**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**

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| **White Papers on** | ) | |
| **Methane and VOC Emissions** | ) | *Via email to oilandgas.whitepapers@epa.gov* |
| **in the Oil and Natural Gas Sector** | ) | *June 16, 2014* |
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Submitted on behalf of the Sierra Club, Natural Resources Defense Council, Clean Air Task Force, and Earthworks.

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| **White Papers on Methane and VOC Emissions in the Oil and Natural Gas Sector** | ) ) ) ) ) ) | *Via email to oilandgas.whitepapers@epa.gov* *June 16, 2014* |

Thank you for accepting these comments on EPA's white papers regarding methane and VOC emissions in the oil and natural gas sector, released April 15, 2014. We submit these comments on behalf of the Sierra Club, Natural Resources Defense Council, Clean Air Task Force, and Earthworks ("Commenters").

## I. Introduction

EPA's five white papers demonstrate that the oil and gas sector emits enormous amounts of harmful methane and that timely action by EPA could significantly curtail these emissions. Most importantly, the white papers support action by EPA directly regulating methane from this source category under Section 111 of the Clean Air Act, including both existing and new or modified sources. Only through such an approach can EPA maximize the available reductions in methane emissions from this sector and meet the Obama Administration's climate goals.

Avoiding many of the impacts brought on by climate change will require dramatic reductions in greenhouse gas emissions, including methane. The Intergovernmental Panel on Climate Change ("IPCC") recently affirmed that to avoid catastrophic warming of 2° C or greater, the U.S. mustreduce total greenhouse gas emissions, relative to 2005, by at least 17% by 2020, 42% by 2030, and 83% by 2050—targets President Obama announced in Copenhagen in 2009 and committed to in Cancun in 2010.[1] The most optimistic projections from EPA and the Energy Information Administration ("EIA") of the current trajectory of U.S. greenhouse gas emissions in 2020 exceed the Administration's target level by over 800 MMT $CO_2e$[2]. Garnering all achievable

[1] *See, e.g.*, IPCC, *Fifth Assessment Report, Working Group 3: Summary for Policymakers* (2014) at 13 *available at* http://report.mitigation2014.org/spm/ipcc_wg3_ar5_summary-for-policymakers_approved.pdf; *see also* United States Department of State, Letter to Executive Secretary of United Nations Framework Convention on Climate Change Confirming US Copenhagen Targets, (Jan. 28, 2010), *available at* https://unfccc.int/files/meetings/cop_15/copenhagen_accord/application/pdf/unitedstatescphaccord_app.1.pdf, and United States Framework Convention on Climate Change, Compilation of economy-wide emission reduction targets to be implemented by Parties included in Annex I to the Convention (June 7, 2011), *available at* http://unfccc.int/resource/docs/2011/sb/eng/inf01r01.pdf.

[2] This estimate was calculated from table 5-1 in the *United States Climate Action Report*, available at http://www.state.gov/e/oes/rls/rpts/car6/ and adjusted with global warming potentials from IPCC's Fourth Assessment Report, in accordance with the "Key Parameters of the U.S. Economy-wide Emission Reduction Targets" spelled out in Table 1 of the *First Biennial Report of the United States of America, available at* http://www.state.gov/documents/organization/219039.pdf.

methane reductions from the oil and gas sector is therefore critical to reaching the initial 17% reduction target, and a necessary complement to the recent carbon dioxide standards for power plants towards this end. Furthermore, it is clear from existing pollution levels that voluntary measures will be insufficient.

Methane, an extremely potent climate change pollutant, is the second most emitted greenhouse gas in the EPA's 2014 Greenhouse Gas Inventory.This source, estimates that in 2012, the U.S. emitted 29.8 million tons of methane,[3] which EPA concludes represents 9% of total US greenhouse gas emissions in terms of carbon-dioxide equivalent ($CO_2e$).[4] The oil and gas industry, in turn, is among the nation's top three industrial contributors to human-made climate pollution. According to the 2014 Inventory, this sector produces approximately 161.6 MMT of $CO_2$-equivalent in methane each year through venting and leaking,[5] making it the largest source of anthropogenic methane pollution in the U.S.

Importantly, the actual impact of this pollution is much higher than indicated in the Inventory, which understates both the potency of methane and the amount of methane emitted by the oil and gas sector, as we explain below. Even accepting the Inventory's figures, however, it is clear that direct regulation of methane is critical. Such action will have co-benefits outside of those related to climate change, as methane also causes harms distinct from those directly related to climate change—for example, methane increases smog-forming ozone, which negatively impacts human respiratory and cardiovascular health and damages crops and vegetation. Additionally, methane is emitted along with other smog- and particulate-forming co-pollutants as well as hazardous substances. Measures to reduce methane emissions from oil and gas systems will also help curb emissions of these co-pollutants.

The last seven years have shown that the Clean Air Act is an appropriate and necessary means of reducing the threat of climate change by cutting greenhouse gas emissions. After the Supreme Court recognized in *Massachusetts v. EPA,* 549 U.S. 497, 528-29 (2007) that greenhouse gases are air pollutants covered under the Clean Air Act, EPA responded by determining that greenhouse gases, including methane, endanger public health and welfare. *See* 74 Fed. Reg. 66,496 (Dec. 15, 2009). The Supreme Court further confirmed that section 111 of the Clean Air Act is an appropriate pathway to reduce greenhouse gas emissions from stationary sources. *Am. Elec. Power Co. ("AEP") v. Connecticut,* 131 S.Ct. 2527, 2537-39 (2011). Noting that this section of the statute directs EPA to list particular "categories of sources" that, in the Agency's judgment, "caus[e], or contribut[e] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare…", the Court acknowledged in *AEP* that section 111 requires "standards of performance" for pollutants emanating from sources in a listed

[3] EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012* (Apr. 2014) ("2014 Inventory"), Table ES-2 (estimating 567.3 Tg $CO_2e$ from $CH_4$), *available at* http://epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2014-Chapter-Executive-Summary.pdf. This table uses a 100-year methane GWP of 21, indicating 27 Tg (or million metric tons) of methane. In this comment, we express units in short tons unless otherwise specified. 27 million metric tons is equivalent to 29.8 million short tons.

[4] *Id.* at Table 2-1, *available at* http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2014-Chapter-2-Trends.pdf.

[5] *Id.*

category. *Id.* This duty entails performance standards for both new sources under 111(b) and existing sources under 111(d). S*ee* 42 U.S.C. § 7411(b) and (d).[6]

Although the Court in *AEP v. Connecticut* focused specifically on section 111 regarding $CO_2$ emissions from power plants, the logic of that holding extends to all industrial sources of GHG pollution, and the oil and gas sector is, like power plants, a listed source category that is already regulated under section 111. EPA acknowledged in the 2012 rulemaking that the oil and gas sector emits significant levels of methane; as we discuss in these comments, reasonable cost controls are available to curb those emissions. For these reasons, EPA must set methane standards and guidelines for the oil and gas sector under Sections 111(b) and (d) of the Clean Air Act.

Indeed, the urgent need for methane regulations was evident in information presented to the agency in 2011 and 2012, during its mandatory review of section 111 performance standards for the oil and gas industry that resulted in the 2012 NSPS for VOC emissions. The five white papers that EPA released in April of this year and the studies summarized therein overwhelmingly affirm this conclusion. Specifically, these papers demonstrate that:

- Numerous sources of methane emissions in the oil and gas sector, including those for which the 2012 NSPS does not prescribe performance standards, are significant sources of methane emissions;

- Available control technologies can substantially reduce these methane emissions; and

- Costs for these control technologies are reasonable.

Accordingly, EPA can and must take action now to control methane emissions from oil and gas industry sources directly. As the IPCC has repeatedly admonished, acting now will be more effective and cheaper than acting later.[7]

Uncertainty regarding the exact amount of methane emissions from the oil and gas sector in no way justifies EPA's delay in regulating these emissions. As we discuss below, the studies cited in the white papers may differ in their exact estimates of emissions from particular components, and studies using atmospheric measurements of methane (which were generally not discussed in the white papers) provide significantly higher estimates of total methane emissions from natural gas systems. Nevertheless, while there may be uncertainty as to precisely how much methane the sector emits, there is no uncertainty on the issues EPA must resolve in setting section 111 standards: whether the amount of methane is significant enough to warrant regulation under section 111 and whether there are available technologies to reduce these emissions at reasonable costs.

For the reasons stated below, EPA must act, and act *now*, to propose section 111(b) and (d) standards and guidelines for methane emissions from (at a minimum) each of the sources discussed in the white papers.

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[6] Under section 111(b), EPA issues direct regulations of the new sources in the regulated category. Under 111(d), the agency provides mandatory emission guidelines that states then use to develop regulations for existing sources.
[7] *See, e.g.*, IPCC, *supra* n. 1, at 13-14.

## II. Scientific and Legal Background

### A. Methane Is A Harmful Air Pollutant

Methane is a highly potent greenhouse gas: in its most recent climate assessment, the IPCC estimates that fossil methane has a 100-year global warming potential (GWP) of 36, meaning that one ton of methane warms the Earth's climate as much as 36 tons of carbon dioxide over a 100-year time period. For a twenty year time frame, the GWP of fossil methane is 87.[8] This estimate represents the current consensus of the scientific community based on the latest research. In contrast, EPA's inventories still use a 100-year GWP for methane, including fossil methane, of 21. This value has been out of date since 2001[9] and does not reflect the research that has been conducted in the intervening time. In addition, methane is an ozone precursor;[10] as such, it contributes to the formation of smog, which causes significant human health impacts (including asthma attacks, respiratory disease, heart attacks, and premature death) and can destroy crops and vegetation.

Although a comprehensive estimate of the social cost of methane has not yet been developed, a peer-reviewed analysis by EPA economists recently estimated the figure at $880 per short ton for the year 2015, assuming an annual discount rate of 3%.[11] This figure was derived using the same methodology as used for the estimates of the social cost of carbon ("SCC"), building on work developed over several years and recently updated by the Interagency Working Group on the Social Cost of Carbon. While this research presents an important starting point, subsequent research indicates that it is too low. In particular, since this paper's publication, estimates of two inputs to this study—methane's global warming potential and the social cost of carbon—have been revised dramatically upward. This study used IPCC's fourth assessment report's estimates of methane's global warming potential, but as noted above, the IPCC's fifth assessment report increased the estimate of methane's 100-year global warming potential by 44%.[12] Similarly, in 2013 the federal Interagency Working Group increased its estimates of the social cost of carbon, using the same 3% annual discount rate, by 50%.[13] While the 2013 Interagency Working Group estimates of the SCC represent the most comprehensive analysis of this issue conducted thus far, Sierra Club, NRDC, and other environmental organizations have commented elsewhere that even

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[8] IPCC, *Climate Change 2013: The Physical Science Basis* (Sept. 2013), Chapter 8, page 714, Table 8.7, *available at* https://www.ipcc.ch/report/ar5/wg1/.

[9] IPCC's Third Assessment report updated the 100-yr GWP for methane (to 23) in 2001, and it was subsequently updated, increasing each time, in 2007 and 2014.

[10] *See* 76 Fed. Reg. 52,738, 52,791 (Aug. 23, 2011).

[11] *See* Marten, A.L., and Newbold, S.C., *Estimating the social cost of non-$CO_2$ GHG emissions: Methane and nitrous oxide*, 51 Energy Policy 957 (2012), attached as **Ex. 1.**

[12] *Compare id.* at 13 (citing Interagency Working Group on Social cost of Carbon, *Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* (Feb. 2010)), *available at* http://www.whitehouse.gov/sites/default/files/omb/inforeg/for-agencies/Social-Cost-of-Carbon-for-RIA.pdf) *with* Interagency Working Group on Social Cost of Carbon, United States Government, *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* (Nov. 2013) at 3, *available at* http://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf. The 2013 estimates are 50% higher for emissions in 2010, with greater percentage increases in subsequent years.

[13] *Id.* at 16 (referencing IPCC AR4 GWPs).

these SCC figures significantly underestimate the true social cost of carbon, possibly by several orders of magnitude.[14] For these reasons, the true social cost of methane likely exceeds the cited figure of $880 per short ton.

### B. Atmospheric Measurements Indicate That the White Papers Drastically Understate Oil and Gas Methane Emissions

The studies reviewed in the white papers generally estimate aggregate emissions using "bottom-up" methods. These methods use an estimate of the average emissions from an individual piece of equipment or individual event, such as a high-bleed pneumatic device or a well completion, and multiply that per-component value by an estimate of the total number of components or events of that type. A different method of estimating oil and gas sector methane emissions is a "top down" approach, where researchers measure the methane accumulation in the atmosphere in areas where oil and gas activity is occurring and then estimate the fraction of this methane attributable to emissions from oil and gas activity. For example, a researcher might measure methane concentrations upwind and downwind of gas activity and then subtract out the methane estimated to have been emitted from other sources. Certainty in source attribution has increased in recent years as scientists are better able to distinguish methane sources based on detected levels of co-occurring compounds such as ethane or isotopic composition of atmospheric methane.

In the last two years, peer-reviewed publications utilizing top-down techniques to estimate methane emissions from oil and gas, have proliferated, and these studies provide compelling evidence that the aggregate methane emission estimates based on "bottom up" studies (such as those discussed in the white papers) underestimate oil and gas sector methane emissions by a significant margin. Two recent studies addressed natural gas's lifecycle methane emissions nationwide. The first, published by Scot M. Miller, *et al.*, reviewed atmospheric measurements of methane and concluded that "[t]he US EPA recently [in the 2013 Greenhouse Gas Inventory] decreased its [methane] emission factors for fossil fuel extraction and processing by 25–30% (for 1990–2011), but we find that [methane] data from across North America instead indicate the need for a larger adjustment of the opposite sign."[15] Specifically, Miller, *et al.* conclude that atmospheric measurements show that methane emissions from all sources were 50% higher than the 2013 Inventory's bottom-up estimate of emissions. They show that oil and gas emissions are a significant portion of the observed emissions not accounted for in EPA's Inventory, and suggest that the actual leak rate is likely to be 3% or more.[16] The second, published by Adam Brandt, *et*

[14] *See* Sierra Club, *Comments on the Interagency Working Group's (IWG) Technical Support Document: Social Cost of Carbon (SCC) for Regulatory Impact Analysis Under Executive Order 12866* (Docket Not. OMB-2013-0007-0083) (Feb. 25, 2014), *available at* http://www.regulations.gov/#!documentDetail;D=OMB-2013-0007-0083; EDF, NRDC, *et al.*, *Comments on the Interagency Working Group's (IWG) Technical Support Document: Social Cost of Carbon (SCC) for Regulatory Impact Analysis Under Executive Order 12866* (Docket No. OMB-2013-0007-0140) (Feb. 26, 2014), *available at* http://www.regulations.gov/#!documentDetail;D=OMB-2013-0007-0140**.**

[15] *See, e.g.*, Miller, S., *et al.*, *Anthropogenic emissions of methane in the United States,* Proceedings of the National Academy of Sciences (Dec. 10, 2013) ("PNAS Study"), at 20,022, *available at* http://calgem.lbl.gov/Miller-2013-PNAS-US-CH4-Emissions-9J5D3GH72.pdf.

[16] Specifically, the paper states that in moving from the 2012 Inventory to the 2013 Inventory, EPA "decreased its CH4 emission factors for fossil fuel extraction and processing by 25–30% (for 1990–2011), but we find that CH4 data from across North America instead indicate the need

*al*., similarly concluded that EPA's Inventory and other bottom-up estimates significantly underestimate methane emissions from oil and gas production.[17]

These nationwide studies stand in agreement with atmospheric studies examining individual regions, which have found even higher methane emissions in the regions studied. Two studies of Colorado's Denver-Julesberg Basin have concluded that during gas production alone (not including emissions from downstream segments of the industry - transmission and distribution), the gas leak rate was about 4%.[18] The same team of researchers found even higher methane leak rates in Utah's Uinta Basin, estimating escaped methane at 9 ± 3% of total production.[19]

What these top-down studies uniformly indicate is that the estimates of oil and gas methane emissions surveyed in the white papers are too low. This means, in turn, that action to address methane emissions is even more vital, and that the potential for total abatement is even greater than what would be supported by the white papers' cited literature alone.

### C. If Oil and Gas Production Continues to Increase, the Need for Action to Address Methane Emissions Will Likewise Increase

Over the course of the last decade, the development of new techniques to extract oil and gas, including hydraulic fracturing and horizontal drilling, have opened unconventional sources of hydrocarbons to development, such as shale gas, tight gas, and coalbed methane. As a result, gas and oil production have increased significantly in recent years. Some analysts anticipate a continuation of this trend; for example, EIA's Annual Energy Outlook report for 2014 projects increases in production of both oil and natural gas in the coming decades.[20] Our energy needs should instead be met through increasing reliance on other options, including renewable energy (wind and solar), energy efficiency and others; however, any increase in oil and natural gas production that does occur will only strengthen the need for EPA to stringently control methane.

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for a larger adjustment of the opposite sign." *Id.* The 2012 Inventory implied a leak rate of approximately 2.4%; a 25% increase brings the leak rate to 3%.

[17] Brandt, A.R., *et al.*, *Methane Leaks from North American Natural Gas Systems*, Science, Vol. 343, no. 6172 at pp. 733-735 (Feb. 14, 2014), *available at* http://www.novim.org/images/pdf/ScienceMethane.02.14.14.pdf.

[18] The 4% estimate is provided by the more recent of these studies, Petron, *et al*., A *new look at methane and non-methane hydrocarbon emissions from oil and natural gas operations in the Colorado Denver-Julesburg Basin*, 119:9 J. Geophys. Res. Atmospheres (June 3, 2014). *abstract available at* http://onlinelibrary.wiley.com/doi/10.1002/2013JD021272/abstract. This is consistent with an earlier study, by the same lead author, which estimated using top-down techniques that 2.3 to 7.7% of production was vented in the studied and concluded more generally that "the methane source from natural gas systems in Colorado is most likely underestimated by at least a factor of two." Petron, *et al.*, *Hydrocarbon emissions characterization in the Colorado Front Range: A pilot study*, 117:D4 J. Geophys. Res. Atmospheres 4304 (Feb. 21, 2012), abstract available at http://onlinelibrary.wiley.com/doi/10.1029/2011JD016360/abstract.

[19] Karion, *et al.*, *Methane emissions estimate from airborne measurements over a western United States natural gas field*, 40:16 Geophysical Research Letters 4393 (Aug. 27, 2013), abstract available at http://onlinelibrary.wiley.com/doi/10.1002/grl.50811/abstract. *See also* J. Tollefson, *Methane leaks erode green credentials of natural gas*, Nature (Jan. 2, 2013), *available at* http://www.nature.com/news/methane-leaks-erode-green-credentials-of-natural-gas-1.12123.

[20] EIA, *Annual Energy Outlook* (May 2014), Table 14: Oil and Gas Supply, *available at* http://www.eia.gov/forecasts/aeo/excel/aeotab_14.xlsx.

## D. The Clean Air Act's Section 111 Performance Standards Program

As mentioned above, section 111 of the Clean Air Act requires EPA to set technology-based "standards of performance" for listed "categories of sources" of air pollution. 42 U.S.C. § 7411. Such standards of performance must

> reflect[] 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.

*Id.* § 7411(a)(1). Congress' intent behind section 111 performance standards was "to induce, to stimulate, and to augment the innovative character of industry in reaching for more effective, less costly systems to control air pollution." *Sierra Club v. Costle*, 657 F.2d 298, 347 n.174 (D.C. Cir. 1981 (quoting legislative history). Once the standards for a particular source category are established, EPA "shall, at least every 8 years, review and, if appropriate, revise such standards following the procedure required by [section 111(b)]." 42 U.S.C. § 7411(b)(1)(B). EPA has long interpreted this "appropriateness" determination to turn on only two factors: 1) the amount of emissions of a given pollutant from that sources category; and 2) the availability of demonstrated control measures. *See, e.g.*, 50 Fed. Reg. 36,959, 36,961 (Sept. 10, 1985) (making negative determination based on lack of demonstrated control technology); 75 Fed. Reg. 54,994–95 (Sept. 9, 2010) (making positive determination based on significant emissions and existence of demonstrated control technology). S*ee also Nat'l Lime Ass'n v. EPA*, 627 F.2d at 426 n. 27 (discussing these factors). As such, EPA must regularly (but no less often than every 8 years) review source categories to ensure that the existing performance standards reflect the current and most innovative state of that industry's technological capabilities to reduce emissions from all pollutants.

### *i. Summary of EPA's 2012 NSPS*

Despite this charge, EPA stopped short when it finalized revisions to the oil and gas sector's NSPS in 2012. 40 C.F.R. §§ 60.5360-60.5430; s*ee also* 77 Fed. Reg. 49,489 (August 16, 2012). Namely, EPA failed to issue standards that reflect the maximum degree of methane reduction that was achievable considering the sector as a whole, choosing instead to focus on VOC emissions and reductions and to consider methane only as a co-benefit of the VOC standards. The resulting regulations cover only a small portion of the methane emission sources that exist throughout the oil and gas sector. This approach resulted in two significant omissions.

First, EPA's 2012 NSPS omits sources in the transmission and storage segment, where VOC emissions are low relative to methane because impurities are removed during gas processing. For example, only new compressors located *between* the wellhead and the transmission and storage segment are covered by the rule. 40 C.F.R. §60.5365(b). Compressors located at a well site or anywhere in the transmission and storage segments, and all existing compressors regardless of location, are currently exempt from regulation under the 2012 NSPS. The final rule applies the same limitation on covered sources by location and segment for pneumatic controllers. *Id.* § 60.5365(d). Second, because EPA arguably is not required to set emission guidelines for VOCs under section 111(d), the 2012 NSPS omit all existing equipment, which accounts for the vast majority of the sector's methane pollution.

### *ii. Section 111 and Costs*

Section 111(a)(1) directs EPA to "take into account" the cost of achieving reductions and any nonair quality health and environmental impacts and energy requirements when establishing performance standards for a category of sources. 42 U.S.C. § 7411(a)(1). Over several decades, the D.C. Circuit has fleshed out the meaning of this directive and determined that control costs must simply be "reasonable"—that is, they must not be "exorbitant" or too expensive for the industry to absorb in order to survive. For instance, in *Essex Chem. Corp.*, 486 F.2d 427, 433 (D.C. Cir. 1973) (holding that section 111 standards must be "reasonably reliable, reasonably efficient, and . . . reasonably . . . expected to serve the interests of pollution control *without becoming exorbitantly costly in an economic or environmental way*." 486 F.2d at 433 (emphasis added). Similarly, in *Portland Cement Association v. Train*, 513 F.2d 506, 508 (D.C. Cir. 1975), the court upheld EPA's interpretation that section 111's cost inquiry functions as a safety valve to ensure that the costs an NSPS imposes are not "greater than the industry could bear and survive," but would instead allow industry to "adjust" in a "healthy economic fashion to the end sought by the Act as represented by the standards prescribed." *See also Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999) ("EPA's choice [of BSER] will be sustained unless the environmental or economic costs of using the technology are exorbitant.").

The measures we discuss below would not only easily meet section 111's cost criteria, but would actually generate net profits for operators in most instances. Indeed, some industry actors are taking this issue seriously and voluntarily adopting methane controls such as those discussed in these comments. However, a variety of market conditions disincentive or inhibit companies from maximizing the available opportunities to reduce methane. These conditions include diverse ownership of the different parts of the system, ownership transfer of the gas moving through the system, higher rates of return from other investments, lack of knowledge of best practices, lack of incentive by independent contractors, or a simple lack of interest. Collectively, these factors result in a market failure with respect to methane, and regulations must be established to prevent the resulting wasteful and harmful pollution. Ultimately, such actions will not only provide climate and other environmental and health benefits, but they will generate profits for the sector as a whole.

In the sections that follow, we provide comments on each of the white papers in turn. As our analysis makes clear, direct regulation of existing sources of methane in the oil and gas industry, as well as new sources not covered in the 2012 NSPS rule, are not only warranted, but are critical. Without these controls, a critical group of GHG emitters will remain unregulated and the threat of climate change will only increase.

## III. Comments on the Compressor White Paper

### A. Introduction

Compressors are mechanical devices used in the oil and gas industry to increase the pressure of natural gas for several purposes, including separating higher molecular weight constituent (natural gas liquids) from raw gas and transporting gas across long distances. There are two main kinds of compressors that are used in the industry: reciprocating compressors and centrifugal compressors. Both kinds of devices experience gas leaks associated with their moving parts—shaft seals or rod packing systems, as described below—and from static connections at other locations on the compressor. The former category we refer to as seal leaks, and we address those emissions in this section. The latter category is more accurately considered fugitive emissions, which we address in our comments on the white paper concerning leaks.

Reciprocating compressors function by positive displacement, using a driveshaft and piston that move back and forth linearly to reduce the volume of a quantity of gas and increase its pressure. To minimize gas leakage around the driveshaft, reciprocating compressors include rod packing systems, which consist of a series of flexible rings encased in metal cups to form a seal around the shaft. As rod packing systems age, component wear reduces the effectiveness of the seal and more gas leaks into the atmosphere.

Centrifugal compressors are less common in the industry than reciprocating compressors, but are associated with higher emissions of methane and other pollutants. These devices draw in low-pressure gas and increase its pressure by directing it through a rotating set of vanes or impellers. To reduce leaks, the rotating shaft of each centrifugal compressor is equipped with either wet seals or dry seals. Wet seals utilize circulating streams of oil to lubricate the seal rings that absorb high pressure gas, which is typically vented into the atmosphere through a seal-degassing process. Dry seals, by contrast, consist of aerodynamic grooves that create a thin layer of high-pressure gas that separates the rotating rings and creates a natural seal against gas leakage. Compressors with dry seals emit approximately 87% less methane from seal leaks than those with wet seals, and also save operators money due to lower operating and maintenance costs.

The 2012 NSPS included operational requirements for compressors of both types that are constructed or modified after August 23, 2011 and that are located between the wellpad and the point at which the natural gas enters the transmission and storage segment. For centrifugal compressors equipped with wet seals, the rule requires operators to achieve a 95% reduction in VOC emissions from seal leaks by installing a gas recovery system for the seal oil degassing process.[21] Centrifugal compressors with dry seals are not covered by the rule. For reciprocating compressors in those portions of the industry, the rule requires rod packing replacement either every 26,000 operating hours or every 36 months.

While the 2012 NSPS will achieve some co-benefits from reduced methane emissions, it did not directly target methane, nor did it cover any existing compressors (*i.e.*, those compressors constructed or modified before August 23, 2011) or new or modified compressors on wellpads or in the transmission and storage segment. As such, there remain substantial opportunities to reduce methane emissions from centrifugal and reciprocating compressors at a reasonable or even negative cost. In this analysis, we recommend a series of measures that would significantly reduce seal leaks from oil and gas sector compressors. First, EPA must regulate new compressors that were not covered under the final 2012 NSPS and require periodic rod packing replacements at new wellhead, transmission, and storage segment reciprocating compressors and either dry seal installation or gas capture systems at new centrifugal compressors in the transmission and storage

[21] In its proposed rule, the agency considered requiring dry seals at all new centrifugal compressors in the gas processing segment. However, the final rule permits operators to use wet seal compressors at processing facilities so long as it uses a gas recovery system and reduces methane emissions from seal leaks by 95%. *See* 79 Fed. Reg. 49,490, 49,523 (Aug. 16, 2012). The controls we advocate would require existing centrifugal compressors equipped with wet seals to be retrofitted with dry seals or systems that achieve equal or greater reductions by capturing the gas from seal oil degassing process and directing it into compressor suction (or similarly utilize the gas through another mechanism).

segment. Second, EPA must require operators to replace rod packing systems periodically (i.e., every 36 months or every 26,000 operating hours) at all existing reciprocal compressors in all four segments of the oil and gas sector, from wellheads to gas distribution systems. Finally, EPA must require all existing wet seal centrifugal compressors in the oil and gas sector to be retrofitted either with dry seals or gas capture systems that direct gas from seal oil degassing units and direct it to compressor suction or other beneficial use.

The comments below are structured primarily around the 2011 Inventory to discuss abatement opportunities in line with the information EPA had when it proposed and developed the 2012 NSPS. Because the data on compressor emissions has not qualitatively changed between 2012 and today, our analysis based on 2011 Inventory data remains pertinent with regard to abatement opportunities for compressors, particularly for existing sources built prior to August 23, 2011. In addition, we also evaluate abatement opportunities from compressor seals in light of data from the 2014 Inventory as a point of comparison. As our analysis shows, the net emission reductions that can be achieved from the control measures we advocate are similar regardless of whether one uses 2014 or 2011 Inventory data; in both cases, these reductions are substantial.

In the sections that follow, we provide an overview of EPA's anticipated emission reductions from the 2012 NSPS. We then discuss the abatement opportunities available at existing reciprocal and existing compressors based on data from EPA's 2011 Inventory. Next, we examine the emission reductions that could be achieved by regulating new compressors not covered under the 2012 NSPS, again using data available to EPA in 2012. We then consider these total emission reduction figures in light of EPA's most recent data from the 2014 Inventory. Finally, we respond to the charge questions included in EPA's compressor white paper.

### B. Anticipated Emission Reductions from EPA's 2012 NSPS

EPA's final 2012 NSPS set operational standards to reduce VOC at new compressor seal leaks by approximately 1,736 tpy.[22] The rule requires control of all new reciprocating compressors and centrifugal compressors with wet seals "located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment." 79 Fed. Reg. at 49,543 (40 C.F.R. § 60.5365(b)-(c)). Hence, the rule covers new reciprocating compressors in the gas production (gathering and boosting activities only; wellpad units are not covered) and processing segments and new centrifugal compressors in the processing segment (no new centrifugal compressors are anticipated for gathering and boosting). In addition to VOC abatement, methane (8,139 tpy) and hazardous air pollutants ("HAP") (65 tpy) emission reductions are expected as co-benefits to the rule, as shown in the summary table below.[23]

[22] EPA, *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Technical Support Document for Proposed Standards* (July 2011) (hereafter, "TSD") at 6-15 (Table 6-6) (showing data for reciprocating compressors); EPA, *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Supplemental Technical Support Document for the Final New Source Performance Standards* (April 2012) (hereafter, "Supplemental TSD") at 6-2 (Table 6-3) (showing data for centrifugal compressors).
[23] *Id.*

**Table 1*: Emissions Abatement Estimations from 2012 NSPS***

| Commpressor Emissions Abatement Estimations from 2012 NSPS | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Equipment Type** | **Emissions abated per compressor (tons/year) in 2012** | | | **Number of New Devices/Yr** | **Total emissions abated (tons/year) in 2012** | | |
| | **Methane** | **VOC** | **HAP** | | **Methane** | **VOC** | **HAP** |
| New Gas Production (Gathering & Boosting) Reciprocating Compressors | 6.84 | 1.90 | 0.07 | 210 | 1,437 | 400 | 15 |
| New Gas Processing Reciprocating Compressors | 18.60 | 5.18 | 0.20 | 209 | 3,892 | 1,082 | 41 |
| **Subtotal** | | | | **419** | **5,329** | **1,482** | **56** |
| New Gas Processing Centrifugal Compressors | 216.15 | 19.51 | 0.70 | 13 | 2,810 | 254 | 9 |
| **Subtotal** | | | | | **8,139** | **1,736** | **65** |

Specifically, the final 2012 NSPS requires affected reciprocating compressors to replace rod-packing systems either after every 26,000 operating hours or after every 36 months. 79 Fed. Reg. at 49,544 (40 C.F.R. § 60.5385(a)(1)-(2)). Affected centrifugal compressors with wet seals must reduce VOC emissions from seal venting by 95% by installing a gas recovery system for the seal oil degassing process. 79 Fed. Reg. at 49,544 (40 C.F.R. § 60.5380(a)(1)-(2)). Alternatively, operators may avoid regulation under the 2012 NSPS by using dry seal centrifugal compressors, which are not considered affected facilities under the final rule. 79 Fed. Reg. at 49,500.

Based on these requirements, EPA estimated that the final rule would reduce VOC emissions at 419 affected reciprocating compressors by 1,482 tpy, along with co-benefits of 5,329 tpy methane and 56 tpy HAP.[24] EPA estimated the control cost for these units at $273 to $877 per ton of VOC abated.[25] For an estimated 13 affected centrifugal compressors, the agency calculated emission reduction benefits at 254 tpy VOC with co-benefits of 2,810 tpy methane and 9 tpy HAP.[26] The control cost for these units was estimated at $160 per ton of VOC abated.[27]

In total, EPA projected that the final rule would reduce methane emissions from compressor seal leaks by approximately 8,139 tpy. This abatement figure is relatively small because, as discussed earlier, the rule only applies to new and modified compressors—that is, compressors that are constructed or modified after August 23, 2011. 77 Fed. Reg. at 49,493. The final rule also exempts new reciprocating compressors on wellpads and in the transmission and storage segments, as well as new centrifugal compressors in the transmission and storage segments. Below, we discuss the emission reductions that could be achieved by controlling seal leak emissions at these devices.

[24] S*ee* Table 2, *supra*. *See also* TSD at 6-15 (Table 6-6). Note that Table 6-6 erroneously lists 375 as the number of new reciprocating compressors annually in the processing segment. Elsewhere, the TSD makes clear that this figure is actually anticipated at 209 new units per year. *See, e.g.*, *id.* at 6-7 (Table 6-4), 6-28, 6-29 (Table 6-13).
[25] TSD at 6-17 (Table 6-7).
[26] Supplemental TSD at 6-3 (Table 6-2).
[27] *Id.* at 6-2–6-3 (($3,132/compressor/yr)/(19.58 tpy/compressor) = $160/ton.

### C. Control Measures for Compressors Not Covered Under the 2012 NSPS: Anticipated Emission Reductions Based On Data Available to EPA In 2012

By requiring retrofits of existing wet seal centrifugal compressors with dry seals or gas capture systems, as well as routine replacement of rod packing systems at existing reciprocating compressors, EPA can achieve significantly greater reductions in methane emissions at a reasonable cost. Utilizing data available to EPA at the time of the 2012 NSPS rulemaking, we calculate the emission reduction opportunities from these measures at 525,218 tpy of methane, along with emission reduction co-benefits of 72,384 tpy VOC and 2,661 tpy HAP, as show in Table 2 below.

**Table 2:** ***Abatement Opportunities from Existing Gas Sector Compressors Using Data Available to EPA During 2012 NSPS Rulemaking***

| Emission Abatement Potential - Existing Compressors | | | |
|---|---|---|---|
| Equipment Type | Emissions abated (tpy) | | |
| | Methane | VOC | HAP |
| Existing Reciprocating Compressors | 292,267 | 33,102 | 1,203 |
| Existing Centrifugal Compressors | 232,950 | 39,282 | 1,459 |
| **Subtotal** | **525,218** | **72,384** | **2,661** |

Additionally, the 2012 NSPS did not apply to new reciprocating compressors located at wellhead sites or in the transmissions and storage segments, nor to new centrifugal compressors in the transmission and storage segment.[28] We estimate that a rule requiring control of seal emissions at these new units would reduce methane emissions by 22,576 tpy. While this number is lower than the reduction opportunities from existing compressors, it is important to keep in mind that it is a per-year estimate that only accounts for reductions in the first year of abatement. After the second year, emissions reductions would double, as the new, cleaner compressors installed in the first year would continue to emit less methane from seal leaks, and new compressors installed in the second year would add to the potential emissions reduction. These emission reduction benefits would continue to compound each year as new equipment is installed, and the 22,576 tpy would compound to a substantial abatement total over time.

As we explain in further detail below, these measures can be achieved at new and existing compressors at a control cost ranging from $49–$1,053 per ton of methane depending on the segment and compressor, exclusive of profits from the sale of captured fuel and operating and maintenance cost savings. Once these additional revenues are taken into account, the control costs for the measures would range from -$703 (that is, a net profit of $703 per ton of methane abatement) to +$821 per ton. In the sections that follow, we describe the abatement opportunities for seal emissions from existing oil and gas sector compressors. Our analysis uses the emission abatement factors that appear in the rulemaking documents for the 2012 NSPS and incorporates the activity counts and aggregate methane emissions data from EPA's 2011 Inventory, which was available to EPA when it developed the 2012 NSPS and which the agency relied upon for most data points in that analysis.

[28] EPA estimated that no new centrifugal compressors were estimated at wellheads or for gathering and boosting activities in the coming year. *See* TSD at 6-7 (Table 6-4). Hence, we do not consider emission reduction estimates from those kinds of units.

We note here that our calculations likely under-represent the true level of methane emissions from compressor seal leaks. This is because the most commonly used emission factors—including those used by EPA in its GHG Inventories and in developing the 2012 NSPS, which we rely on in this report—almost certainly underestimate the amount of methane emitted at each compressor. For example, to estimate emissions from reciprocating compressors, EPA used the emission factors calculated in the 1996 EPA/GRI study.[29] Yet a 2011 report by the University of Texas ("UT") and URS Institute suggests that the true level of emissions from these devices may exceed the EPA/GRI study's estimates by several orders of magnitude.[30] The UT/URS study authors caution that their study used a smaller sample set than the EPA/GRI study, and that "there is not enough data to draw a definitive conclusion." Accordingly, we do not rely on the UT/URS values in our analysis. Nevertheless, they indicate that emissions from gas sector compressors may well be much higher than either the EPA Inventory or the 2012 NSPS rulemaking materials presumed. For this reason, we assert that our estimates included herein are quite conservative.

Additionally, for the 38,410 units listed as "small gathering compressors" in the production sector, the 2011 Inventory uses an extremely low emissions factor of around 2 tpy/compressor. This amounts to around 0.2 tpy/compressor attributable to seal leaks, assuming (as we do) that 9.8% of these units' emissions are caused by seals. This figure, derived from the measurement of emissions from a single wellpad compressor in the 1996 EPA/GRI study, is approximately 57 times less than the Inventory's emission factor for "large gathering compressors." Although it is nearly certain that the 0.2 tpy/compressor figure drastically under-represents the true value for these units, we have not altered that figure when calculating emissions from existing compressors in the production sector.[31] Even with this added layer of conservatism, our data shows significant emission reduction potential at reasonable cost from the measures we discuss, and EPA must act promptly to adopt these or equivalent measures.

### i. Methane Abatement Opportunities for Existing Reciprocating Compressors

EPA's 2011 Inventory estimated that 48,469[32] reciprocating compressors were operating in the U.S. oil and gas sector in 2009. Additional compressors were added between that year and August 23, 2011, the cut-off date for existing sources, so this number is a conservative estimate. The 2011 Inventory estimated sector-wide methane emissions from these devices totaling 1,601,862

[29] *See* EPA and GRI, Methane Emissions from the Natural Gas Industry, Volume 2: Technical Report (June 1996), available at http://www.epa.gov/gasstar/documents/emissions_report/2_technicalreport.pdf.

[30] *See* URS Corporation and University of Texas, *Natural Gas Industry Methane Emission Factor Improvement Study Final Report* (Dec. 2011), at 37-38, *available at* http://www.utexas.edu/research/ceer/GHG/files/FReports/XA_83376101_Final_Report.pdf.

[31] In calculating control costs for existing units and potential abatement from new wellhead compressors, however, we revised the emission control factor that EPA used for wellhead units, which also derived from the 1996 EPA/GRI study. We discuss this in more detail on pages 16-17 below.

[32] EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (1990-2009) (Apr. 15, 2011) (hereafter, "2011 Inventory"), Annex 3, Tables A-120 through A-122 (34,930 production segment compressors + 4,876 processing segment compressors + 8,663 transmission and storage segment compressors = 48,469 reciprocating compressors in the oil and gas sector).

tons[33] (75.56 Bcf)[34] for 2009. This total includes emissions not only from reciprocating seals, but from fugitives as well—that is, leaks occurring at other locations on the compressor apart from seals. These data are presented in Table 3 below.

**Table 3*: Activity Counts and Aggregate Emission Estimates at Oil and Gas Sector Reciprocating Compressors- All Emissions***

| Existing Compressor Emission Estimates - Not Regulated by 2012 NSPS | | | | |
|---|---|---|---|---|
| **Equipment Type** | **Number of Devices** | **Emissions (tons/year) in 2009** | | |
| | | **Methane** | **VOC** | **HAP** |
| Existing Production Reciprocating Compressors | 34,930 | 90,885 | 25,266 | 954 |
| Existing Gas Processing Reciprocating Compressors | 4,876 | 423,030 | 117,602 | 4,442 |
| Existing Transmission Reciprocating Compressors | 7,197 | 847,955 | 23,488 | 678 |
| Existing Storage Reciprocating Compressors | 1,466 | 239,993 | 6,648 | 192 |
| **Subtotal** | **48,469** | **1,601,862** | **173,004** | **6,266** |

VOC and HAP emission estimates were computed using conversion factors from EPA 2011 TSD, Page 6-2.

We observe here that existing data for methane emissions from reciprocating compressors in the production sector likely dramatically underestimate the true emissions from these sources. As Table 3 shows, the 2011 Inventory estimated that emissions from reciprocating compressors in this segment are only 2.6 tons/compressor/year, whereas emission rates for such compressors in the other segments range from approximately 86 to 163 tons/compressor/year. There is no explanation for this wide disparity, and we contend that the emission estimates for the production segment are extremely conservative as a result.

Using data from the 1996 EPA/GRI Study, we estimated the portion of total methane emissions attributable to seal leaks, then multiplied the total emissions from reciprocating compressors by this factor to produce an estimate of emissions from seal leaks alone.[35] We estimated reciprocating compressor emissions due to seal leaks alone to be approximately 10% in the production segment, 28% in the processing segment, 24% in the transmission segment, and 18% in the storage segment. In our analysis of EPA's white paper on leaks/fugitive emissions, we address the remainder of the methane emissions from compressors, which occur due to leaks from a device's static components. We estimated methane emissions attributable to reciprocating compressor seal leaks to be 368,887 tpy, as shown in Table 4 below.

[33] *See id.* (82.45 Gg production + 383.77 Gg processing + 769.26 Gg transmission + 217.72 Gg storage = 1453.2 Gg sector wide; 1453.2 Gg *1,000 MT/Gg * 1.1023 tons/MT = 1,601,862 tons of methane emissions per year from seal leaks at oil and gas sector reciprocating compressors).
[34] To convert methane weight to volume, we used a standard conversion factor of .0212 tons/Mcf, which EPA used in the 2011 Inventory. (Hence, 1,601,862 tons * 1 Mcf per .0208 tons * 1 Bcf per 1,000,000 Mcf = 75.56 Bcf).
[35] GRI/EPA, *Methane Emissions from the Natural Gas Industry* (June 1996), Volume 8: Equipment Leaks, Table 4-8 (Production), Table 4-14 (Processing), Table 4-17 (Transmission) and Table 4-24 (Storage), *available at* http://www.epa.gov/gasstar/documents/emissions_report/2_technicalreport.pdf.

**Table 4*: Activity Counts and Aggregate Emission Estimates at Oil and Gas Sector Reciprocating Compressors- Seal Leaks Only***

| Existing Compressor Emission Estimates - Not Regulated by 2012 NSPS (Seal Leaks Only) | | | | | |
|---|---|---|---|---|---|
| **Equipment Type** | **Number of Devices** | | **Emissions (tons/year) in 2009** | | |
| | | **Seal Leak % of Total** | **Methane** | **VOC** | **HAP** |
| Existing Production Reciprocating Compressors | 34,930 | 9.8% | 8,903 | 2,475 | 93 |
| Existing Gas Processing Reciprocating Compressors | 4,876 | 27.9% | 117,996 | 32,803 | 1,239 |
| Existing Transmission Reciprocating Compressors | 7,197 | 23.6% | 199,955 | 5,539 | 160 |
| Existing Storage Reciprocating Compressors | 1,466 | 17.5% | 42,033 | 1,164 | 34 |
| **Subtotal** | **48,469** | | **368,887** | **41,981** | **1,526** |

VOC and HAP emission estimates were computed using conversion factors from EPA 2011 TSD, Page 6-2.

As EPA recognized in the 2012 NSPS, methane emissions from reciprocating compressor seal leaks can be reduced substantially by replacement of worn-out rod packing systems on a periodic basis. The agency reports that newly installed packing typically leaks 11-12 scfh, whereas worn packing has been reported to leak up to 900 scfh.[36] In these cases, replacing packing before serious wear occurs can reduce emissions by 90-95%. However, depending on the degree of wear, and compressor maintenance history, emission reduction improvements would be less than 90-95% for the average compressor. Periodic replacements of rod packing materials is also good operating and maintenance protocol: operators that carefully monitor and replace compressor rod packing systems on a routine basis can conserve additional gas for sale that would otherwise have been leaked and reduce piston rod wear, both of which increase profit.

As part of the 2012 NSPS rulemaking, EPA estimated the total amount of methane leaked and the amount of abatement that could be achieved from reciprocating compressors in each segment based upon the rule's requirements that rod packing systems be replaced every 36 months or every 26,000 operating hours. The agency calculated abatement opportunities of 63.2%[37] for devices in the production segment, approximately 80% for those in the both the processing and transmission segments, and 77.3% in the storage segment.[38] These estimates were for new compressors; leak rates for existing compressors are likely higher. We applied the 2012 NSPS

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[36] EPA, *Lessons Learned from Natural Gas STAR Program, Reducing Methane Emissions From Compressor Rod Packing Systems* (Oct. 2006), at 1, *available at* http://www.epa.gov/gasstar/documents/ll_rodpack.pdf.

[37] This figure combines data in the TSD for both reciprocating compressor types listed for the production segment—wellhead units and gathering and boosting units. We took this approach because it is not clear in EPA's Inventory for either 2011 or 2014 which production sector compressors are wellhead units and which are gathering and boosting units. Hence, we derived an abatement percentage based on data for all production sector compressors—wellhead and gathering/boosting units alike—and applied that to the aggregated data for all production sector devices listed in the Inventory.

[38] TSD at 6-10 (Table 6-5), 6-15 (Table 6-6). The abatement percentages for each segment were calculated by dividing the abatement opportunity figures presented in Table 6-6 by the baseline aggregate emission figures presented in Table 6-5.

abatement potential factors to each segment to compute a total methane reduction of 292,267 tpy from seal leaks at existing reciprocating compressors, along with co-benefits of 33,102 tpy in VOC abatement and 1,203 tpy in HAP abatement.

**Table 5*: Total Abatement Opportunities from Seal Leaks at Existing Oil and Gas Sector Reciprocating Compressors***

| Emission Abatement Potential - Rod Packing Replacement at Existing Reciprocating Compressors | | | | |
|---|---|---|---|---|
| **Equipment Type** | **% Abatement** | **Emissions abated (tons/year)** | | |
| | | **Methane** | **VOC** | **HAP** |
| Existing Production Reciprocating Compressors | 63.2% | 5,625 | 1,564 | 59 |
| Existing Gas Processing Reciprocating Compressors | 79.9% | 94,281 | 26,210 | 990 |
| Existing Transmission Reciprocating Compressors | 80.0% | 159,888 | 4,429 | 128 |
| Existing Storage Reciprocating Compressors | 77.3% | 32,473 | 900 | 26 |
| **Subtotal** | | **292,267** | **33,102** | **1,203** |

We observe here that the GHG Inventory presents aggregated data for production segment reciprocating compressors without providing specific information for wellpad devices. Therefore, our estimates for existing units do not offer breakdown figures for wellpad devices and gathering and boosting devices, but instead present data for production segment compressors in the aggregate. However, in its TSD for the 2012 NSPS, EPA calculated separate cost estimates for emission controls at wellpad compressors and gathering and boosting compressors, even while it declined to regulate the latter devices in its final rule. The agency's cost estimate for controlling wellhead reciprocating compressors amounted to $15,802 per ton of methane. By contrast, the agency estimated control costs of $244, $76, $77, and $104 for reciprocating compressors at gathering and boosting, processing, transmission, and storage facilities, respectively (exclusive of savings from conserved gas).

EPA's estimated control cost of $15,802 per ton of methane at wellhead reciprocating compressors patently overestimates the true cost of controlling emissions at these units. It is based on an emission abatement factor (or emission control factor) of just 0.158 tons of methane per year for each wellhead reciprocating compressor.[39] This control factor of .158 tpy per device is substantially less than those factors used for any other reciprocating compressor in the oil and gas sector (which range from 6.84 to 21.70 tons of methane per year per compressor) and derives from measurements from a single four-cylinder compressor in the 1996 EPA/GRI Study. By using a control factor that substantially underestimates the methane emissions reduction potential for these sources, the agency arrives at a cost figure that is far higher than the true control costs for such devices.

We urge EPA to remedy this problem by conducting a study of emissions wellhead reciprocating compressors, which are poorly characterized by the current data. However, in lieu of recent and comprehensive data, we have attempted to estimate a more accurate cost estimate for controlling wellpad reciprocating compressors than the figure EPA cites in its TSD, even while EPA's Inventory does not provide us with the data to estimate total emissions or abatement factors from these units. To be conservative, we considered the range of emission control factors for

[39] *Id.* at 6-15 (Table 6-6).

reciprocating units based on reported values for other segments of the oil and gas industry. As noted above, these values ranged from 6.84 to 21.70 tons of methane per year per compressor. We selected the lowest emission control factor of 6.84, and, to add another layer of conservatism into our estimate, we reduced this number by an additional 50% to arrive at an emission control factor of 3.42 tons of methane per year per compressor.

Based on these control factors, we calculate a revised control cost of $742 for wellhead reciprocating compressors. When cost savings from conserved gas sales are taken into account, this figure drops to $497 per ton. Accounting for conserved gas revenues, the control cost for gathering and boosting reciprocating compressors drops to $12, and for processing sector units, the control cost is -$156, a net profit.

### ii. Methane Abatement Opportunity for Existing Centrifugal Compressors.

Based on data from EPA's 2011 Inventory, we estimate that 1,397[40] wet seal centrifugal compressors were operating in the U.S. oil and gas sector in 2009. Additional compressors were added between 2009 and August 23, 2011, the effective date of the 2012 NSPS, so again, this estimate is conservative. The 2011 Inventory estimates that these units emitted 546,338 tons of methane in 2009, as illustrated in Table 6 below.

**Table 6*****: Activity Counts and Aggregate Emission Estimates at Oil and Gas Sector Centrifugal Compressors***

| Existing Compressor Emission Estimates - Not Regulated by 2012 NSPS | | | | |
|---|---|---|---|---|
| **Equipment Type** | **Number of Devices** | **Emissions (tons/year) in 2009** | | |
| | | **Methane** | **VOC** | **HAP** |
| Existing Wet Seal Centrifugal Compressors (Processing) | 646 | 257,245 | 71,514 | 2,701 |
| Existing Wet Seal Centrifugal Compressors (Transportation) | 667 | 259,531 | 7,189 | 208 |
| Existing Wet Seal Centrifugal Compressors (Storage) | 84 | 29,563 | 819 | 24 |
| **Subtotal** | **1,397** | **546,338** | **79,522** | **2,932** |

VOC and HAP emission estimates were computed using conversion factors from EPA 2011 TSD, Page 6-2.

To arrive at the estimate of 535,237 tons of methane emitted, we used emission factors of 51,370 scfd per compressor in the processing segment, 50,222 scfd per compressor in the transmission segment, and 45,441 scfd per compressor in the storage segment. These emission factors appear in EPA's 2011 Inventory[41] and are based on calculations from a study conducted by ICF

[40] 2011 Inventory, Annex 3, Tables A-121 through A-122 (646 processing segment units + 667 transmission segment units + 84 storage segment units = 1,397 wet seal centrifugal compressors sector-wide). Although these tables included emissions data for centrifugal compressors at liquefied natural gas ("LNG") storage and import stations, they do not specify whether they are wet seal or dry seal compressors. Accordingly, we do not include those data in our estimates. In any event, aggregate methane emissions from wet seal centrifugal compressors in this sector are almost certainly higher than our estimates suggest.

[41] *Id.*

International in 2009.[42] They are conservative compared to EPA's Natural Gas STAR report, which indicates that wet seal emissions are more typically in the range of 40 to 200 scfm (57,600 to 288,000 scfd), as compared to dry seals that emit 0.5 to 3 scfm (720 to 4,320 scfd), or 1 to 6 scfm (1,440 to 8,640 scfd) for a two-seal system.[43] Using the higher range of emission factors cited in EPA's Natural Gas STAR report would substantially increase this emission estimate, so our analysis is conservative in this regard as well.

The 2009 ICF study also provided detailed breakdowns of the specific sources of emissions at centrifugal compressors in each segment of the oil and gas industry. According to these breakdowns, seal leaks accounted for 58.3% of emissions from wet seal centrifugal compressors in the processing segment, 41.0% of emissions from units in the transmission sector, and 33.9% of emissions from units in the storage sector.[44] Using these percentages, we reduced the 2011 Inventory's aggregate emission figures for wet seal centrifugal compressors in order to estimate the emissions attributable specifically to wet seal leaks. Table 7 illustrates these calculations..

**Table 7*: Aggregate Emission Estimates at Oil and Gas Sector Wet Seal Centrifugal Compressors- Seal Leaks Only***

| Existing Centrifugal Compressors-- Emissions Attributable to Wet Seal Leaks | | | | |
|---|---|---|---|---|
| **Equipment Type** | **Seal Leak % of Total** | **Emissions abated (tons/year)** | | |
| | | **Methane** | **VOC** | **HAP** |
| Existing Wet Seal Centrifugal Compressors (Processing) | 58% | 149,970 | 41,692 | 1,575 |
| Existing Wet Seal Centrifugal Compressors (Transmission) | 41% | 106,483 | 2,950 | 85 |
| Existing Wet Seal Centrifugal Compressors (Storage) | 34% | 10,010 | 277 | 8 |
| **Subtotal** | | **266,463** | **44,919** | **1,668** |

In the TSD for the 2012 NSPS, EPA provided baseline estimates for emissions from centrifugal compressors with wet and dry seals, respectively.[45] Comparing these figures, we calculate a per-unit 87.4% methane abatement potential by requiring existing wet seal compressors in the processing, transportation, and storage segments to be retrofitted with dry seals.[46] This abatement percentage reflects data for new compressors; leaks from existing compressors would likely be higher, and the abatement potential higher as well. Reports of control effectiveness for seal oil gas capture systems have also been higher than 87%.[47] We then applied the 87.4% abatement potential to each segment's emissions to compute a total methane reduction potential of 477,589 tpy from centrifugal compressors, along with co-benefits of 69,541 tpy in VOC emission reductions and 2,240 tpy in HAP emission reductions.

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[42] The results of this study are summarized in a memo prepared by ICF, attached as **Ex. 2**.
[43] EPA, *Lessons Learned from Natural Gas STAR Partners: Replacing Wet Seals with Dry Seals in Centrifugal Compress*ors (Oct. 2006), at 3, *available at* http://www.epa.gov/gasstar/documents/ll_wetseals.pdf.
[44] *See* Ex. 4 at 4-5.
[45] TSD at 6-5 (Table 6-3).
[46] *Id.* (1 – (28.6 tpy/228 tpy) = .874; 1 – (15.9 tpy/126 ypu) = .874).
[47] *See, e.g.*, BP and BGE, *Centrifugal Compressor Wet Seals Seal Oil De-Gassing & Control*, presented at 2014 Natural GasSTAR Annual Implementation Workshop,(May 2014) at 19, *available at* http://www.epa.gov/gasstar/documents/workshops/2014_AIW/Experiences_Wet_Seal.pdf (BP measured control effectiveness of over 99% on degassing unit employed on a high pressure compressor).

**Table 8*: Total Emission Reduction Opportunities at Oil and Gas Sector Centrifugal Compressors***

| Emission Abatement Potential - Replace Wet Seals with Dry Seals | | | | |
|---|---|---|---|---|
| **Equipment Type** | **% Abatement** | **Emissions abated (tons/year)** | | |
| | | **Methane** | **VOC** | **HAP** |
| Existing Wet Seal Centrifugal Compressors (Processing) | 87% | 131,158.25 | 36,461.99 | 1,377.16 |
| (Transportation) | 87% | 93,045.52 | 2,577.36 | 74.44 |
| Existing Wet Seal Centrifugal Compressors (Storage) | 87% | 8,746.71 | 242.28 | 7.00 |
| **Subtotal** | | **232,950** | **39,282** | **1,459** |

EPA estimated the control cost for dry seals on centrifugal compressors in the processing, transmission and storage segments to be $14 to 25 per ton of methane abated, without accounting for savings from recovered gas and reduced operating and maintenance costs.[48] Taking these savings into account, our recommended measures would result in a net profit of $206 per ton of methane abated in the processing segment. [49] Because transmission and storage facilities do not typically own the gas in their facilities, we did not calculate the cost for these segments that includes the revenue from conserved gas.

### iii. Methane Abatement Opportunity for New Compressors That Were Not Regulated in the Final Rule for the 2012 NSPS.

In the final 2012 NSPS, EPA did not set operational standards requiring emission controls for compressors located at oil and gas wellheads.[50] EPA concluded that such controls were not necessary because VOC emissions were typically low at these locations.[51] Methane emissions, however, are significant at wellhead compressors, and any regulatory approach that specifically targets methane should require emission controls at these units.

EPA estimated a total of 6,000 new wellhead reciprocating compressors installed each year, with aggregate seal leak emissions of 947 tpy methane, 263 tpy VOC, and 9.91 tpy HAP.[52] As discussed above, EPA's methane emission reduction factor of 0.158 tpy/unit for wellhead reciprocating compressors is drastically lower than the agency's estimates for similar reciprocating compressors in other segments of the industry and significantly underestimates emissions from wellhead compressors. Accordingly, for the reasons described above, we instead use a revised emission reduction factor of 3.42 tpy/compressor for these units. Based on EPA's estimates of 6,000 new wellhead reciprocating compressors each year, control measures for these units will reduce methane emissions by 20,520 tpy, with co-benefit reductions of 3,131 tpy VOC

[48] Based off data from Sections 6.3, 6.4 and 6.6 of the 2012 TSD at 6-1 to 6-3 ($40,720 (total annual cost for wet seal compressors) / 2,810 tpy methane = $14 per ton of methane abated). For the transmission and storage cost ($25), we used the relative emissions abatement for wet seals compressors in the 2011 TSD at 6-24 (Table 6-10).
[49] *Id.*
[50] 77 Fed. Reg. at 49,543.
[51] *Id.* at 49,498.
[52] TSD at 6-15 (Table 6-6). The agency estimated that no new centrifugal compressors would be installed anywhere in the oil and gas production sector, including at wellhead sites.

and 115 tpy HAP. As discussed on page 16 and 17 above, these measures entail a control cost of $742 per ton of methane abated without accounting for revenues from captured gas sales and $497 per ton when considering these savings.

Additionally, EPA's 2012 NSPS did not cover new compressors (either reciprocating or centrifugal units) located in the transmission and storage segments. The agency again concluded that VOC emissions were typically low at these locations, and that it needed additional time to consider cost-effective standards for them.[53] Once more, however, it is evident that methane emissions from these locations are significant and can be controlled with cost-effective measures.

EPA estimated that there are 199 new reciprocating compressors installed each year in the transmission segment, with a corresponding emission reduction potential of 423 tpy methane, 11.7 tpy VOC, and 0.35 tpy HAP.[54] For a rule requiring periodic replacement of rod packing systems at transmission segment units, EPA calculated a control cost of $77 per ton of methane reduced.[55] EPA also estimated that nine new reciprocating compressors will be installed each year in the natural gas storage segment, with a corresponding emissions reduction potential of 87 tpy methane, 2.4 tpy VOC, and 0.07 tpy.[56] EPA estimated costs of $104 per ton of methane to control emission from these units. [57]

The agency also declined to regulate rule new wet seal centrifugal compressors in the transmission and storage segments in the final 2012 NSPS. Using the TSD's emission factors, as well as its assumption that 14 new units will be installed per year, we estimate that 1,546 tpy methane could be reduced by requiring dry seals or gas capture systems at these compressors, as well as 43 tpy VOC and 1.3 tpy HAP. The agency estimated the control cost of regulating these units at $97 per ton of methane reduced, with a profit of $703 per ton when accounting for reduced operating and maintenance costs.[58]

**Table 9*: Emission Reduction Opportunities at New Compressors Not Regulated Under EPA's 2012 NSPS***

| Potential Emission Abatement from New Compressors Not Regulated by 2012 NSPS | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Equipment Type** | **Emission control factor (tpy/unit)** | | | **Number of new devices/Yr** | **Emissions abated (tpy)** | | |
| | **Methane** | **VOC** | **HAP** | | **Methane** | **VOC** | **HAP** |
| New Wellhead Reciprocating Compressors* | 3.42 | 0.0439 | 0.00165 | 6,000 | 20,520 | 3,131 | 114.9 |
| New Transmission Reciprocating Compressors* | 21.70 | 0.600 | 0.0178 | 199 | 423 | 11.7 | 0.35 |
| New Storage Reciprocating Compressors* | 21.80 | 0.060 | 0.0179 | 9 | 87 | 2.4 | 0.07 |
| New Transmission and Storage Centrifugal Compressors** | 110.00 | 3.06 | 0.09 | 14 | 1,546 | 43 | 1.3 |
| **Subtotal** | **Emission Abatement Compounds Each Year** | | | | **22,576** | **3,188** | **117** |

*Emission Estimates from EPA 2011 TSD, Table 6-6, Page 6-15. Wellhead methane factor was adjusted to 3.42 instead of .158 as explained in text

**Emission Estimates from EPA 2011 TSD, Table 6-8, p. 6-20. Note there is a typo in the EPA table. The category labeled Storage, included Transmission and Storage. The category labeled

[53] 77 Fed. Reg. at 49,498, 49,523.
[54] TSD at 6-15 (Table 6-6).
[55] *Id.* at 6-17 (Table 6-7). Because transmission and storage system operators do not own the natural gas they transport and store, respectively, there are no cost savings associated with the sale of conserved gas in these segments.
[56] *Id.* at 6-15 (Table 6-6).
[57] *Id.* at 6-17 (Table 6-7).
[58] *Id.* at 6-22 (Table 6-9).

Notably, these abatement figures account only for the first year that controls would be required at new compressors. After the second year, the total effective emissions reductions would double, as the new, cleaner compressors installed in the first year would continue to emit less than the units that would otherwise have been installed. With each additional year, these emission reduction benefits would continue to compound as new equipment is installed and the cleaner devices installed before that year continue to operate.

### D. Control Measures for Compressors Not Covered Under the 2012 NSPS: Anticipated Emission Reductions Based On 2014 Inventory Data.

EPA's compressor white paper provides industry-wide compressor activity counts and associated methane emissions from EPA's most recent inventory for 2014, covering the years 1990 to 2012. This 2014 Inventory estimates total methane emissions (including both seal leaks and fugitives) from existing reciprocating compressors at of 1,651,368 short tons per year ("tpy")[59] in 2012, reflecting an existing device count of 50,244.[60] The 2014 Inventory also estimates total methane emissions from existing centrifugal compressors (including both wet and dry devices) at 632,194 tpy[61] based on a total device count of 1,801.[62] Accounting for existing reciprocal and centrifugal compressors together, the 2014 Inventory estimated a total of 2,283,562 tpy of methane from these sources for 2012. Using EPA's 100-year global warming potential ("GWP") for methane of 21—a highly conservative value, as noted above—these emissions amount to nearly 43.5 million metric tons per year $CO_2$e. The up-to-date GWP figures currently recommended by the International Panel on Climate Change ("IPCC")[63] paint an even more dramatic picture, tabulating natural gas sector compressor emissions at over 74 million and 180 million metric tons per year $CO_2$e on a 20- and 100-year basis, respectively.

Using data on the 2014 Inventory as a baseline, and applying the emission reduction factors that we computed based on earlier data (a 63-80% reduction of seal leak emissions at existing reciprocating compressors and 87% reduction at existing wet-seal centrifugal compressors), we calculate that the recommended measures would reduce seal leak emissions from existing compressors by 537,479 tpy. Table 10 below breaks down these reduction estimates for existing reciprocating and centrifugal compressors.

[59] CWP at 20 (Table 3-9) (70,859+15,400+442,634+773,294+150,225+40,147+5,552 =1,498,111 MT * 1.1023 tons/MT = 1,651,368 tpy).
[60] *Id.* (35,930+136+5,624+7,235+1,012+270+37) = 50,244 reciprocating compressors.
[61] *Id.* (237,724+43,937+232,826+14,972+22,347+6,532+13,766+1,419 =573,523 MT * 1.1023 tons/MT= 632,194 tpy).
[62] *Id.* (658+248+659+66+70+29+64+7 = 1,801 centrifugal compressors).
[63] The IPCC's most recent GWP figures for methane from fossil sources are 36 on a 100-year basis and 87 on a 20-year basis when accounting for carbon-climate feedback effects. *See* IPCC, *Fifth Assessment Report: The Physical Science Basis* (2013), at 714, Table 8-7, *available at* http://www.climatechange2013.org/images/report/WG1AR5_Chapter08_FINAL.pdf.

**Table 10*****: Abatement Opportunities from Existing Gas Sector Compressors (2014 Inventory Data)***

| Emission Abatement Potential - Existing Compressors | | | |
|---|---|---|---|
| **Equipment Type** | **Emissions abated (tpy)** | | |
| | **Methane** | **VOC** | **HAP** |
| Existing Reciprocating Compressors | 304,576 | 37,128 | 1,356 |
| Existing Centrifugal Compressors | 232,903 | 45,617 | 1,695 |
| **Subtotal** | **537,479** | **82,745** | **3,051** |

This total aligns with our conservative estimate of 525,218 tpy in methane emission abatement from existing compressors based on data that was available to EPA at the time of the 2012 NSPS rulemaking.

### E. Summary

We conclude that, in total, the control measures we advocate will reduce methane emissions from existing gas sector compressors by 525,218 to 537,479 tpy and from new compressors by 22,576 tpy. As indicated earlier, we believe that these estimates are conservative in light of the very low emission factors EPA used in the 2011 Inventory; actual emissions may in fact be much higher, as the 2011 URS/UT study implies.

We used very conservative assumptions as described above to avoid debate about the significance of uncertainty in emission estimates and to avoid any reasonably identifiable possibility of overstating seal leak emissions from compressors. Even with these conservative assumptions, the recommended measures are warranted, as they reduce substantial amounts of emissions of methane, VOC, and HAPs, while either imposing minimal costs or generating a profit. Forgoing these conservative assumptions would result in substantially lower costs and higher methane capture rates, only strengthening the case for immediate regulation of these sources.

Moreover, we used data that either appeared in EPA's TSD for the 2012 NSPS or was available to the agency at that time in order to emphasize that EPA already has data available and compiled that shows that available pollution controls are cost-effective, feasible, and will reduce harmful pollution of methane and other pollutants substantially. We recommend that EPA simply update the existing TSD materials from 2012 to focus on methane and include new activity and cost data, then issue a rule that includes the measures we have recommended herein.

Lastly, we propose several additional approaches to methane regulation to supplement those we have already discussed. First, we support EPA's consideration of requiring piston rod replacement or realignment/refitting at reciprocal compressors on a periodic basis. We urge the agency to include this requirement in a final rule to optimize methane abatement. Second, in our discussion above, we recommend that operators be required to retrofit existing wet seal centrifugal compressors with gas capture systems that direct gas from seal oil degassing systems to compressor suction (or other beneficial use), or with dry seal systems. Finally, EPA must not delay a methane control rule that captures the majority of emissions by requiring the proven technologies adopted for some compressors under the 2012 NSPS while gathering data on other options. A rule including the recommended measures must be implemented as soon as possible while EPA explores other opportunities to reduce emissions from natural gas sector compressors.

## F. Responses to Charge Questions

- **Question 1:** We have presented summaries above on the quantity of emissions of methane (and other pollutants) from natural gas compressors. These estimates, as we have noted, use emissions data from EPA's 2012 and 2014 Inventories, as well as the data and analyses that were used to develop those Inventories. We have noted that some data sources suggest that actual emissions from compressor seal leaks may be much higher than the Inventories indicate, but have not adjusted the EPA's figures to reflect those alternate data sources. We there believe this is a very conservative analysis

  We are not aware of any studies suggesting that emissions from compressor seal leaks are overestimated in the Inventories.

  In general, the dataset for emissions from compressor seal leaks is fairly strong, with a number of studies confirming that emissions are substantial over the years. The exception is for compressors on wellpads, where all analyses cite a single measurement of a single compressor. We have highlighted this problem in multiple places in our comments.

- **Questions 2 – 5:** In a general sense, we believe that the white paper adequately characterized studies on emissions, the range of technologies for capturing emissions, emissions reductions from those technologies, and capital and operating costs for those technologies.

- **Questions 6 – 8:** We are not aware of emission capture technologies that were not described in the white paper, specific limitations on replacing wet seals with dry seals, or any limitation on the use of gas capture systems for wet seal compressors.

- **Question 9:** Gas capture systems are generally applicable to wet seals compressors. A recent report by BP describe these systems as "[s]imple, broadly flexible, and reliable."[64] Costs for these systems are low, and down time for installation is short. The design and operating principles of wet-seals centrifugal compressors are such that simple installations, using minimal moving parts and a simple critical orifice approach to manage pressures, can route gas from degassing drums to compressor suction.[65]

- **Questions 10 and 11:** We have no information on these matters.

- **Question 12**: Studies coordinated by EDF of emissions from natural gas gathering and processing facilities and natural gas transmission and storage facilities are underway. To our knowledge, the study of gathering and processing facilities will *not* differentiate emissions from compressor vents (the study will measure emissions from the entire facility). However, it is possible that this research may provide insight on emissions from compressors.

  We do not know of any current studies to measure emissions from compressor seals.

[64] *See supra,* n.47.
[65] *Id.*

## IV. Comments on Pneumatic Devices White Paper

### A. Introduction

Pneumatic equipment in the oil and gas industry uses pressurized gas to create mechanical action. In our comments, we focus specifically on pneumatic controllers, although the general category of pneumatic equipment also includes Kimray pumps. Pneumatic controllers, or "PCs," are automated instruments that control various process conditions of natural gas, such as liquid level, pressure, pressure difference, and temperature. Many PCs in the oil and gas sector use pressurized natural gas as their energy source and vent some quantity of that gas into the atmosphere in normal operation. These devices include continuously emitting devices (either high-bleed or low-bleed PCs), snap-acting or intermittent devices (which emit gas in periodic releases), and no-bleed devices, which are self-contained units that release gas to downstream pipelines rather than into the atmosphere. PCs that are powered by some source other than pressurized natural gas, such as electricity, solar power, or instrument air, also do not vent gas into atmosphere.

This section provides an analysis of control measures requiring operators to replace existing high-bleed and intermittent-bleed PCs with low-bleed devices. Our calculations demonstrate that these measures would achieve over 507,000 tpy of methane emission abatement at a control costs ranging from $25 to $208 per ton exclusive of savings from capture gas sales and reduced operating costs. Accounting for these revenues and savings, the measures described below would generate annual savings to operators in oil and gas production ranging from $270 to over $1000 depending on the type of PC at issue.

In this discussion that follows, we first characterize the emissions from PCs according to the best data available, and then assess the degree of abatement that can be achieved along with the potential cost of those measures. Next, we canvass flag a number of important considerations with regard to the Prasino Group's 2013 study of PC emissions in British Columbia. Finally, after summarizing our findings, we address the charge questions included in EPA's pneumatic devices white paper.

### B. Emissions from Pneumatic Controllers are Substantial, and Underestimated in Available Data

EPA's white paper for pneumatic devices includes recent methane emission estimates ranging from 962,637 short tons per year ("tpy") (based on data from EPA's Greenhouse Gas Reporting Program ("GHGRP," or "reporting program"))[66] to 1,125,369 tpy (based on estimates in EPA's 2014 GHG Emission Inventory).[67] The GHGRP estimate reflects only of a subset of industry data, since only facilities with calculated emissions over the reporting threshold are required report to emissions. Further, in the gas and oil production sector, only devices at wellpads are required to report emissions; PCs located at gathering and boosting facilities do not report data to the GHGRP. However, while the GHGRP data underestimates the true emissions from oil and gas sector PCs, it is nonetheless much more accurate than the 2014 Inventory estimates of PC emissions in the oil and gas production segments, as discussed in more detail below.

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[66] EPA, White Paper on Oil and Natural Gas Sector Pneumatic Devices (April 2014) ("Pneumatics White Paper") at 20 (Table 2-7). Here, and throughout these comments, we convert metric tons from the white paper to short tons for the sake of consistency across all segments of our analysis.

[67] *Id.* at 14 (Table 2-3).

Additionally, unlike the 2014 Inventory, the GHGRP reports emissions separately for high-, intermittent-, or low-bleed PCs. Below, we explain how we derive our estimates for PC emissions from the oil and gas production segments, on the one hand, and from gas transmission and storage, on the other hand.

### *i. Emissions from PCs in the Oil and Gas Production Segments*

Because PC emissions from oil production and gas production are combined in the GHGRP, we consider these sources together and treat them as one segment for the purpose of our analysis. GHGRP data make very clear that the 2014 Inventory significantly underestimates PC emissions from oil and gas production. The 2014 Inventory reports PC emissions from oil and gas production at 848,244 tons of methane (net) in 2012. By contrast, the GHGRP data shows estimates emissions from onshore oil and gas production PCs at 949,327 tons in 2012. As noted above, GHGRP data only captures a subset of emissions from these segments, but for the facilities that do report emissions to the GHGRP, data for PC emissions are superior to those reported in the 2014 Inventory.

Both the GHGRP and the Inventory use the same emissions factors to calculate aggregate PC emissions: each study traces back to the 1996 EPA/GRI for those values. However, the other factors used to calculate aggregate emissions—that is, activity data (e.g., the number of PCs of each type) and the percentage of methane in the composition of emitted gas—are certainly superior in the GHGRP, where each reporter counts controllers and uses its own gas composition data to calculate emissions. Furthermore, GHGRP data represent a far bigger sample of U.S. facilities than the activity data sampling used by the authors of EPA/GRI study, and is, of course, more current by over a decade and a half. Likewise, the use of actual gas composition by individual firms will be more accurate than any estimate based on an average composition by NEMS region, the method used in the EPA/GRI study and the 2014 Inventory. For these reasons, it is clear that GHGRP data is more accurate than the Inventory's estimates for the subset of wellpad PCs that report emissions through the reporting program. That the GHGRP is more accurate while capturing only a subset of emissions, and reports higher emissions from production PCs than does the 2014 Inventory, highlights the fact that the 2014 Inventory significantly underestimates these emissions.

In 2103, a group of researchers led by David Allen at the University of Texas found that actual PC emissions are 29 percent and 270 percent higher than the GHGRP's emission factors for intermittent-bleed and low-bleed PCs, respectively.[68] The measurements in this University of Texas report (which we refer to hereafter as Allen, *et al.*) are much more current those that appear in the 1996 EPA/GRI study, which provide the basis for the GHGRP emissions factors. Moreover, Allen, *et al.* measured emissions from over 300 PCs,[69] while the EPA/GRI study

[68] *See* Allen, *et al.*, Measurements of methane emissions at natural gas production sites in the United States, Proceedings of the National Academy of Sciences 110:44 (Oct. 29, 2013) at 17,768-17,773, *available at* http://www.pnas.org/content/110/44/17768.full.pdf+html (supplemental appendices and tables *available at* http://www.pnas.org/content/suppl/2013/09/11/1304880110.DCSupplemental/sapp.pdf).
[69] *See* Allen, *et al.*, supplemental appendices and tables, Table S2-1.

measured only around 60 units.[70] Hence, for these two reasons, we consider the Allen, *et al*. emissions factors to be more accurate than those listed in the 1996 EPA/GRI study. Since GHGRP data can be separated into emissions for high-bleed, intermittent-bleed, and low-bleed PCs, we can then correct these data using the more accurate emissions factors from Allen, *et al.* by increasing the emissions from intermittent-bleed and low-bleed PCs by 29 percent and 270 percent, respectively. After this adjustment, total emissions from wellpad PCs that report emissions to the GHGRP were 1,255,865 tons of methane in 2012, 48% higher than the value from the 2014 Inventory. Table 11 below illustrates our revised estimates.

**Table 11*: Oil and Gas Production PC Emissions Reported to GHGRP for 2012 and Corrected with Allen,* et al*.'s Emissions Factors***

| **Bleed type** | **Emissions (Tons $CH_4$)** | **Emission Factors (scfh)** | | **Emissions (Tons $CH_4$)** |
|---|---|---|---|---|
| | GHGRP Reported | GHGRP[71] | Allen *et al.*[72] | GHGRP Corrected |
| Low | 45,113 | 1.39 | 5.1 | 165,521 |
| Intermittent | 644,295 | 13.5 | 17.4 | 830,425 |
| High | 259,918 | 37.3 | - | 259,918 |
| **TOTAL** | **949,327** | | | **1,255,865** |

#### *ii. Emissions from PCs in the Natural Gas Transmission and Storage Segments.*

While the 2014 Inventory reports 275,005 tons of methane emissions from PCs in the natural gas transmission and storage segments, only 13,310 tons were reported to the GHGRP. As discussed above, only larger facilities report emissions to the GHGRP; as such, we assume that the GHGRP is underestimating emissions from transmission and storage PCs, since controllers in those segments tend to be located at facilities that fall below the GHGRP threshold. Of the two reports, the 2014 Inventory value is likely the more accurate estimate of emissions from transmission and storage PCs, since the GRI/EPA study on which it was based was designed to estimate emissions from PCs nationwide, rather than simply a subset of PCs that covers larger emitters only. However, unlike the 2014 Inventory, the GHGRP data allows for emissions estimates based on each bleed type of PC. Accordingly, while we use the Inventory data as the starting point to estimate emissions from PCs in these segments, we rely on the GHGRP's ratios of different bleed-types to apportion the percentage of those emissions attributable to each type of device.

### C. The Methane Abatement Potential from Controlling Emissions at High- and Intermittent-Bleed PCs is Substantial

The pneumatics white paper does not include total methane abatement estimates, but only estimates of total emissions from PCs in each segment and estimates of abatement potentials for individual devices. Below, we present a methodology that calculates a methane abatement potential of approximately 508,000 tons from emission controls at high- and intermittent-bleed

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[70] *See* EPA/GRI, Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices (June 1996), Section 4.1.2, *available at* http://www.epa.gov/gasstar/documents/emissions_report/12_pneumatic.pdf.
[71] 40 C.F.R. Pt. 98, subpart W, Table W-1A.
[72] Allen, *et al*,. supporting information at S-31.

PCs. The estimates are shown in the table on the following page, and we describe below section assumptions we used in our abatement computations.

EPA's 2012 subpart 2012 NSPS required VOC emission controls for PCs at all new oil and gas production and gas processing facilities. The agency estimated emission control benefits of 25,273 tpyVOC, with co-benefits of 90,910 tpy methane and 954 tpy HAPS.[73] EPA estimates in its TSD that the rule would cover 13,647 devices per year.[74] However, the agency declined to issue a concurrent or subsequent rule regulating emissions from existing high-bleed devices, which currently amount to some 428,000 tons per year.[75]

The final NSPS rule also did not apply to intermittent-bleed ("IB") PCs, which EPA did not discuss in detail in the pneumatics white paper despite annual emissions of around 830,000 tons from existing devices.[76] Continuous bleed controllers (including low-bleed units) and IB devices serve similar, and in many cases identical, purposes. The American Petroleum Institute ("API") has stated that "[a]chieving a bleed rate of < 6 SCF/hr [*i.e.,* the average vent rate required of new, continuous-bleed controllers] with an intermittent vent pneumatic controller is quite reasonable since you eliminate the continuous bleeding of a controller."[77] PCs emitting less than 6 scfh (including both continuous-bleed and IB devices) can serve many of the functions of higher-emitting intermittent devices, which could therefore be replaced with low-bleed controllers. There are many applications for PCs, as well as a wide variety of parameters for controller design, such as pressure, extreme temperature performance, response time, flow rate, corrosiveness of fluids, and more. As such, there are many controllers of both continuous-bleed and IB design on the market, including many emitting below 6 scfh.[78] Indeed, the emissions factor for IBs in natural gas transmission is 2.35 scfh,[79] well below 6 scfh.

Our estimates herein are focused on the additional methane abatement potential that can be achieved by converting existing oil and gas sector high-bleed and intermittent-bleed PCs to low-bleed devices, a control requirement that should have been included in the 2012 NSPS rule but was not.[80] We conservatively estimated that 95% of existing high-bleed PCs could be replaced with low-bleed PCs. While EPA's Natural Gas STAR Program Partners reports that

[73] EPA, *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Technical Support Document for Proposed Standards* (July 2011) (hereafter, "TSD") at 5-25 (Table 5-12).
[74] *Id.*
[75] *See* Table 12, *infra.*
[76] *See* Table 13, *infra.*
[77] API, *Technical Review of Pneumatic Controllers by David Simpson, P.E.* (October 14, 2011), cited in *Rebuttal Statement Of The Sierra Club, Natural Resources Defense Council, Earthworks Oil And Gas Accountability Project And Wildearth Guardians,* available at ftp://ft.dphe.state.co.us/apc/aqcc/REBUTTAL%20STATEMENTS,%20EXHIBITS%20&%20ALT%20PROPOSAL%20REVISIONS/Conservation%20Group/Conservation%20Groups%20-%20REB%20Exhibits.pdf.
[78] For discussion of low-bleed devices, including some specific low-bleed devices, *see* EPA, *Lessons Learned from Natural Gas STAR Partners: Options For Reducing Methane Emissions From Pneumatic Devices In The Natural Gas Industry* (Oct. 2006) at 2, *available at* http://epa.gov/gasstar/documents/ll_pneumatics.pdf.
[79] 40 C.F.R. Pt. 98, subpart W, Table W-3.
[80] As discussed on pages 29-30 below, data available to EPA at the time of the 2012 NSPS rulemaking supported regulations for existing PCs.

approximately 80% of high-bleed PCs can be replaced or retrofitted with low-bleed devices,[81] experience in the Denver-Julesburg ("D-J") Basin in Colorado suggests that replacing nearly 100% of high-bleed controllers with low-bleed devices is feasible. Colorado required operators to replace existing high-bleed controllers in the urban portions of the D-J Basin in 2009.[82] The rule contained provisions allowing operators to keep high-bleed controllers in service if they showed that doing so was necessary for "safety and/or process purposes."[83] No operator requested such an exemption,[84] and there is no evidence in the record that these requirements have caused any operational problems. Accordingly, we use Colorado Department of Public Health and the Environment's ("CDPHE") estimate that 95% of high-bleed devices can be replaced with low-bleed units.[85] We use this estimate for oil and natural gas production PCs and natural gas transmission and storage PCs.

In its March 2014 report co-authored with EDF, ICF International estimated that 75% of intermittent-bleed PCs in oil and gas production function as dump valves on separators at well sites and did not recommend replacing these PCs with lower-emitting devices.[86] To set a lower limit to our calculated abatement potential, we use this figure to estimate that 25% IB units in the production sector can be replaced with low-bleed PCs.[87] For the natural gas transmission and storage segments, IB PCs emit at a very low rate, and we do not consider replacing them in these calculations.

We used the best available emissions factors for PCs of each bleed type[88] to estimate the potential emissions abatement from replacing high- and intermittent-bleed PCs with low-bleed PCs. To estimate emissions from PCs in oil and gas production, we use the figures from the GHGRP as adjusted by the emissions factors from Allen, *et al.*, as well as the percentage breakdown between bleed types from the GHGRP data. For emissions from PCs in natural gas transmission and storage, we use the data from the 2014 Inventory and assume that the portion of emissions originating from each bleed type is the same as indicated in the GHGRP data.

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[81] EPA, *supra* n. 78, at 2.

[82] *See* 5 C.C.R. § 1001-9 XVIII (2009), *available at* https://www.sos.state.co.us/CCR/GenerateRulePdf.do?ruleVersionId=2772&fileName=5%20CCR%201001-9.

[83] *Id.* § 1001-9 XVIII.C.3 (2009).

[84] Email from Daniel Bon, CDPHE, to David McCabe, Clean Air Task Force, 1 November 2013, attached hereto as **Ex. 3**.

[85] Colorado Air Quality Control Commission, *Cost-Benefit Analysis for Proposed Revisions to AQCC Regulations No. 3 and 7* (Feb. 2, 2014), at 32, *available at* ftp://ft.dphe.state.co.us/apc/aqcc/COST%20BENEFIT%20ANALYSIS%20&%20EXHIBITS/CDPHE%20Cost-Benefit%20Analysis_Final.pdf.

[86] EDF/ICF International, *Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries* (March 2014) at 3-15, *available at* http://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.

[87] We note that it may not be necessary to replace an IB PC with a continuously emitting low-bleed device – the replacement can be intermittent bleed so long as it emits no more than a low-bleed device (6 scfh).

[88] For low- and intermittent-bleed PCs in petroleum and natural gas production, we used the Allen, *et al*. emissions factors (5.1 and 17.4 scfh, respectively). For other PCs, we used the GHGRP emissions factor (37.3 scfh for high-bleeds in petroleum and natural gas production; ).

The resulting potential abatement is shown in the tables below. In summary, we compute an emission control benefit of 507,286 tpy of methane, with co-benefits of 96,115 tpy of VOC emissions and 3,198 tons per year of HAP emissions.[89] The control cost of these measures ranges from approximately $25 to$208 per short ton of methane depending on the segment and type of pneumatic controller being replaced, without accounting for profits from the sale of captured gas or reduced operating and maintenance costs. If captured gas sales and operating cost reductions are included, economic attractiveness of these measures improves; in fact, in most cases, the control measures will generate positive cash flow for operators. The tables that follow illustrate the emission abatement potential from these control measures.

**Table 12*: Emission Abatement Potential of Converting PCs from High-Bleed to Low-Bleed***

| Industry Segment | Current Emissions From High-Bleed Controllers | High-bleed emissions | Low-bleed emissions | Percent of High-Bleed converted to Low-Bleed | Emissions Abated | Percent Emissions Abated |
|---|---|---|---|---|---|---|
| | tpy | scf/hour/ device | scf/hour/ device | | tpy | |
| Oil and Gas Production | 259,918 | 37.3 | 5.1 | 95% | 213,161 | 82% |
| Gas Transmission & Storage | 167,754 | 18.2 | 1.37 | 95% | 147,370 | 88% |
| **Totals**[90] | | | | | 360,531 | 84% |

**Table 13*: Emission Abatement Potential of Converting PCs from Intermittent-Bleed to Low-Bleed***

| Industry Segment | Current Emissions From Int.-Bleed Controllers | Int.-bleed emissions | Low-bleed emissions | Percent converted to Low-Bleed | Emissions Abated | Percent Emissions Abated |
|---|---|---|---|---|---|---|
| | tpy | scf/hour/ device | scf/hour/ device | | tpy | |
| Oil and Gas Production | 830,425 | 17.4 | 5.1 | 25% | 146,756 | 18% |

[89] The ratio of methane to VOC and HAP is based on the values in the 2012 TSD at 5-25 (Table 5-12).
[90] We do not address PCs in the gas processing segment due to very low emissions.

**Table 14*: Overall Emission Abatement Potential from PC Control Measures (tons per year)***

| Emissions Type | Current Methane Emissions | Overall Abatement Percent | Methane Abatement | VOC Abatement | HAP Abatement |
|---|---|---|---|---|---|
| | tpy | | tpy | | |
| Oil and Gas Production Segments | 1,255,865 | 29% | 359,916 | 91,944 | 3,428 |
| Transmission and Storage Segment | 275,005 | 54% | 147,370 | 4,171 | 126 |
| **Totals** | 1,530,870 | 33% | 507,286 | 96,115 | 3,554 |

By controlling 95% of high-bleed PCs and 25% of IB PCs, over 507,000 tpy of methane pollution can be avoided, or about one-third of methane from all types of PCs.

### D. Control Costs to Convert Existing High-Bleed Pneumatic Controllers to Low-Bleed Devices

The cost to replace a high-bleed and intermittent-bleed pneumatic controllers with low-bleed controller is very modest. Here, we estimate the cost for retrofitting an existing PC with a new PC by considering the full cost of the replacement controller. Our estimate is conservative because we assume in all cases that the existing higher emitting controller would have continued operating for another ten years, the full lifetime of the new device. We do not account for the fact that a portion of the higher-emitting devices will have already reached the end of their useful lives by the time the replacement is required.

Very recently, the CDPHE estimated the cost of replacing high-bleed controllers in this manner.[91] Based on labor and equipment costs of $1,420 per device replaced, CDPHE calculated a replacement cost of $169/yr/device, assuming that costs were annualized over fifteen years at a 5% interest rate.[92] ICF cited industry feedback in reporting that the total replacement cost per device could be as high as $3000.[93] As an upper limit, we annualize the ICF figure over10 years at a 7% interest rate to arrive at an annual control cost of $427/yr/device. These equipment costs bracket EPA's estimate in the OOOO TSD of $2,554 for a new low-bleed controller.[94] In some cases, the cost can be as low as $700 per new controller,[95] although the estimates we present in the table below use CDPHE's $1,420 per device (or $169/year) figure as the lower bound. These costs apply to replacing either a high-bleed or intermittent-bleed PC with a new low-bleed device.

[91] This analysis was not described in the white papers.
[92] Colorado Air Quality Control Commission, *supra* n. 85, at 32.
[93] EDF/ICF International, *supra* n. 86, at 3-16.
[94] TSD at 5-14.
[95]EPA and Occidental Oil & Gas Corporation, *Methane Recovery from Pneumatic Devices, Vapor Recovery Units and Dehydrators* (Oct. 6, 2005) at 8, *available at* https://www.globalmethane.org/documents/events_oilgas_20051006_methanerec_pd_vru_dehy.pdf.

EPA's NSPS estimated that converting from a high-bleed PC to a low-bleed controller would reduce methane emissions by 6.65 tpy for devices in the production and processing segment and 2.96 tpy for devices in the transmission and storage segments.[96] We calculate the methane emissions abatement for replacing an IB PC with a low-bleed PC to be 2.28 tpy per device based on the emission factors cited in Allen, *et al*. Without considering the increased revenue could obtain by selling gas that would have otherwise been vented, the control measures described above have very reasonable abatement costs of $25 to $208 per ton of methane, depending on the industry segment and the type of controller being replaced. Table 15 below provides these cost control figures. These costs per ton of methane abatement are well below the harm to society caused by a ton of methane emissions, which EPA economists recently estimated at $970 per metric ton (or $879 per short ton).[97]

**Table 15*: Abatement Costs for Pneumatic Controller Replacement***

| Switch from High- to Low-Bleed Pneumatic Controllers | Annual Cost per Device | | Methane reduced per component | Abatement Cost ($/short ton) | |
|---|---|---|---|---|---|
| | Low ($/year) | High ($/year) | ton / year | Low | High |
| Oil and Gas Production | $169 | $427 | 6.65 | $25.41 | $64.21 |
| Transmission and Storage | | | 2.96 | $57.09 | $144.26 |
| **Switch from Intermittent- to Low-Bleed Pneumatic Controllers** | **Annual Cost per Device** | | **Methane reduced per component** | **Abatement Cost ($/short ton)** | |
| | **Low ($/year)** | **High ($/year)** | **ton / year** | **Low** | **High** |
| Oil and Gas Production | $169 | $427 | 2.28 | $82.44 | $208.29 |

When accounting for increased revenue from sales of conserved gas that would otherwise have been emitted, CDPHE analysis shows that replacing high-bleed controllers with low-bleed controllers has a negative annual cost (a saving of over $1,000 per year, assuming a gas price of $3.50/Mcf).[98] We note that these revenues would be available to operators in oil and gas production only, since operators of transmission and storage facilities do not own the gas they transport or store. For production segment operators, the payback period for this replacement is about 14 months. For replacement of an IB controller with a low bleed controller, using the cost figures from the CDPHE analysis but adjusting for the smaller emissions reductions and additional revenues for this case, we calculate net savings of approximately $270 based on the CDPHE's estimates.

Using more conservative cost and the revenues from the resale of captured gas and reduction in operating costs, we still find that conversion from high-bleed to low-bleed devices results in net

[96] TSD at 5-6 (Table 5-2). Using the emissions factors from Allen, *et al.* would result in slightly smaller emissions abatement from high-bleed replacement.
[97] *See* Marten, *supra* n. 17.
[98] Colorado Air Quality Control Commission, *supra* n. 85, at 32-33.

savings for production segment operators. The 2014 ICF report concluded the conversion from a high-bleed controller to a low-bleed controller, even at a cost of $3,000 per device, resulted in an overall savings: "Although there are lower cost estimates from Gas STAR and vendors, this measure assumed a cost of $3,000 per replacement based on industry comments. Both options yield a greater than 90% reduction. This yields a reduction cost of -$3.08/Mcf of methane for replacement of high bleed pneumatics . . . ."[99]

### E. Device Classification Issue in the 2013 Prasino Group Study

The Prasino Group's 2013 study of emissions from pneumatic controllers is described in the pneumatics white paper. However, the white paper description of the study omits a few key aspects of the Prasino study. While the 2012 NSPS rulemaking, GHGRP, and calculations underlying the 2014 Inventory all use an emissions factor for high-bleed PCs of 37.3 scf/h natural gas, the Prasino study reports that a "generic high-bleed controllers" actually emits only 9.2 scf/h.[100] Yet the white paper fails to note that Prasino includes a number of PCs in that were designed to emit below 6 scf/h—and thus considered low-bleed units– but were actually emitting at some level above 6 scf/h:

> Devices that were determined to be high bleeding (i.e. bleed rate >0.17 $m^3$/hr [6 scf/h]) were grouped together in the analysis. If the calculated mean bleed rate was larger than the threshold, the device was included in the analysis, and if the calculated mean bleed rate was smaller than the threshold, the device was excluded from the analysis for determining a generic bleed rate. Certain controllers that are considered low-bleeding according to WCI or manufacturer specifications actually bled above the low bleed threshold and were therefore included in the analysis.[101]

The Prasino Group study results raise an important problem: PCs designed to emit less than 6 scf/h are considered low-bleed PCs but may, in fact, emit more in real operations in the field due to factors such as excess wear, installation with incorrect supply pressure, etc. The Prasino results show that this problem can be common. For example, the Prasino measurements show that the Fisher 2680 and L2 level controllers, which have manufacturer specified bleed rates well below the threshold rate of 6 scf/h, both emit gas at average rates significantly higher than the threshold. Prasino measured 32 Fisher 2680 units, which have a specified bleed rate of 0.04 $m^3$/h (1.4 scf/h), and found average bleed rates of 0.268 $m^3$/h (9.5 scf/h).[102] They also measured 48 Fisher L2 controllers, which have a specified bleed rate of 0.06 $m^3$/h (2.1 scf/h), and found average bleed rates of 0.264 $m^3$/h (9.3 scf/h).[103]

While the excess pollution from these controllers is a significant concern,[104] a large body of evidence, including the 1996 GRI/EPA study and GasSTAR data and reports,[105] shows that

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[99] EDF/ICF International, *supra* n. 86, at 3-16.
[100] Pneumatic Controller White Paper at 24 (Table 2-9).
[101] Prasino Group, *Final Report For Determining Bleed Rates for Pneumatic Devices in British Columbia* (Dec. 18, 2013), at 15, available at http://scek.ca/sites/default/files/ei-2014-01-final-report20140131.pdf.
[102] *Id.* at 14, 30.
[103] *Id.*
[104] We note that the same phenomenon is apparent in the data from Allen, *et al.*, which reported that low-bleed PCs were venting 5.1 scf/h, 270% more gas than EPA's emissions factors predict.

emissions from high-bleed controllers are typically much higher than these rates.[106] Indeed, the manufacturers' specifications for high-bleed PCs listed in the Prasino study show that many high-bleed units are designed to emit at far higher rates.[107] The problem of excessively high emissions from PCs that are designed to emit at very high rates should not be obscured or made to appear less severe by averaging emissions from low-bleed controllers emitting excessively alongside high-bleed controllers.

Because of the design of the Prasino study, it is not appropriate to consider it when evaluating the merits of replacing high-bleed PCs with low-bleed PCs. Namely, Prasino included PCs in their results that would not be targeted by a typical effort to replace high-bleed PCs. However, the Prasino study does highlight the issue of excess emissions from low-bleed PCs. For example, as we have discussed, the study showed that the actual emissions from Fisher 2680 and L2 level controllers are 6.7 and 4.4 times higher than their specified values. The excess pollution from these devices suggests that EPA should also be evaluating technologies to replace PCs that bleed any amount of natural gas into the atmosphere, such as electronic devices. We discuss this further in our response to the white paper's charge questions.

Finally, we note that Section 2.3.4 of the Prasino Group Study includes a useful discussion of the errors, uncertainty, and biases involved in developing this lower emission factor.[108] Factors that may have contributed to a lower emission factor include back pressure on the control device imposed by the meter used to measure emissions and exclusion bias from non-random sampling location choice, since permission was required by operators to conduct testing. This could have resulted in directed sampling in areas with less high-bleed devices.

### F. Summary

Using existing data from the GHGRP and the EPA'S 2014 GHG Inventory, we calculate a methane abatement opportunity of 507,286 tpy from replacing high- and intermittent-bleed pneumatic controllers with low-bleed pneumatic controllers in specified segments of the oil and gas industry. The cost of this abatement varies between segments and for difference pneumatic controller types, but all of the measures are cost-effective using current technology, and abatement for PCs in oil and gas production generate net profits for operators due to potential revenue from conserved gas sales.

Additionally, we support EPA's consideration of measures that would require operators to replace continuous bleed controllers with zero-bleed PCs, units powered by instrument air, or solar powered systems wherever technically feasible. However, EPA must not delay developing and

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The average emissions from low-bleed unit is only slightly below the 6 scf/h threshold, strongly suggesting that a significant number of the low-bleed PCs measured by Allen, *et al.* were emitting at rates greater than 6 scf/h.

[105] *See, e.g.*, http://www.epa.gov/gasstar/tools/recommended.html#pneumatics.

[106] For example, third party verification of emissions of 18–22 scf/h was measured for 148 controllers from three manufacturers in a high-bleed controller retrofit project by Chesapeake Energy registered with the American Carbon Registry. *See* http://americancarbonregistry.org/mount_acr/acr/carbon-registry/projects/chesapeake-mizer-pneumatic-retrofit-project/CHES-PNEU-2011-03-31.pdf (hereafter "Chesapeake retrofit project") at 31.

[107] *See* Prasino Group, *supra* n. 101, at Appendix A.

[108] *See id.* at Section 2.3.4.

implementing a methane control rule that would require the measures described in our analysis while the agency gathers data on these other options. EPA must immediately move forward with rulemaking that requires replacement of all high-bleed controllers with zero-bleed controllers when feasible and with low-bleed controllers where technically possible, and, as a second and separate rulemaking step, examine the incremental cost and feasibility of replacing all continuous bleed controllers with zero-bleed devices, instrument air controllers, or electronically-powered systems.

### G. Charge Questions for Reviewers

**1.** The white paper did not adequately describe the Prasino Group study from 2013. As explained above, this study averages together emissions from low-bleed PCs that emit methane at rates greater than their operationally specified rates with emissions from high-bleed controllers, which typically emit at rates much higher than those observed at even the worst performing low-bleed PCs in the study. As such, the Prasino study, while raising important issues, is not appropriate for evaluating emissions of high-bleed controllers as that term is typically used, nor is it appropriate for quantifying the benefits of replacing high-bleed controllers with lower-emitting devices.

**2.** The variation in measured emissions from PCs across different studies is due in part to inconsistent definitions of PC bleed types. For instance, we have described how the Prasino study included a significant number of low-bleed PCs emitting at rates higher than those specified by manufacturers in their "high-bleed" dataset. This approach lowers their average emissions rate for "high bleed controllers" significantly.

**3.** The white paper described a variety of technologies available to reduce emissions, but described some too narrowly. For example, electronic control instrumentation is described in section 3.1.4. While solar cells may provide an excellent source of electrical power for this type of instrumentation, other options include grid power, which may be close at hand given the development of oil and gas in populated areas in recent years, and power from thermoelectric generators[109] or small onsite gas generators. Furthermore, retrofit kits are available to reduce emissions from some high-bleed PCs.[110] These options are not described in the white paper, and the agency should evaluate their availability and efficacy.

**4.** As explained above, we believe that non-emitting technologies such as zero-bleed controllers, instrument air devices, and electronically control systems should be required whenever they are feasible. The reports that emissions from low-bleed controllers are higher than expected from manufacturer specifications (the Prasino Group study) and broad emissions factors (Allen, *et al*.) reinforce the need to examine non-emitting technologies. However, as stated above, EPA must not delay a methane control rule that captures the majority of emissions from oil and gas sector PCs while gathering data on these non-emitting options. EPA must immediately move forward with rulemaking to replace high-bleed controllers with low-bleed units while encouraging or requiring non-emitting options where feasible.

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[109] *See, e.g.*, http://en.wikipedia.org/wiki/Thermoelectric_generator#Uses.

[110] For example, Mizer valves used in the Chesapeake retrofit project. *See* Chesapeake retrofit project at 9.

5. While we cannot comment on the prevalence of different types of pneumatic controllers and non-emitting technologies in the field, or on the particular activities that require the use of high-bleed PCs, we reiterate that the industry response to the 2009 Colorado rules demonstrates that applications truly requiring high-bleed PCs are quite rare indeed. While the 2009 rules allowed operators to request an exemption from the retrofit requirement, not a single exemption request was received by CDPHE.

6. We have no response to this charge question at this time.

7. We have no response to this charge question at this time.

8. Given the abundant fuel available at oil and gas facilities and the wide variety of natural gas- powered compressors and generators available on the market, instrument air systems could easily be developed to match the compressed air requirements of any facility at a reasonable cost. However, the great bulk of emissions from pneumatic valve and controller systems come from the controllers themselves, as opposed to actuators. Given the advances in electronics, electronic control systems should be considered for many PC applications, and may be more appropriate and result in lower emissions than instrument air systems for many applications given very low power requirements of electronics. In spite of this, EPA and the Natural GasSTAR program have not summarized the state of this technology for many years. We strongly urge them promptly to do so.

9. We are aware that EDF and the University of Texas are currently studying methane emissions from PCs in the oil and gas sector. We are not aware of other ongoing research on this particular issue apart from this.

## V. Comments on the Liquids Unloading White Paper

The vast majority of gas wells co-produce liquids, including both hydrocarbons and water. As gas wells age, gas rates decline and gas velocity up the well declines to the point that it cannot lift these liquids, which then accumulate in the wellbore. Liquid loading can impair gas production rates or arrest gas flow completely. Once the accumulated liquids are removed from the wellbore, there is less backpressure on the gas formation, allowing gas flow to resume, or resume at a higher rate. For this reason, gas well operators have been voluntarily investing in methane abatement technology for many years, with the primary goal of improving gas well production performance.[111]

Liquids accumulation is an extremely common occurrence, and liquids unloading is correspondingly a common practice. In comments on the 2011 NSPS proposal, the American Petroleum Institute asserted that all gas wells producing 90 Mcf of gas (15 BOE or less) or less

[111] There are hundreds of Oil and Gas Sector technical publications written on methods to increase gas production by optimizing gas well deliquification. Many of these publications include economic assessments of improved profitability. The most efficient location to access these publications is the OnePetro online library of technical literature for the oil and gas exploration and production ("E&P") industry. OnePetro at www.onepetro.org. OnePetro contains 172 technical publications on gas well deliquification and 846 technical publications on liquids unloading, 780 papers on plunger lifts, and hundreds of other papers on other artificial lift methods for gas wells.

per day "are either impaired by liquids accumulation or are using a deliquification method to produce."[112] In that comment, API relied on 2009 EIA data to conclude that 73% of all gas wells, or 338,056 wells, fell into this category.[113] In 2012, API and ANGA surveyed 59,648 wells and, on the basis of this survey, concluded that in 2011, 268,609 wells, or 55% of all gas wells, proactively unloaded liquids[114].

Liquids can be unloaded through a variety of techniques. Most basically, the well can be simply vented, sometimes referred to as a "blowdown." A typical operating configuration has produced fluids flowing from the well into pressurized surface equipment. To unload through venting, the well is instead allowed to flow to a pit or tank at atmospheric pressure, removing back-pressure from the surface equipment. The increased pressure differential between the formation and the surface allows more gas to flow at a higher velocity and push accumulated liquids out of the well.

A more sophisticated approach is to use a plunger lift. A plunger lift is a simple and common artificial lift method used to efficiently lift liquid out of a well to optimize gas well production rates. Use of plunger lift systems can also produce a co-benefit of methane abatement. The main practical advantage of the plunger lift system is that it does not require electricity, and so can be installed at well sites that do not have power. A plunger lift system is powered by the natural gas pressure that builds up in the casing tubing annulus. Installation of a plunger lift generally increases gas production by 10%. Plunger lift performance can be improved through smart automation, which can bring the production increase up to 20%. The API/ANGA study estimates that of the 268,609 wells that underwent liquids unloading in 2011, 28,863 vented, 174,743 used plunger lifts, and 65,003 used other artificial lift methods.[115]

Plunger lifts are only one of many available artificial lift technologies—numerous additional systems can be used as well, including:

- Pumping techniques, such as progressing cavity pumps, hydraulic pumps, beam pumps, and electric submersible pumps
- Chemical methods, such as soap sticks
- Gas lift
- Velocity tubing
- Compression

### A. Emissions from Liquids Unloading

Liquids unloading through venting or plunger lifts can emit significant methane, VOC, and other pollutants. Emissions are inevitable for simple blowdowns. For plunger lifts, although API/ANGA data indicates that the majority of plunger lift installations (79%) have no

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[112] American Petroleum Institute (API), *Comments to U.S. EPA on Docket ID No. EPA-HQ-OAR-2010-0505* (Nov. 30, 2011), *available at* http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-4266.
[113] *Id.* (citing http://www.eia.doe.gov/pub/oil_gas/petrosystem/us_table.html).
[114] API/ANGA. *Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production Summary and Analysis of API and ANGA Survey* (Sept. 21, 2012), *available at* http://www.api.org/~/media/Files/News/2012/12-October/API-ANGA-Survey-Report.pdf.
[115] API/ANGA at 13-14.

emissions,[116] 21% are operated in a way that still releases appreciable pollution. The white paper summarizes the API/ANGA data on liquids unloading emissions together with two other estimates of national unloading emissions: the 2014 GHG Inventory and the 2013 GHG reporting rule data. The 2014 Inventory and GHGRP emission factor estimates, however, are informed by the API/ANGA data.[117] The white paper also discusses the evidence Allen et al. collected about unloading emissions through direct measurement of several wells.

**Table 16*: Summary of Liquid Unloading Methane Emissions***

| | API/ANGA | GHGI[e] | GHGRP[d] | Allen |
|---|---|---|---|---|
| # Wells with Unloading Emissions (total) | 65,669 | 60,810 | 58,663 | |
| plunger lift | 36,806 | 23,503 | 32,252 | |
| venting | 28,863 | 37,307 | 26,411 | |
| Total Unloading Methane Emissions (short tons per year) | 352,366 | 301,554 | 304,651.5 | |
| Methane Emissions per well (avg, all wells w/emissions), tpy | 5.37[b] | 4.96[b] | 5.19[b] | 6.39 |
| Methane Emissions per plunger lift well with emissions, engineering estimate, tpy | [a] | 5.58 | 4.1 | |
| Methane Emissions per vented well, engineering estimate, tpy | [a] | 4.6 | 3.4 | |
| Methane Emissions per well, direct measurement, tpy | | | 12.4[c] | 6.39 |

[a] API/ANGA do not separate emissions for plunger lifts from emissions from vented wells.
[b] Total estimated emissions divided by number of wells.
[c] Different wells than those for which engineering estimates provided. The GHGI does not specify which wells were directly measured.
[d] Data derived from Liquids Unloading Whitepaper Table 2-2
[e] Data derived from Liquids Unloading Whitepaper Table 2-4; emission factors estimates for plunger lift and venting wells are weighted averages of the emission factors given for the six regions.

Although these estimates differ at the margins, they reveal general trends:

- Total methane emissions from unloading exceed 300,000 tpy. The 2014 Inventory, which had the lowest estimate of total emissions, concluded that, as summarized by the white paper, "liquids unloading emissions in 2012 were 14% of overall methane emissions from the natural gas production segment."
- Roughly 60,000 wells have unloading emissions annually.
- Approximately half of these wells use plunger lifts and the other half vent.
- Average methane emissions for wells that emit are roughly 5 tpy.
- Average emissions for wells that emit despite using plunger lifts are higher than average emission from wells that unload using blowdowns. This does not suggest that plunger

[116] API/ANGA estimate that 174,743 wells have plunger lifts, API/ANGA at 13, but that only 36,806 wells of these wells have emissions associated with unloading, id. at 14.
[117] *See* footnote "b," Liquids Unloading White Paper, Table 2-4. The GHGI incorporates region specific emission factors; differences between GHGI and API/ANGA activity factors for each region lead to different nationwide averages for activity factors here.

> lifts fail to reduce emissions: operators are more likely to have voluntarily installed plunger lifts on high-producing and high-emitting wells where uncontrolled emissions would be much higher than the average emission with plunger lifts installed reported here.

Several of the marginal differences in these estimates are to be expected. As we have explained elsewhere, the GHGRP data should, as it does, include fewer wells than the 2014 Inventory, given that the GHGRP only collects data from large sources.

While the API/ANGA, 2014 Inventory, and GHGRP data are in broad agreement, there are many reasons why all three data sets are likely to be conservative. First, the API/ANGA, 2014 Inventory, and (to a large extent) GHGRP emission factor estimates rely largely on engineering calculations, but it is notable that the GHGRP data derived from direct measurements is higher than that derived from engineering calculations.

Second, the survey data underlying emission factor estimates in the API/ANGA and 2014 Inventory is markedly lower than data underlying EPA's previous estimates, and EPA has not explained why the data underlying these former estimates is no longer relevant. Although the API/ANGA study's activity factor estimates are based on a survey of nearly 60,000 wells covering 18 basins, the study's emission factor estimates rest on data from 5,327 wells that vent during unloading, from an unknown number of basins.[118] Prior to the API/ANGA study, EPA estimated emission factors for wells that vent during unloading on the basis of prior data from 2,219 venting wells (2,200 wells in the San Juan Basin and 19 wells in Big Piney, Wyoming) regarding frequency of blowdowns, or venting, and engineering calculations of emissions per blowdown.[119] Using these inputs, the 2011 Inventory estimated an emission factor of 27.2 tons per year per liquid unloading event—over five times the API/ANGA estimated emission factor.[120] Although San Juan and Big Piney data encompassed only half the number of wells used in the API/ANGA study, it appears that this data could be used in conjunction with data from the 5,327 wells in the API/ANGA study. EPA should also request that API/ANGA provide location data for the 5,327 wells used to determine the emissions factor in the API/ANGA study, so that any geographic differences may be analyzed.

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[118] API and ANGA, *Characterizing Pivotal Sources of Methane Emissions from Unconventional Natural Gas Production, Summary and Analysis of API and ANGA Survey Responses, Final Report*, (Updated Sept. 21, 2012), Table 6, page 14, Liquids Unloading Emission Estimation Based on Survey Data. 5,327 wells is the sum of the well counts for plunger-equipped wells that vent and non-plunger-equipped wells that vent. This total number of wells is also found by totaling the well counts listed in Tables C-1 through C-4 in Appendix C of the report. API and ANGA previously released a "Final Version" of this report which only listed 5,276 wells in Tables C-1 through C-4. Some entries in the tables in the previous version were removed in the later version; other entries absent in the earlier version appeared for the first time in the later version. No explanation is given for the changes in the data between the two versions.

[119] EPA, Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry: Background Technical Support Document (Nov. 2010), pp. 89-90, *available at* http://www.epa.gov/climate/ghgreporting/documents/pdf/2010/Subpart-W_TSD.pdf. EPA's previous estimate was based on reports of emissions from 2,200 wells in the San Juan Basin and 19 wells in Big Piney (Wyoming).

[120] This represents the weighted average of "Well Clean Ups (LP Gas Wells)" data from each reporting region. *See* EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (1990-2009), (Apr. 15, 2011), Annex 3, pages A-149 to A-153.

Third, the API/ANGA data may reflect reporting bias and not be representative of all U.S. gas well emissions. There is not sufficient information in the survey to confirm that data selected by 2012 API/ANGA members for calculation of the emission factor estimate provides an accurate representation for liquids unloading emissions across the United States for all wells that have unloading emissions. The API/ANGA estimates are based on data volunteered by API/ANGA members. Little information was made publicly available about the survey methods, which companies reported data, or whether the data is representative of nationwide emissions. Accordingly, estimates derived from this self-reported data are likely biased towards lower emissions and thus conservative.

Finally, the API/ANGA data makes it very clear that liquids unloading emissions can be extremely high in some basins. Since liquids unloading emits raw gas, which is often rich in VOC and has significant amounts of HAP, this can affect air quality in regions with dense gas production. For example, one respondent to the API/ANGA survey reported emissions in the Rocky Mountain region of over 6 million cubic feet of gas *per well* in 2011. Using EPA's standard ratios of VOC and HAP to methane for raw gas, this suggests that VOC and HAP emissions were 18.5 tons of VOC and 1.34 tons of HAP per well per year. Given the high concentration of wells in some areas (and the tendency for wells for a single operator to be geographically grouped for logistical purposes), this suggests that emissions can be very high in some regions. In the extreme case in the API data, a single operator reported emissions of over 187 million cubic feet of gas in a single year in the Midcontinent region, which implies 568 tons of VOC and 41 tons of HAP.[121]

### B. Available Control Technologies

Plunger lifts avoid venting by removing liquid from the well before liquid loads reach levels that "kill" the well and halt gas production. If a plunger lift is not operated optimally, however, liquid sufficient to kill the well can eventually accumulate despite the presence of the plunger lift, and in these cases, the well can be vented for a short period of time to generate the differential pressure needed to resume well liquid removal.

These intermittent periods of venting can be avoided by optimizing operation of the plunger lift, typically with an automated controller. Automated controllers also enhance plunger lift performance by monitoring wellhead parameters such as tubing and casing pressure, sales line pressure, flow rate, and plunger travel time to minimize manual well venting when the plunger lift is overloaded. Automated controllers can be made "smart" to monitor and better time automation, producing further emission reductions and increases in well production.

There are numerous other artificial lift methods that are also common, easy to install and operate, and can achieve high methane abatement efficiencies. These methods include: installation of smaller diameter tubing (velocity string), use of compression, foam, hydraulic pumps, beam pumps, gas lift, electric submersible pumps, progressive cavity pumps, among other methods.[122]

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[121] Calculations based on data listed in API/ANGA data tables. See *Petition for Reconsideration submitted by Peter Zalzal, Attorney, Environmental Defense Fund on behalf of the Clean Air Council, et al. regarding Oil and Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews*, at 5-6, *available at* http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-4575.
[122] *Id.*

The white paper omits discussion of several of these methods of liquids unloading, notably gas lift. Gas lift re-injects produced gas to reduce bottom-hole pressure and increase gas production rate to lift liquids. Gas lift has several advantages over other lift methods, including that it can be used in highly deviated wells.[123] Gas lift has primarily been used in offshore wells, but is growing in popularity for onshore applications. EPA should consider gas lifts as one of many viable liquid removal technologies.

Finally, we note that, if venting during liquids unloading cannot be eliminated using plunger lifts with smart automation (see below), EPA should consider requiring operators to capture or, as a last resort, flare gas that would otherwise be vented. When liquids are being brought to the surface they must be handled in tanks and there are means, such as vapor recovery units, to capture gas that would otherwise be vented from tanks during loading operations.

Several liquids unloading technologies are already prevalent. According to API/ANGA, over 75 percent of wells that unload are able to do so with no unloading emissions:

**Table 17: *API/ANGA Estimates of Unloading Utilization***[124]

| | # of Wells | % (of all wells that unload) |
|---|---|---|
| Wells with plunger lifts and no emissions | 137,937 | 51.4 |
| Wells with other artificial lifts and no emissions | 65,003 | 24.2 |
| Wells with plunger lifts that have unloading emissions | 36,806 | 13.7 |
| Wells that blowdown/vent to unload | 28,863 | 10.7 |

Thus, according to API/ANGA data, available technology allows liquids unloading without any emissions from venting the well. Wells that unload using blowdowns can apply these technologies to significantly reduce, if not eliminate, their emissions. Moreover, many wells that currently emit despite using plunger lifts may lack smart automated controllers or other optimizations that would further reduce emissions; adding smart controllers to wells that lack them is likely to significantly reduce emissions.

### C. Abatement of Emissions from Wells Currently Unloading with Blowdowns

The most common, effective control option for wells currently unloading using blowdowns is installation of plunger lifts with smart automation.

Capital costs for a relatively routine plunger lift installation can range from $1,900 to $10,400 per well. Costs at the upper end include some amount of remediation for wells, though some wells will require higher investment.[125] Smart automation can increase the total installation cost to $7,600 to $28,000 per well.[126] Annualizing the capital cost over 5 years at 7%, and including

[123] *See, e.g.* Lea, J. F., Nickens, H. V., & Wells, M., *Gas well deliquification* (2011), Gulf Professional Publishing.; Lea, J.F, and Dunham, C.L. *Artificial Lift Advances Address Challenges, Trends In Gas Well Deliquification*, The American Oil & Gas Reporter (2009).
[124] 2012 API/ANGA Survey, p. 13-14.
[125] Lessons Learned – Plunger Lifts at 3-4.
[126] Additional costs for smart automation are from Lessons Learned – Fluid Options, Exhibit 9.

annual maintenance costs of $700 to $1,300 per well,[127] produces a total annualized cost per plunger lift of $1,300 to $3,800 per well per year. The yearly cost for a lift with smart automation (same equipment lifetime and maintenance costs) would range from $2,600 to $8,200 per well.

Natural Gas Star partners have reported that plunger lifts decrease gas venting by an average of 600 Mcf per year per well.[128] This translates to a methane abatement cost of between $91 and $300 per short ton of methane, not including the added revenue from selling gas not vented. For plunger lifts with smart automation, reported abatement ranges from 800 to 1,460 Mcf per year per well,[129] for abatement costs of between $92 and $540 per short ton, again neglecting the revenue from selling the gas instead of venting it.

If revenue from additional gas sales is included, plunger lifts with or without smart automation quickly become profitable, though the former is much more so. The gas captured through emissions abatement provides some revenue—including the value of this gas, at $4 per Mcf, plunger lifts alone have net abatement costs of -$96 to $110 per short ton of methane, and plunger lifts with smart automation have net abatement costs of -$120 to $330 per short ton of methane. Far greater revenues are realized by increased well production and prolonged well life.

Increased production can be substantial (hundreds of Mcf per day for some wells), but will vary between wells based on well production and age.[130] Furthermore, plunger lifts can reduce maintenance and labor costs by reducing the need for well maintenance (such as blowing liquids out of the well manually, but also down-hole work to repair damage to wells from the effects of long-term liquids build-up). These savings can easily exceed $10,000 per well per year.[131] The combination of these savings and the increased revenue from increased production can make the economic benefits of plunger lift installation very significant.[132]

Thus, it is likely that most, if not all, unloading emissions from wells using blowdowns could be abated using plunger lifts or other artificial lift methods. Using a conservative assumption of only 90% control and the 2014 Inventory data, the total abatement potential is 154,451 tpy of methane.

### D. Abatement from Wells Already Using Plunger Lifts

For wells that already have plunger lifts installed but that still have emissions, emissions can often be reduced by subsequent installation of smart automation. As explained above, smart automation provides significant emission reduction beyond use of plunger lifts that are manually operated or simply timed to operate on a fixed period. The API/ANGA data indicates that 79% of wells using plunger lifts are able to do so without any liquids unloading emissions. If this is correct, it is likely that many of the remaining wells could reduce or eliminate their emissions by installing smart automation or similar optimization.

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[127] Lessons Learned – Plunger Lifts at 4

[128] *Id.*at 1.

[129] Lessons Learned – Fluid Options at 1.

[130] Lessons Learned – Plunger Lifts.

[131] *See*, *e.g.*, *id.* at 9.

[132] *See, e.g.*, Marathon Oil Company and the Independent Petroleum Association of Mountain States, *Plunger Lifts and Smart Automation, EPA Natural Gas STAR, Producers Technology Transfer Workshop* (2008), available at http://www.epa.gov/gasstar/documents/workshops/2008-tech-transfer/denver3.pdf.

The Natural Gas STAR data summarized above indicate that adding smart automation provides an additional 200 to 860 Mcf per well per year of methane abatement beyond the average abatement from use of plunger lifts alone.[133] 200 Mcf, the bottom of this range, is equivalent to 4.16 tpy. This reinforces API/ANGA's indication that optimized plunger lifts can completely eliminate emissions, as the 200 to 860 Mcf abatement potential encompasses much of the range of estimated emissions for wells with plunger lifts. More conservatively, other industry data indicates that smart automation can halve emissions from a well with a plunger lift. BP showed that 50% reductions could be achieved on approximately 2,200 wells.[134]

Natural Gas Star partners estimate that the cost of adding smart automation is between $5,700 and $17,600.[135] In an industry report specifically looking at the benefits of adding smart automation to wells, Marathon estimated the cost of a smart automatic controller at $11,000: $5,000 for the automatic controller and $6,000 for the cost of installing the smart controller upgrade.[136] Using this figure and annualizing over ten years at a 7% interest rate, this suggests that smart automation can reduce emissions from wells with plunger lifts that still vent at an abatement cost of at most $380 per ton of methane.

We note that the data surveyed in the white paper does not indicate what fraction (if any) of wells that emit despite using plunger lifts already have smart automated controllers installed. Thus, it is difficult to estimate the total methane abatement that could be achieved by installing smart automated controllers on wells that lack them. If none of these wells have smart automated controllers, a 50% reduction in liquids unloading emissions from these wells represents a 65,573 to greater than 66,117 tpy reduction, using 2014 Inventory and GHGRP data, respectively.[137] If we instead use the 4.16 tpy abatement figure indicated by Natural Gas STAR data, and the counts of 23,503 to 36,806 wells with plunger lifts with emissions (2014 Inventory and API/ANGA, respectively), this provides an abatement potential of 97,772 to 153,112 short tons of methane per year.

### E. Responses to Charge Questions

- **Question 1:** Above, we have provided comments and critique of the data sources for liquids unloading discussed in the white paper.

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[133] Lessons Learned – Fluid Options at 1.

[134] Pure Automation, Inc., *Smart Automation of Plunger Lift Systems, Exploring the Benefits of Plunger Automation and Advanced Optimization Technologies* (2010). *See also* Methane to Markets, Reduced Emission Completions/Plunger Lift and Smart Automation, Oil & Gas Subcommittee Technology Transfer Workshop, January 2009.

[135] Lessons Learned – Plunger Lifts and Lessons Learned – Fluid Options. These values are the differences in minimum and maximum prices between plunger lift installation with and without smart automation.

[136] Marathon Oil Company and the Independent Petroleum Association of Mountain States, *supra* n.136.

[137] The GHGRP figure is conservative in that it uses the emission factor derived from engineering estimates, ignoring the higher average emissions reported in the GHGRP from wells that directly measured emissions. The API/ANGA data does not lend itself to a 50% reduction estimate because API/ANGA provided neither an emission factor nor a total emission estimate for plunger lift wells with methane emissions.

- **Question 4:** As noted above, the white paper did not discuss the use of gas lift to remove liquids from wells.

- **Questions 11 and 12:** We have raised this issue above. If venting emissions from liquids unloading cannot be eliminated with plunger lifts (including smart automation) and the other technologies discussed here, EPA must consider requiring "end of pipe" controls to prevent emissions of methane. Given the availability of VRUs to capture emissions from working and flash losses from tanks and direct this gas, that would otherwise be vented or flared, EPA should consider whether VRUs could be used to effectively capture emissions that would otherwise be vented. If that is somehow infeasible, EPA should consider whether flaring is appropriate for liquids unloading emissions.

## VI. Leaks

Leaks (i.e., unintentional emissions) from static components at oil and natural gas facilities, such as tanks, hatches, meters, flanges, valves, connectors, regulators, etc., emitted over 2.4 million short tons of methane in 2012, according to EPA's nationwide estimates in the 2014 U.S. Greenhouse Gas Inventory (2014 Inventory). We include here leaks from wellpads (natural gas and petroleum), gathering compressor stations, processing plants, transmission compressor stations, and aboveground centralized facilities in the natural gas distribution sector, as all of these facilities can leak methane excessively and the mitigation approach described below is appropriate for all of these facilities.[138] As evidenced by independent research described below, these figures clearly underestimate leaks from U.S. oil and gas facilities by a significant margin.

Cost analyses, some of which are described in the EPA's White Paper, *Oil and Natural Gas Sector Leaks,* clearly show that substantial mitigation of methane emissions from leaking components is achievable at reasonable costs to producers through mandatory leak detection and repair (LDAR) programs. However, it is notable that these analyses used estimates of leaks from these facilities that are consistent with the 2014 Inventory and the information used to create that document. It is notable that the costs for LDAR programs these analyses present are reasonable despite the fact that, as described below, there is abundant evidence that leak emissions actually are significantly higher than reported in the 2014 Inventory. Since the emissions abated by LDAR programs will be higher than calculated, based on the 2014 inventory, the actual abatement costs will clearly be lower than the costs derived from these analyses. One important exception (Carbon Limits, 2013) directly assessed costs associated with LDAR programs independent of any general estimate of facility leak rates. The Carbon Limits analysis was designed in a very conservative yet robust manner, as described below, yet still supports the fact that LDAR programs can be implemented at reasonable costs.

As shown below, LDAR programs reduce emissions at very reasonable costs. As described below, the Carbon Limits analysis shows that monthly LDAR programs costs $1,180 per ton of methane abated at compressor stations and $840 per ton at well facilities. Colorado's estimates of the overall costs of their "tiered" program, where facilities with smaller potential leak emissions

[138] This figures, and figures below on abatement of leaks, include emissions listed as "Fugitives" in the USGHGI, in addition to leaks from static components on compressors, which the USGHGI does not separate from venting of leaks through seals on compressor shafts and rods. Venting of leaks from seals on shafts and rods is discussed in the Compressors White Paper.

have less frequent LDAR surveys, are less, and data submitted by industry suggests real costs are lower yet.

Given the harm caused by excessive methane emissions, and the availability of LDAR programs at a reasonable cost, EPA must address methane emissions from leaks and require facility operators to regularly conduct instrument-based leak detection surveys and repair the leaks that are identified.

Our comments for the leaks white paper are structured as follows.

In Section A, we describe critical synthetic conclusions from reports described in the white paper – and reports that it does *not* describe – that inform key questions on emissions and costs of abatement addressed by the white paper. These conclusions are: 1) a large body of published research shows that not only are methane emissions from oil and gas are higher than reported in the 2014 Inventory, but analysis of the nature of natural gas emissions strongly suggests that leaks are important contributors to additional methane emissions that are not included in the inventory's estimates; and 2) that LDAR program costs are very reasonable.

In Section B, we provide specific comments, clarifications, and corrections for the leaks white paper.

In Section C, we provide answers to some of the Charge Questions for Reviewers.

## A. Critical Synthetic Conclusions

### i. Methane Emissions from Oil and Gas are Underestimated by the 2014 Inventory, and Available Evidence Implicates Leaks

As discussed in part II.B above, a number of top-down studies have been published since 2000. A study by Brandt *et al.*, published this past winter in *Science* reviewed over a dozen of these studies. Brandt *et al*. conclude that "measurements at all scales show that official inventories consistently underestimate actual [methane] emissions, with the [natural gas] and oil sectors as important contributors."[139] The inventories' underestimate is substantial. Brandt *et al.* estimate that the 2013 Inventory[140] underestimates methane emissions from <u>all</u> U.S. sources by 25 – 75%, and show that oil and natural gas systems must account for much of this underestimate. Brandt's central estimate for the methane emissions not reported in the 2013 Inventory, 14 Tg per year,[141] is almost twice as large as the 2014 Inventory figure for all methane emissions from both oil production and natural gas systems, 7.7 Tg/y. While it is certainly possible that other sectors aside from oil production and natural gas systems also emit more methane then the Inventory reports, it is certain (due to measurements in oil and gas producing regions, and isotopic and chemical analysis of the observed methane and other hydrocarbons present in the air) that oil and gas

139 A.R. Brandt *et al*., (2014) "Methane Leaks from North American Natural Gas Systems," *Science,* 343, 733, *available at* http://www.novim.org/images/pdf/ScienceMethane.02.14.14.pdf.
140 Brandt *et al*. used the 2013 Inventory, the latest version of the Inventory available in final form at the time their analysis was performed, as the basis of their comparison. The 2014 Inventory *reduced* EPA's estimate of emissions from natural gas systems, so the underestimation of methane emissions documented by Brandt *et al.* has actually become slightly more severe.
141 See Brandt *et al.*, (2014), at figure 2.

systems contribute significantly to these unaccounted-for methane emissions. For example, a study published since the Brandt *et al*. review was completed reported that 2012 methane emissions from oil and gas operations in Colorado's Denver-Julesberg basin were almost three times higher than predicted by the 2014 Inventory.[142]

It is very likely that leaks account for a significant portion of the excess methane emissions from oil and gas facilities. As noted by Brandt *et al*., analysis of individual leak measurements from oil and gas facilities consistently shows skewed distributions with a very small numbers of sources having highly disproportionate emissions, thus accounting for a large percentage of total emissions. For example, the Clearstone II study referenced in the white paper found that 58% of the identified fugitive emissions from over 75,000 components at five gas plants was emitted by a total of just 50 leaks and compressor seals.[143] It is very likely that studies such as the GRI/EPA (1996) study have sample sizes too small to sufficiently represent the emissions from these high emitters.[144] Furthermore, the Correlation Approach used by the GRI/EPA study will often be inaccurate for very high emitters because Method 21 screening instruments will be unable to measure the levels beyond a certain value (*i.e.*, "peg," a term used because the needle on an analog meter would hit a peg on the top of the scale). If that occurs, the default values for emissions correlating with pegged screening values will be inaccurate and thus the GRI/EPA study likely underestimates these emissions.

## B. Costs for LDAR Programs are Very Reasonable

The leaks white paper does not adequately describe some of the recent analysis of the costs associated with abating emissions of methane and other air pollutants with LDAR programs.

While the leaks white paper does describe the study by Carbon Limits, "Quantifying Cost-Effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras,"[145] important aspects of the study design and results were not described.

The Carbon Limits study was conducted using a database of detected leak sizes and repair costs from surveys conducted by two firms that provide LDAR survey services to the oil and gas sector. It is important to note that *these surveys were predominantly repeat surveys*. The facilities had been subject to rules (in Canada) requiring LDAR survey for some years. The rules allow use of OGI, and in general operators use OGI for surveys. As a result, the leak rates found during the survey were lower than would be found during surveys of most facilities in the U.S. where LDAR programs have either not been required under state or federal rules[146] or implemented voluntarily. Accordingly, the volume of methane emissions abatement calculated from these surveys is less than it would be in an area without LDAR programs in place. As such, the costs per ton of

[142] G. Pétron *et al*., (2014) "A new look at methane and non-methane hydrocarbon emissions from oil and natural gas operations in the Colorado Denver-Julesburg Basin," *J. Geophys. Res. Atmos.* 119, *doi:*10.1002/2013JD021272.
[143] See Clearstone II study, Table 2.
[144] Brandt et al. (2014).
[145] The leaks white paper cites a pre-publication version of the Carbon Limits study that was posted online in late 2013. The Carbon Limits study has since been finalized and is available at http://www.carbonlimits.no/PDF/Carbon_Limits_LDAR.pdf
[146] With the exception of gas processing plants, where NSPS Subparts KKK and OOOO do require LDAR for facilities installed after 1984.

pollution mitigation presented by the Carbon Limits report are overestimates of the true cost per ton of avoided pollution from LDAR programs more generally speaking.

Nevertheless, the costs presented in the report are still very low. For less-frequent surveys, the value of conserved gas is larger than the cost of the surveys and repairs, so the abatement cost is negative (meaning the facility owner earns more money from increased sales than it spends). For more frequent surveys, which are appropriate for larger facilities and justified to prevent emissions, costs are positive but still very reasonable.

**Table 18:** Emissions net abatement cost ($ / metric ton) of LDAR programs

| Facility Type | Survey Frequency | | | |
|---|---|---|---|---|
| | Annual | Semi-annual | Quarterly | Monthly |
| ***Cost of Leak Detection and Repair per tonne of VOC abatement*** | | | | |
| Gas plant | -256 | -108 | 187 | 1,365 |
| Compressor station | -287 | 45 | 708 | 3,357 |
| Well site & well battery | -429 | -148 | 412 | 2,647 |
| ***Cost of Leak Detection and Repair per tonne of CO2e abatement*** | | | | |
| Gas plant | -6.3 | -2.7 | 4.6 | 34 |
| Compressor station | -4.5 | 0.71 | 11 | 52 |
| Well site & well battery | -5.9 | -2.0 | 5.7 | 37 |

The leaks white paper also omits several relevant analyses of the cost-effectiveness of LDAR programs that were entered into the record during deliberations over Colorado's new regulations on emissions of methane and volatile organic compounds (VOC) from oil and natural gas facilities. The Colorado Department of Public Health and Environment (CDPHE) estimated that the rule, which requires LDAR at frequencies determined by the potential emissions from a facility, would have a cost for compressor stations of $474 per short ton of methane and ethane emissions abatement and $994 per short ton of VOC emissions abatement.[147] Estimated costs for tiered LDAR at wellpads are $805 per short ton of methane and ethane emissions abatement and $1259 per short ton of VOC emissions abatement.[148] CDPHE also provided data on the costs of inspections and repairs that are quite similar to the cost data reported by Carbon Limits.[149] Additionally, CDPHE found that repair costs are less than the value of the gas that is conserved by the repairs, consistent with the results of the Carbon Limits study.[150]

Several oil and gas producers supported Colorado's rule,[151] submitting data based on their own experience performing LDAR surveys during the rulemaking process. These data demonstrate

[147] Cost-Benefit Analysis, Submitted Per § 24-4-103(2.5), C.R.S. Table 33 (hereafter "Colorado Cost-Benefit Analysis"). Available at: ftp://ft.dphe.state.co.us/apc/AQCC/COST%20BENEFIT%20ANALYSIS%20&%20EXHIBITS/CDPHE%20Cost-Benefit%20Analysis_Final.pdf
[148] *Id*, table 35.
[149] *Id*, pages 17-27.
[150] *Id*, pages 21-22.
[151] Finley, Bruce. "Colorado pitches new rules to cut oil and gas industry air pollution," The Denver Post, 11/18/2013. (available at: http://www.denverpost.com/environment/ci_24548337/proposed-colorado-air-pollution-regs-clamp-down-oil).

that firms are able to perform LDAR surveys for even lower costs than were reported in the Carbon Limits study.

| Facility Type | Cost per Inspection | | |
| --- | --- | --- | --- |
| | Carbon Limits | Anadarko Petroleum Corporation[152] | Noble Energy Incorporated[153] |
| Compressor Station | $2,300 | $1,250 – $5,150 | |
| Multi well batteries | $1,200 | $450 - $800 | $263 - $431 |
| Single well batteries | $600 | | |
| Well site | $400 | | |

## C. Charge Questions for Reviewers

- **Question 1.** We have addressed this question above in Part VI.B with specific comments on the white paper.

- **Question 2.** As the white paper describes, emissions estimates for the GRI/EPA study, which is the basis for most of the emissions information in the inventories, were made using the Correlation Approach. Furthermore, the correlation equations used were derived from measurements carried out at facilities such as refineries, processing plants, and oil and gas production facilities. It is not clear that these correlation equations are appropriate for natural gas facilities that may operate at different temperatures and pressures, and that handle fluids of different properties (such as viscosity) than oil refineries.

  Modern leak quantification techniques, such as the Hi-Flow sampler used in the Carbon Limits study, Allen *et al.*, and the Fort Worth AQ Study, offer a far more direct quantification of leak emissions and should be used to estimate emissions whenever possible.

  As noted in section one of these comments, it is disappointing that the leaks white paper fails to describe or acknowledge the large body of work that demonstrates that methane emissions from oil and gas facilities are substantially higher than estimated in the 2014 Inventory and indicates that leaks compose a significant fraction of those additional emissions.

- **Question 3.** The *direct* emissions quantification methods described in this paper, such as using a Hi-Flow sampler, can be used at oil and gas production facilities, as well as at gas gathering, processing, and transmission facilities. In addition, they can also be used at aboveground natural gas distribution facilities, such as city gates, metering and regulating stations. It is disappointing that EPA has, without explanation, not discussed the substantial leaks from those facilities in this white paper. Such emissions amount to

[152] ftp://ft.dphe.state.co.us/apc/aqcc/PRESENTATIONS/Noble%20Energy%20Inc%20&%20Anadarko%20Petroleum%20Corporation/Anadarko.pdf
[153] ftp://ft.dphe.state.co.us/apc/aqcc/PRESENTATIONS/Noble%20Energy%20Inc%20&%20Anadarko%20Petroleum%20Corporation/Noble.pdf

420,000 tons of methane per year, according to the 2014 Inventory, not including leaks from underground pipelines or customer meters.

As we have noted above, the indirect Correlation Approach may be less applicable at some facilities, particularly if correlation equations were derived with data from facilities handling different fluids under different conditions. Direct measurements are preferred.

From conversations with representatives from industry, with LDAR service firms, and from public discussion during the process to develop and consider the recently passed oil and gas regulations in Colorado, it is very clear that the OGI method is the dominant methodology in use by industry today, and is used successfully at a wide range of facilities, as has been documented by GasSTAR.

- **Question 4.** As concern has risen over the identified harm to air quality from emissions from oil and gas facilities, particularly in the western U.S., researchers have responded with a range of measurements and studies of emissions from this sector. As described above in Part VI.A, these studies have consistently indicated that emissions are higher than reported in the inventories, and therefore that the damage from these emissions to climate and air quality is more substantial than indicated by the inventories.

  Numerous studies that will improve our understanding of emissions of VOC and methane from oil and gas facilities are currently underway or planned. However, it is critical to note that **the record establishes that even based solely on estimates from the 2014 Inventory, substantial emissions from leaks can be mitigated at reasonable costs using LDAR surveys**. It is challenging to quantify precise emissions from this sector, but it is abundantly clear that they are excessively large and can be reduced affordably. **EPA must not delay measures to reduce emissions on the basis of continued efforts to study emissions.**

  We are aware of a number of studies underway or planned to quantify emissions. For example, studies are underway across the industry to quantify emissions from particular facility types or components/processes, such as the studies of wellpad emissions, processing plants and gathering facilities that are coordinated by Environmental Defense Fund. The University of Wyoming is currently deploying the OTM 33A methodology developed by EPA, described in section 2.9 of the white paper, to measure emissions from significant numbers of wellpads to understand the distribution of their emission rates. And, the University of Colorado and partners are planning extensive measurements in the Denver/Julesberg basin this summer.

  These studies will improve the understanding of emissions from oil and gas operations, but will not perfect it. Given the clear data indicating that leak emissions are substantial and can be controlled at a very reasonable cost, EPA must move forward now to address the excessive emissions from leaks.

- **Question 5.** The predominant reason the emissions vary widely from facility to facility is the variability in the management approach of the facility operators. As discussed above in section one, super-emitters are a critical source of excess emissions.

Consider this data presented in and calculated from the Clearstone II study of emissions from gas processing plants:

| Plant | Component count for plant | Fugitive Emissions (Mcf/day) | Value of Leaking Gas* | Leaks from top 10 leaks (Mcf/day) | Fraction of leaks from top 10 leaks | Leaks / plant throughput (%) | Component leak frequency (%) |
|---|---|---|---|---|---|---|---|
| 1 | 22290 | 271 | $757,000 | 78 | 29% | 0.05 | |
| 2 | 12330 | 23 | $75,600 | 13 | 57% | 0.01 | 0.74 |
| 3 | 18353 | 117 | $613,000 | 53 | 45% | 0.09 | |
| 4 | 16687 | 69 | $194,000 | 60 | 87% | 0.15 | 1.34 |
| 5 | 4778 | **423** | **$1,297,000** | **317** | 75% | **0.48** | **9.31** |

*Based on the price of gas at time of the surveys ($7.15/MCF).

The very high emissions from Plant 5 illustrate that some facility operators choose not to properly address leaks at their facilities, despite the substantial value of product that they lose by neglecting to do so. Plant 5 did handle sour gas, which creates more corrosive conditions, but so did Plant 4, which had a leak rate less than one-third of Plant 5 and a leak frequency (fraction of components leaking) about seven times lower than Plant 5.

Other factors certainly contribute to the leak rate of these facilities. As operations get more complex (for example, handling oil and gas as opposed to simply dry gas), component counts increase and leaks may therefore increase. Nevertheless, the overriding factor is clearly the attention of operators to reduce leaks.

- **Question 6.** This paper identified all technologies we know of in use *operationally* in the oil and gas sector to identify leaks. As noted above, OGI is currently the dominant method to identify leaks, and has been shown to be affordable and very effective.

- **Question 7.** As mentioned above, OGI is currently the dominant method to identify leaks, and has been shown to be affordable and very effective. OGI identifies over 90% of the leaks that can be identified using Method 21 techniques such as the TVA, for example.[154] CDPHE found that the costs of using OGI to survey a facility for leaks are roughly half of the costs of using Method 21,[155] while Clearstone II found that OGI screening is about three times faster than Method 21, as noted in the leaks white paper. Finally, OGI has advantages in the screening of components that are challenging to access, and for screening surfaces, such as pipe runs and tanks, for corrosion leaks.

- **Question 8.** As noted above, OGI is currently the dominant method to identify leaks, to our knowledge, across segments of the natural gas industry. One exception is in distribution, where the vehicle-based sensors discussed in section 3.1.4 are in use for

[154] Based on Clean Air Task Force and Environmental Defense Fund analysis of data from the Ft. Worth AQ Study.
[155] Colorado Cost-Benefit Analysis at 20.

monitoring and LDAR, but this is focused on detecting leaks from underground pipelines. We are not aware of routine use of other methods, with the exception of Method 21 approaches where required (newer gas processing plants, principally).

- **Question 9.** Industry is currently performing LDAR surveys in some geographic areas at frequencies ranging from annual to monthly. Annual surveys are performed at wells under Alberta regulations, and at new or modified well facilities in Pennsylvania and parts of Wyoming, for example. Some companies have instituted annual LDAR with OGI as a voluntary measure. To achieve greater emissions reductions, LDAR is performed as frequently as monthly by some firms in Wyoming.[156]

  Given the damage caused by air emissions from oil and gas facilities, annual LDAR will be too infrequent for many facilities. We support the tiered approach taken in the recent Colorado regulations, where the frequency of instrumental LDAR was based on the potential leak emissions from the site. However, the Colorado regulations allow smaller well production sites to only perform LDAR a single time. Any leaks that arise after the single LDAR survey will not be found under the regulation and may continue indefinitely. Given the large emissions possible from single super-emitters, and the very large number of small facilities, this exemption from regular LDAR for small facilities is not appropriate.

- **Question 10.** Ambient / mobile monitoring is an exciting technology that may enable far more frequent monitoring of oil and gas facilities for leaks at reasonable cost. However, the methodologies for these technologies as research techniques in the field are still being worked out. Efficacy varies with weather (especially wind), site layout, and context. It is not clear how they could be deployed in some locations, such as very hilly or wooded areas, or sites near buildings. Furthermore, it is not at all clear how compliance with an LDAR survey requirement using ambient / mobile monitoring could be assured. There would be many ways to avoid identifying actual leaks using these methods.

- **Question 11.** The Carbon Limits study was able to directly compare the costs of repairing leaks to the value of the gas conserved by doing so, using real data from thousands of surveys, finding that the net present value of repairing the leak is almost always positive. CDPHE made a similar finding using a different methodology and data. LDAR survey cost is low but the Carbon Limits study, and other data, suggest that when LDAR is performed at reasonable frequencies (quarterly or monthly), the total LDAR program does have positive, but reasonable, costs.

- **Question 12.** The most critical goal of LDAR programs must be to reduce emissions from leaks, rather than quantifying them. We believe that it is not necessary under the NSPS program to require that the size of leaks be quantified (in concentration or volume), since it will often be faster and far simpler to simply fix them. Records should be kept of the existence of leaks, so that regulators can verify compliance and so that facility operators can identify equipment that is leaking repeatedly to address root causes.

[156] For example, Encana monitors 170 well production facilities in Wyoming's Jonah field monthly with OGI. *See* ftp://ft.dphe.state.co.us/apc/aqcc/PRESENTATIONS/Encana%20Oil%20&%20Gas%20USA%20%28Encana%29/Encana%20REB%20Presentation.pdf.

However, operators that repair leaks immediately or within a period of a few days should not be required to quantify leaks.

Any leaks that are not repaired within a few days must be measured to ensure that damage from the ongoing leak is quantified, and so that regulators can consider those emissions when evaluating any request for an exemption from repair requirements due to claims of infeasibility, etc.

- **13.** We believe that LDAR technology will advance substantially in the future and are aware of public and private efforts to promote this development. This is exciting since new technology may enable far more frequent, and even continuous, monitoring of oil and gas facilities for leaks at reasonable cost. Regulations / Regulators should ensure that new technologies can be adopted to improve environmental performance once they are demonstrated. Even under very optimistic assumptions, use of these more advanced methods and technologies is several years away, and given the proven, low-cost performance of technologies such as OGI, EPA must not delay addressing leaks from oil and gas facilities in anticipation of some future technology.

## VI. Oil Wells

### A. Oil Wells Produce Gas, Which Can Be Managed by Capture or Combustion

Oil wells produce oil, natural gas, and formation water. The amount of gas that is produced along with the oil is a function of the reservoir type and depth, hydrocarbon type, well age, and the pressure and temperature changes that occur as the oil and gas reach the surface processing equipment. Gas oil ratios will increase over time as wells age. As is true of natural gas generally, gas produced in association with oil wells is primarily methane, but includes VOCs and some other chemicals as well.

Oil reservoirs are classified according to fluid type (heavy oil, black oil, and volatile oil), with lighter oils having higher gas-oil ratios.[157] Dry gas wells do not produce associated liquids at the surface (although very few wells produce truly dry gas).

**Table 19: Associated Gas Volumes per SPE Handbook**

| | Initial Dissolved Gas Oil Ratio (scf/bbl) | |
|---|---|---|
| | Min | Max |

[157] Lake, L., Petroleum Engineering Handbook, Society of Petroleum Engineers, 2007, Volume V(B), Table 9.1, V-897.

| | | |
|---|---|---|
| Heavy Oil | 0 | 200 |
| Black Oil | 200 | 900 |
| Volatile Oil | 900 | 3,500 |
| Retrograde Gas Condensate | 3,500 | 30,000 |
| Wet Gas | 30,000 | 100,000 |

This gas is brought to the surface during all stages of production, including completion, recompletion, and operation of an oil well. For every stage, gas can be dealt with in one of three ways: it can be vented, combusted, or captured. Venting releases methane into the atmosphere, causing harmful pollution as well as creating potentially explosive vapor levels. To flare, gas is routed away from the well operations to a combustion device that burns the gas. Flaring destroys methane, VOC, and many other pollutants, and resolves the explosive vapor problem. Flaring also generates air, light, and noise pollution, and creates economic waste by combusting gas that could otherwise be collected and sold. Capture is therefore generally the most preferable option. Captured gas can be routed to a pipeline and marketed, used productively onsite, or re-injected into the formation.

While flaring is preferable to venting, EPA should take all available steps to limit both. Many other regulators have led the way, adopting regulations to limit both venting and flaring of gas associated with oil production. For example:

- Colorado Rule 912 prohibits unnecessary or excessive venting or flaring from a well. Flaring may be required if necessary to protect public health, safety and welfare.[158]

- Montana requires VOC vapors (including methane) greater than 500 British Thermal Units (BTUs) per cubic foot from wellhead equipment with the potential to emit 15 tons per year or greater, to be routed to a control device (such as a flare), or to a pipeline for sale.[159]

- Alaska requires operators to minimize amount of gas vented and flared to only that needed to handle an emergency, operational upset, or safety

[158] Colorado Oil and Gas Commission, Rule 912.

[159] Montana Administrative Rules § 17.8.1711.

situation, and requires the amounts of vented and flared gas to be tracked.[160]

- Internationally, the Global Gas Flaring Reduction Partnership found that "Many regulatory regimes (e.g., Alberta (Canada) and the United Kingdom) require each operator to make an economic evaluation of all the available associated gas utilization options, and to utilize the gas whenever gas utilization is shown to be economic. Only if all available options can be shown to be sufficiently uneconomic then the gas may be flared or, if unavoidable, vented. In Alberta (Canada), uneconomic means projects with Net Present Values less than minus 50,000 Canadian dollars."[161]

These regulators have demonstrated that emission of associated gas can be controlled, but most states do not have analogous regulations. Other states, such as North Dakota, have not taken sufficient action to address venting and flaring, with extensive emissions as a result. As the materials discussed in the white papers show, existing regulations have not solved the problem.

### B. Gas Emissions During Oil Well Completion

As summarized in the whitepaper, recent studies indicate significant emissions from oil well completion.

#### i. Oil Well Completion Emission Factor

**Table 20: Summary of Oil Well Completion Emissions (corrected)**

| Study | Average Uncontrolled Methane Emissions (short tons/completion) |
|---|---|
| ERG/ECR (7 day flowback) | 24 |
| ERG/ECR (3 day flowback) | 7.7 |

[160] Alaska Oil and Gas Conservation Commission, Alaska Administrative Code 20 AAC § 25.235(d).

[161] Global Gas Flaring Reduction Partnership, Guidance on Upstream Flaring and Venting Policy and Regulation, March 2009.

| | |
|---|---|
| EDF/Stratus Analysis of HDPI (Eagle Ford) | 27.2 |
| EDF/Stratus Analysis of HDPI (Wattenberg) | 10.5 |
| EDF/Stratus Analysis of HDPI (Bakken) | 19.8 |
| EDF/Stratus Analysis of HDPI (weighted average) | 17.3 |
| EDF analysis of GHGRP data | 24 |
| Allen | 213.3 |
| Brandt et al. (Eagle Ford) | 100.2 |
| Brandt et al. (Bakken) | 34.4 |
| Brandt et al. (Permian) | 34.3 |

This table corrects the one included on page 44 of the oil whitepaper, which listed metric ton values for Brandt et al. but short tons for the other studies.[162] We have also included the weighted average from the EDF/Stratus analysis and the estimate from the EDF analysis of GHG reporting program data.[163]

The values given by these studies are conservative in many regards.

The ERG/ECR authors identify three oddities in their data set, "The net effect of [which] is that the average daily gas production values may be skewed low."[164] An additional factor not identified by the authors is that the study uses a narrow definition of "oil wells," including only wells with a gas to oil ratio of less than 12,500 scf/barrel.[165] In general, wells with higher gas to oil ratios will have higher completion emissions. This is particularly pertinent here, because there may be many wells that are not "oil wells" for purposes of the ERG/ECR study but that also are not "gas wells" within the scope of the 2012 NSPS. The 2012 NSPS only regulates emissions from completion of "gas wells." Gas wells are defined as "onshore well[s]

[162] We further note that in discussing Brandt *et al.* on page 19, the whitepaper uses the incorrect conversion factor of 1 metric ton = 1.02311 short tons. The correct ratio is 1:1.102311. The short ton values in Table 3-7 are derived using this improper value. This appears to be a typographic error, however, as the whitepaper appears to have used the correct ratio elsewhere.
[163] Summarized in the EDF/Stratus analysis. EDF, Comments on "Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012," available at http://blogs.edf.org/energyexchange/files/2014/03/EDF-Comments-Draft-2014-GHG-Inventory_031014.pdf.
[164] A-5.
[165] A-3.

drilled principally for production of natural gas."[166] While we contend that the definition of a gas well should be interpreted broadly, we note that Texas, Alaska, and New Mexico (for example) use a gas to oil ratio of 100,000 scf/bbl as the dividing line between gas and oil wells.[167,168,169] Thus, there are many wells that are likely to have high completion emissions, that are excluded from the ERG/ECR study, but that might not be regulated under the 2012 NSPS.

Similarly, the summary data provided for Allen *et al.* is only for three of the four surveyed wells with a gas to oil ratio under 12,500 scf/barrel.

The EDF/GHGRP is conservative insofar as it is derived from GHGRP data; the GHGRP and Allen et al. studies are conservative for the reasons stated on in part V.A above.

Finally, we consider EDF/Stratus and Brandt et al. to be conservative in their assumption that during completion, oil and gas production gradually increases until, on the final day of completion, production hits the well's initial production rate. Brandt et al. assume a linear increase in production over 9 days of completion; EDF/Stratus assume non-linear ramp up of 7-10 days, equal to 3 days of production. Wells typically hit their highest levels of production during completion and production then declines; thus, assuming that production peaks only on the last day of completion is conservative.

We also note that these values are consistent with what would be expected based gas oil ratios and production. For example, Allen et al. observed production of an average of 1,713 barrels per completion from the four < 12,500 scf/barrel wells in the study.[170] At 1,713 barrels per completion, even for a well with a gas oil ratio in the for black oil range (550 scf/barrel), and using the 2011 TSD's estimate that the gas produced from oil wells is 46.7% methane, one would still expect to 9.2 tons of methane to be produced.

Recompletion emissions will likely vary according to many factors including reservoir drive mechanism, gas production and decline rate, method of recompletion, and others. Very little data exists on recompletion emissions. Notably, the gas-oil ratio increases as oil wells age and evolving stimulation methods can

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[166] NSPS Subpart OOOO, § 60.5430.

[167] Oil and Gas Division, Texas Administrative Code, Title 16, Chapter 3, Rule § 3.79.

[168] Alaska Oil and Gas Conservation Commission, Definitions, Alaska Admin. Code Title. 20, § 25.990 defines and oil well as well that produces predominantly oil at a gas-oil ratio of 100,000 scf/bbl or lower, unless on a pool-by-pool basis the commission establishes another ratio.

[169] Oil and Gas, New Mexico Administrative Code Title 19, Chapter 15, January 2013. Regulations define an oil well as "a well capable of producing oil and that is not a gas well as defined in Paragraph (6) of Subsection G of 19.15.2.7 NMAC. A gas well is defined as a well with a GOR of 100,000 scf/bbl.

[170] Whitepaper Table 3-6.

result in recompletions that significantly boost production. We therefore support the use of completion emission factors as an estimate of recompletion emissions.

In light of these studies, it is clear that the oil well completion and recompletion emission factors used in the OOOO TSD and the GHGI are too low. The OOOO TSD estimated only 0.0074 and 0.0011 tons of methane per oil well completion and recompletion, respectively.[171] The OOOO TSD estimate was therefore more than one thousand times lower than the lowest estimate summarized in the whitepapers. The 2014 GHGI emission factor for completions, 0.0141 tons of methane per event, is also clearly not applicable to hydraulically fractured wells.

#### ii. Oil Well Completion Activity Factor

ERG estimates 5,754 uncontrolled oil well completions in 2011.[172] EDF estimates hydraulic fracturing completions of 15,753 oil wells in 2012, with 43% of those, 6,773, being uncontrolled.[173] The 2011 OOOO TSD estimated hydraulic fracturing of 12,193 new oil wells.[174]

It is therefore plain that uncontrolled oil well completion emissions represent a significant source of methane. ERG estimates 44,306 to 138,096 tons of emissions. Brandt et al. estimate 122,733 tons from oil well completion in just three basins. EDF's analysis of GHGRP data estimates 162,570 tons of methane from uncontrolled oil well completions in 2012.[175] Finally, EDF/Stratus estimates 272,270 tons of uncontrolled oil well completion emissions in 2012.

Although data on recompletions is less available, even under the whitepaper's estimate of 0.5% of all oil wells being refractured every year, refracturing represents a significant source of additional emissions.

#### iii. Oil Well Completion Control Technologies

Completion emissions can be easily abated. As recognized by the whitepapers, there are two primary control technologies: reduced emission completions and flares. Both can achieve 95% control efficiencies.[176] Thus, even under the conservative

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[171] 2011, NSPS Subpart OOOO, TSD, at Table 4-6, Page 4-21 (estimating that a flare with 95% control efficiency could achieve emission reductions of 0.007 and 0.001 tons per event).

[172] Note that the whitepaper misquotes the ERG activity factor on page 13, indicating 5274 uncontrolled completions. The correct figure is used elsewhere, and all calculations appear to reflect the correct value.

[173] http://blogs.edf.org/energyexchange/files/2014/03/EDF-Co-producing-Wells-Whitepaper.pdf at 8.

[174] 2011, NSPS Subpart OOOO, TSD, at Table 4-4, Page 4-13.

[175] Summarized in http://blogs.edf.org/energyexchange/files/2014/03/EDF-Co-producing-Wells-Whitepaper.pdf at 8

[176] Allen et al. observed higher efficiencies for reduced emission completions--97.8% to 98.8%. Whitepaper at 18.

assumptions above, the abatement potential for oil well completions is well over 100,000 tons of methane per year.

This abatement can be achieved at reasonable costs. Reduced emission completions are the more expensive, but still reasonable, option. The 2011 TSD estimated that a reduced emission completion cost $29,713 and achieved a 95% control efficiency.[177] The minimum, median, and maximum estimates of per-completion emissions we provide above are 7.7, 24, and 213.3 tons of methane. These respectively entail control costs of $4,061, $1,303, and $146 per ton of methane, *without* considering offsetting revenue from captured gas. If captured gas is sold at $4/Mcf, then costs fall to $2,581/ton in the 7.7 ton case, and reduced emission completions turn an immediate profit in the other cases.

Of course, a more sophisticated analysis would recognize that both cost of reduced emission completion equipment and the tonnage of methane at issue correlate with completion time. As summarized by the whitepaper, the cost of a reduced emission completion depends on whether the needed equipment is already on-site and the length of time the equipment is needed for. Here, we use the per-day costs of a reduced emission completion from the whitepaper. As noted above, the estimates of emission volumes are already conservative. An additional reason why the high per-day cases are conservative is that it is unlikely that the per-day cost will increase linearly for longer completion periods. That is, the longer that wells in a formation take to complete, the greater the likelihood that reduced emission completion equipment will be available nearby, and the greater potential economy of scale.

| Study | Time | Avg. CH4 | REC cost (low) | $ per ton | REC cost (high) | $ per ton |
|---|---|---|---|---|---|---|
| ERG/ECR | 7 | 24 | 5,642 | 235.08 | 52,402 | 2,183.42 |
| ERG/ECR | 3 | 7.7 | 2,418 | 314.03 | 22,458 | 2,916.62 |
| EDF/Stratus Analysis of HDPI (Eagle Ford)[178] | 8.5 | 19.8 | 6,851 | 346.01 | 63,631 | 3,213.69 |

[177] EPA, Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution, Background Technical Support Document for Proposed Standards (April 2012), Pp. 5-2,3. Available at http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf.

[178] EDF/Stratus state that they assumed 7 to 10 days of completion; we use 8.5 as the average.

| | | | | | | |
|---|---|---|---|---|---|---|
| EDF/Stratus Analysis of HDPI (Wattenberg) | 8.5 | 27.2 | 6,851 | 251.88 | 63,631 | 2,339.38 |
| EDF/Stratus Analysis of HDPI (Bakken) | 8.5 | 10.5 | 6,851 | 652.48 | 63,631 | 6,060.1 |
| EDF/Stratus Analysis of HDPI (weighted average) | 8.5 | 17.3 | 6,851 | 396.01 | 63,631 | 3,678.09 |
| Allen[179] | 3 | 213.3 | 2,418 | 11.34 | 22,458 | 105.29 |
| Brandt et al. (Eagle Ford) | 9 | 100.2 | 7,254 | 72.4 | 67,374 | 672.4 |
| Brandt et al. (Bakken) | 9 | 34.4 | 7,254 | 210.87 | 67,374 | 1958.55 |
| Brandt et al. (Permian) | 9 | 34.3 | 7,254 | 211.49 | 67,374 | 1964.26 |

Finally, for one more interpretation of the data, we note that EDF/Stratus found that costs of emission reduction using reduced emission completions remain reasonable even for median, rather than average, wells.[180]

The other control option is flaring. In the technical support document for the 2012 NSPS, EPA estimated this cost, for oil well completions, at $3,523 per well.[181] Like reduced emission completion, combustion is generally at least 95% effective. For the range of emission estimates provided above, combustion provides control costs of $482 to $17 per ton.

### iv. Gas Emissions During Oil Well Production

GHGRP data shows that emissions of methane from venting of associated gas were 90,000 tons in 2011 and 175,000 tons in 2012.[182] Most of this venting is "casinghead gas venting" from older oil wells. These reported emissions, which are a lower limit of national emissions since smaller producers do not report emissions to the GHGRP, are considerably larger than the "stripper well" emissions in the USGHGI (14,200 tons of methane in 2011). It is not known why the reported emissions vary so significantly between 2011 and 2012. We agree it may be possible to provide additional estimates of associated gas emissions using gas to oil ratios or

[179] Average of four oil wells studied. Whitepaper at 18

[180]

[181] 2011, NSPS Subpart OOOO, TSD, at Table 4-6, Page 4-21.

[182] Some portion of this is due to methane emissions from flares of associated gas (due to incomplete combustion).

other reporting.[183] Refining these estimates need not precede regulation of these emissions, however.

### v. Alternatives to Flaring

For both completion and production emissions, the preferred alternative control for associated gas is capture. Typically, gas that is captured during oil well completions and production is transported to processing plants in gathering pipelines. When wells are isolated or other issues limit the capacity of gathering systems, other technologies can make it feasible to utilize associated gas locally or get it to market for beneficial use.

The Oil White Paper references several technologies that can be used as alternatives to flaring: natural gas liquid recovery, natural gas reinjection, and electricity generation for on-site use. Natural gas reinjection may be viable, although additional research and testing may be needed to scale up this option for unconventional reservoirs.

The White Paper also excluded two important technologies that can be used at well pads to reduce flaring:

- Compressed natural gas (CNG) trucking – compressing associated gas at wellsites and trucking to consumers, processors, gathering systems, etc.

- Electric power generation for sale to grid.

Natural gas liquid recovery, compressed natural gas (CNG) trucking, electricity generation for on-site use, and electric power generation for sale to grid are all mature technologies, having been deployed commercially more than once in tight oil developments. These technologies can also be scaled up or down depending on the size of the development. Finally, many of the technologies are portable: they can be moved from well to well. For example, a technology can be deployed at a well in the first few months, when gas production is very high, and dismantled or scaled down once a pipeline is in place and can handle the full volume of production from the well. These solutions represent practices that are feasible today at costs that are not prohibitive.

Even if capture for on-site use or in gathering pipelines is infeasible or EPA otherwise chooses not to require it, flaring remains a much better alternative than venting from a pollution perspective. A Federal Implementation Plan (FIP) for the Fort Berthold Indian Reservation (FBIR) reports that flaring requirements for associated gas during production have an abatement cost for VOC of $10-$17 per

[183] See Whitepaper at 20-21.

ton.[184] Using the OOOO ratio of methane to VOC for oil well completions and recompletions,[185] methane abatement costs would be $9 - $16 per ton.

However, we note that flaring is still an inherently wasteful process which produces large amounts of carbon dioxide, nitrogen oxides, particulate matter including black carbon, and other pollutants. Flares' flames can be extinguished by weather or interruptions in flow, and even if auto-igniters are required (they are not in many jurisdictions) the emissions from flares that go out for periods of time during operations should be considered.

Alternatives to flaring, such as gathering systems and the alternative approaches identified in the white paper and above, must be considered for any well before routine flaring is considered. Further, flaring, which produces voluminous pollution, should not be allowed simply because an alternative to flaring has a net cost for a well operator. EPA must consider these alternatives to flaring as systems of pollution control, and compare the *net* cost of installing these alternatives as a means of abating the pollution that the flare would produce.

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[184] TSD for FBIR FIP, table 4. Available at http://www.regulations.gov/#!documentDetail;D=EPA-R08-OAR-2012-0479-0004.
[185] From OOOO RIA (2011), table 3-3.

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