated and unfounded. Its proposal to calculate individual tank emissions based upon throughput to each individual tank is technically flawed and overly burdensome. The EPA's proposed revisions to what constitutes "legally and practically enforceable limits" is unnecessary and arbitrarily interferes with the Clean Air Act's cooperative federalism where the states are to take lead on implementation.
>
> The Independent Producers support the AMEL options in the proposal to use modeling to test technologies in a controlled test environment, and to allow manufactures/vendors to apply for approvals. However, the EPA should allow for basin-wide approvals of emerging technology for use in complying with the LDAR requirements in the rule.

The EPA should recognize the approved state LDAR programs as wholly ambivalent to Subpart 0000's LDAR program and fully delegate the implementation of the LDAR monitoring provisions to these respective states. Alternatively, the EPA could require the fugitive emissions component definition from Subpart 0000a to be used when following an alternative approved state program, but the EPA should not require a duplicative administrative burden; to do so would be an undue burden with no corresponding environmental benefit.

The Independent Producers believe that further changes to limit excessive recordkeeping and reporting need to be made – changes to prevent unnecessary burdens that have no environmental benefit – and the definition of "modification" should be refined to be consistent with the intent of the CAA.

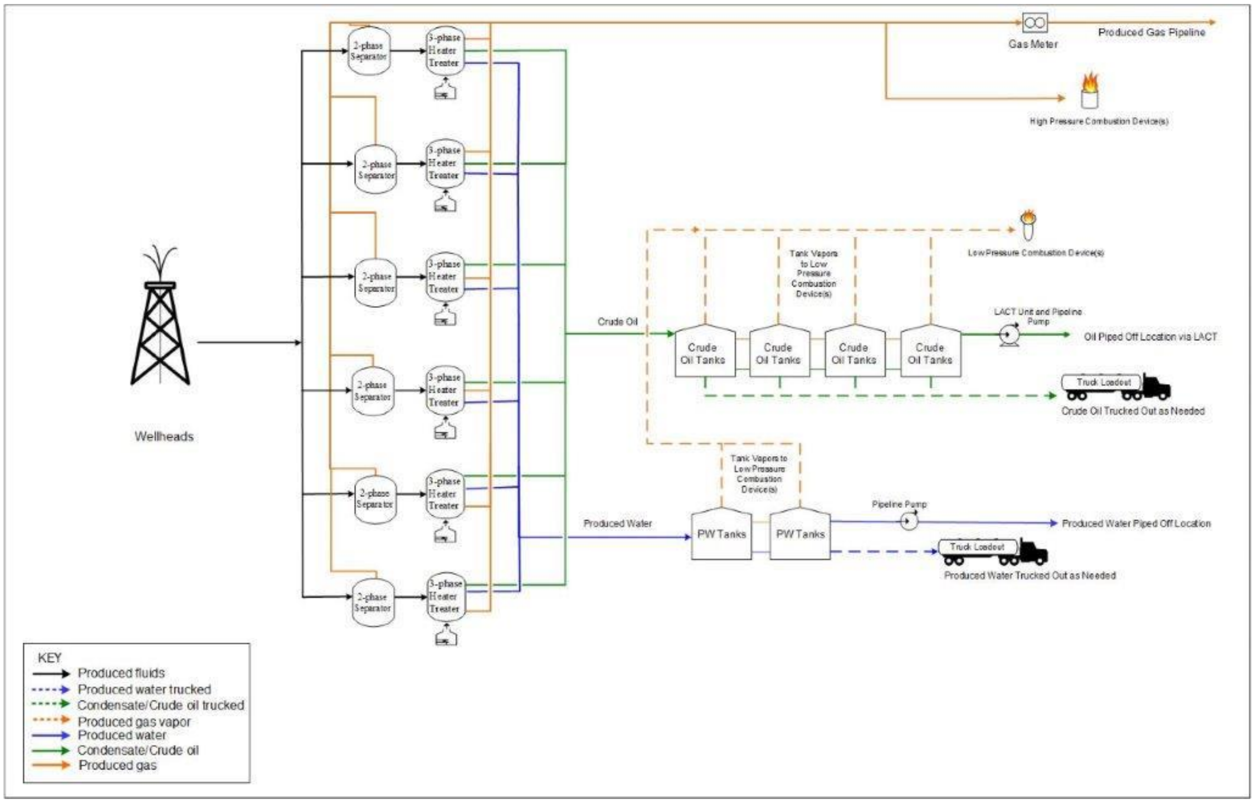
The Independent Producers submit these Comments collectively. The Independent Producers also endorse those Comments that are submitted separately by member organizations. Additionally, the Independent Producers support the Comments and proposals submitted by the API and commend its information supporting an annual fugitive emissions program for large production wells to the EPA.

If there are questions regarding these Comments, please contact me, counsel for the Independent Producers.

Respectfully submitted,

James D. Elliott
Counsel for Independent Producers

APPENDIX A



Gas Meter
Produced Gas Pipeline
High Pressure Combustion Device(s)
2-phase Separator
3-phase Heater Treater
Low Pressure Combustion Device(s)
Tank Vapors to Low Pressure Combustion Device(s)
Crude Oil
Crude Oil Tanks
LACT Unit and Pipeline Pump
Oil Piped Off Location via LACT
Truck Loadout
Crude Oil Trucked Out as Needed
Wellheads
Tank Vapors to Low Pressure Combustion Device(s)
Pipeline Pump
Produced Water
PW Tanks
Produced Water Piped Off Location
Truck Loadout
Produced Water Trucked Out as Needed
KEY
Produced fluids
Produced water trucked
Condensate/Crude oil trucked
Produced gas vapor
Produced water
Condensate/Crude oil
Produced gas