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Re: General Plan Approval and General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (GP-5A) and for Natural Gas Compressor Stations, Processing Plants, and Transmission Stations (GP-5)

Dear Mr. McDonnell, Ms. Shirley, Mr. Ramamurthy, Mr. Bhatt and Mr. Boritz:

The following comments are submitted by Clean Air Council, Environmental Defense Fund, Clean Air Task Force, PennFuture, Earthworks, Natural Resources Defense Council, and Sierra Club in response to the Pennsylvania Department of Environmental Protection's ("Department" or "DEP") draft general permits, GP-5 and GP-5A. We sincerely appreciate your consideration of these comments, as the proposed permits are a critical first step toward fulfilling Governor Wolf's promise to reduce methane emissions from Pennsylvania's oil and gas sector. Solutions are necessary as, just last month, DEP released emissions inventory data for 2015, which show that methane emissions from the unconventional natural gas industry increased by twenty-eight percent (28%) year-over-year from 2014.[1] The comments contained herein build on discussions and recommendations shared with the Department in meetings on December 21, 2016, and April 26, 2017; these comments also track closely the written comments that we submitted on January 9, 2017, supplemented with additional information.

First, we commend DEP for proposing a strong set of requirements that will go a long way towards protecting the public and the environment from deleterious effects associated with

[1] *See* Pennsylvania Department of Environmental Protection, "Air Emissions Data from Natural Gas Operations," available at: http://www.dep.pa.gov/Business/Air/BAQ/BusinessTopics/Emission/Pages/Marcellus-Inventory.aspx

harmful oil and gas emissions. We strongly support many aspects of the proposed permits, which we acknowledge are in line with requirements implemented in other leading states. In particular, we commend DEP on directly controlling methane from a suite of equipment found at well sites, compressor stations and pigging stations. Methane is a potent greenhouse gas that is 28-36 times more potent than carbon dioxide on a 100-year timeframe and 84 times more potent on a 20-year timeframe. The proposed requirements will significantly help reduce the emissions of this harmful climate pollutant.

We also strongly support the replacement of Air Quality Permit Exemption Category No. 38 ("Exemption 38") with general permit requirements for unconventional well sites. The requirements contained in GP-5A are more protective and comprehensive than those contained in Exemption 38, and the use of a permit mechanism will provide a much needed opportunity for upfront oversight of well site air impacts and allow outside groups such as ours to participate in that review. Although a general permit does not allow for public comment on permits issued to individual facilities, the approach represents an improvement over Exemption 38, which has allowed operators to submit compliance demonstrations 6 months after a facility is operating and polluting. Such a change has the potential to result in both substantial emissions reductions and cost savings.

In addition to securing much-needed reductions in methane, and providing for better oversight of unconventional well sites, the proposed requirements will help reduce emissions that contribute to ground-level ozone or smog. Volatile organic compounds (VOCs) and nitrogen oxides (NOx) react within the atmosphere to create smog, which can cause a variety of respiratory problems and cardiovascular effects, including: decreased lung function, aggravated asthma, coughing and shortness of breath, increased hospital admissions, cardiac arrhythmia, and increased risk of heart disease, heart attacks, and strokes. Based on self-reported data, the unconventional natural gas industry in Pennsylvania emitted 6,431 tons of VOCs and 20,067 tons of NOx in 2015 alone.[2] We support DEP's decision to include in GP-5 and GP-5A controls on VOCs and NOx that will help Pennsylvanians breathe easier.

The proposed permit requirements will also result in critical public health protections by requiring that operators install controls that will reduce hazardous air pollutants ("HAP"). HAPs, also known as toxic air pollutants or air toxics, are known carcinogens that can cause a wide range of other health impacts; these include irritation of the eyes, nose, and throat, headaches and lightheadedness, immunological problems, and effects on fetal and child development. HAPs are emitted as byproducts of combustion, through the venting or processing of natural gas, and as a result of fugitive emissions. Natural gas operators reported releasing at least 623 tons of HAPs[3] in 2015 and, given the serious health risks posed by these air toxics, we strongly support the HAPs controls included in the proposed permits. Also, although not directly targeted, emissions of sulfur oxides (SO_x) and particulate matter ($PM_{2.5}$ and PM_{10}) are likely to be reduced through implementation of the proposed permit conditions.[4]

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[2] *Ibid.*

[3] Note that Pennsylvania operators are required to report only a limited set of HAP emissions.

[4] Short-term exposure to SOx can cause respiratory problems, making breathing difficult and exacerbating asthma symptoms, while particle pollution can cause serious damage by entering the lungs and bloodstream.

We also support DEP's decision to promulgate standards to cover emissions sources previously uncontrolled in Pennsylvania, including: (1) reciprocating compressors located at well sites; (2) wellbore liquids unloading operations; (3) pigging operations; and (4) facilities in the natural gas transmission segment. With data suggesting emissions from such sources are significant, it is critical for these sources to be subject to control and monitoring requirements. Other leading states already require that operators take steps to minimize venting from these sources and we commend Pennsylvania for doing so as well.

Specifically on liquids unloading operations, GP-5A will require operators to incorporate best management practices and have personnel remain onsite during any manual venting episode. Colorado and Wyoming have imposed similar requirements in recent years and, according to Wyoming regulators, this has helped significantly reduce liquids unloading emissions. Similarly, we strongly support DEP requiring a control efficiency of 98% or greater for methane, VOC, and HAP emissions from pigging operations and newly constructed glycol dehydration units and storage vessels; this common sense standard, which also aligns with requirements in Wyoming and Colorado, will control pollution while helping operators avoid unnecessary waste of their product.

We also support DEP establishing a quarterly leak detection and repair ("LDAR") inspection frequency in GP-5 for compressor stations and in GP-5A as a baseline frequency for well sites. Wyoming and Colorado have already implemented quarterly inspections at medium-sized well sites and compressor stations, while California most recently adopted a quarterly inspection frequency for all production facilities. Multiple studies have shown that quarterly LDAR at both new and existing facilities is a highly cost-effective way to reduce emissions. By proposing a baseline quarterly inspection frequency for well sites, and a quarterly inspection requirement for compressor stations, Pennsylvania is catching up to other leading states.

Going forward, we hope these efforts will provide necessary momentum for DEP to expeditiously propose similar common sense controls for methane emissions from all existing sources in the oil and gas sector. Methane emissions from unmodified existing facilities will not be affected by GP-5 or GP-5A, while the pollution from such operations will continue to impact Pennsylvania residents on a daily basis. Technologies and practices that have proven feasible are available to significantly reduce pollution from these sources at very low cost, so there is no reason that Pennsylvanians should continue to suffer the harms resulting from existing source pollution.

For all the foregoing reasons, we commend DEP for its drafts of GP-5 and GP-5A. Nonetheless, in so doing, we respectfully request that you consider the following recommendations for strengthening and, in some instances, clarifying the drafts. We appreciate the Department's consideration and look forward to working with agency staff to support Pennsylvania in establishing cost-effective standards to reduce methane pollution and protect public health.

I. Leak Detection and Repair

DEP's draft standards in GP-5 and GP-5A require a quarterly inspection frequency with one of three types of leak detection methods: OGI, a gas leak detector that meets the requirements of Method 21, or another approved device. Operators must adhere to detailed requirements to ensure their leak detection devices are operating properly, retain detailed records of each inspection, tag or retain digital photographs of each component on the delayed repair list, and submit records in annual reports. GP-5A allows well site operators to reduce the inspection frequency to semi-annual if the percentage of leaking components is less than 2.0% for two consecutive inspections. The inspection frequency reverts to quarterly if at any time the percentage of leaking components is higher than 2.0%.

We support DEP's efforts to establish a robust leak detection and repair (LDAR) program, and in particular we strongly support the quarterly inspection requirement in GP-5A. A number of leading states require quarterly inspections; analysis prepared by such states, as well as by independent consulting groups and leading operators, demonstrates that quarterly inspections are cost effective. In addition, numerous scientific studies demonstrate that equipment and components can fail or operate abnormally on unpredictable schedules and across facility and equipment types. Such events can contribute very significant emissions, far in excess of estimates that rely on emission factors. Indeed, a recent study in the Barnett Shale found leaks to be over 50% greater than estimated in EPA's national GHG inventory. This and many other studies relying on direct measurement underscore the critical need for operators to frequently, if not continuously, inspect facilities for abnormal operating conditions, repair any such conditions expeditiously, and document and report the results of inspections. Robust, detailed recordkeeping and reporting requirements are critical to compliance monitoring and enforcement. They also provide important information on the efficacy of LDAR programs, and for these reasons, we strongly support the proposed recordkeeping and reporting requirements.

We offer below suggestions on improving the strength and protectiveness of the LDAR provisions in both draft GPs. Specifically, we urge DEP to:

(1) Remove the provision in GP-5A that allows operators to decrease the inspection frequency to semi-annual based on the percentage of leaking components;
(2) Increase the inspection frequency in GP-5A and GP-5 to monthly for the largest facilities; and
(3) Expand the definition of fugitive monitoring component to include continuous and intermittent bleed pneumatic devices.

<u>Quarterly Inspections are Necessary to Identify and Promptly Repair Leaks</u>

We recommend adoption of a quarterly inspection frequency with no opportunity for less frequent monitoring. The scientific consensus, based on numerous studies involving direct measurement of oil and gas leaks, demonstrates the heterogeneous, unpredictable, and ever-shifting nature of equipment leaks. These characteristics strongly point toward the need for frequent, *if not continuous*, inspections to identify and repair leaking components and equipment. Specifically:

- **Leaks are Heterogeneously Distributed.** There is considerable evidence that emissions from equipment leaks are heterogeneously distributed—with a small percentage of sources accounting for a large portion of emissions[5]—and that existing inventories do not accurately reflect the presence of these "super-emitters."[6] A recent series of studies in the Barnett Shale region in Texas—incorporating both top-down and bottom-up measurement—found that emissions were 50 percent greater than estimates based on the GHGI.[7] One study in particular found that a small number of sources are responsible for a disproportionate amount of emissions, noting specifically that "sites with high proportional loss rates have excess emissions resulting from abnormal or otherwise avoidable operating conditions, such as improperly functioning equipment."[8] The concentration of emissions within a relatively small proportion of sources has been observed both among groups of components within a site and among groups of entire facilities.[9]

- **Equipment Leaks are Unpredictable**. Recent studies have assessed whether well characteristics and configurations can predict super-emitters, concluding that they are only weakly related,[10] and that these emissions are largely stochastic. In particular, the

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[5] Allen, D.T., *et al.*, (2013) "Measurements of methane emissions at natural gas production sites in the United States," *Proc. Natl. Acad.*, **110**, ("Allen (2013)"), *available at* http://www.pnas.org/content/110/44/17768.full; ERG and Sage Environmental Consulting, LP, "City of Fort Worth Natural Gas Air Quality Study, Final Report" ("Fort Worth Study") (July 13, 2011), *available at* http://fortworthtexas.gov/gaswells/default.aspx?id=87074 (finding that the highest 20 percent of emitting sites account for 60–80 percent of total emissions from all sites; the lowest 50 percent of sites account for only 3–10 percent of total emissions); Zavala-Araiza, *et al.*, (2015) "Toward a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites," *Environ. Sci. Technol*., 49, at 8167−8174 ("Zavala-Araiza (2015)"), *available at* http://pubs.acs.org/doi/pdfplus/10.1021/acs.est.5b00133 (finding that "functional super-emitter" sites represented approximately 15% of sites within each of several different "cohorts" based on production, but accounted for approximately 58 to 80% of emissions within each production cohort); Zavala-Araiza et al., (2015) "Reconciling divergent estimates of oil and gas methane emissions," Proceedings of the National Academy of Sciences, vol. 112, no. 51, 15597 at 15600 (finding that "at any one time, 2% of facilities in the Barnett region are responsible for 90% of emissions, and 10% are responsible for 90% of emissions.") ("Barnett Synthesis").

[6] Barnett Synthesis *supra* note 5 at 15599.

[7] Harriss, *et al.*, (2015) "Using Multi-Scale Measurements to Improve Methane Emissions Estimates from Oil and Gas Operations in the Barnett Shale, Texas: Campaign Summary," *Environ. Sci. Technol.*, **49**, ("Harriss (2015)"), *available at* http://pubs.acs.org/doi/abs/10.1021/acs.est.5b02305http://pubs.acs.org/doi/abs/10.1021/acs.est.5b02305http://pubs.acs.org/doi/abs/10.1021/acs.est.5b02305 (providing a summary of the 12 studies that were part of the coordinated campaign).

[8] Zavala-Araiza (2015), at 8167−8174.

[9] *See* EPA, "Oil and Natural Gas Sector Leaks: Report for Oil and Natural Gas Sector Leaks" (2014), *available at* http://www3.epa.gov/airquality/oilandgas/2014papers/20140415leaks.pdf.

[10] Lyon, *et al.*, (2015), "Constructing a Spatially Resolved Methane Emission Inventory for the Barnett Shale Region," *Environ. Sci. Technol.*, **49**, at 8147-57, *available at* http://pubs.acs.org/doi/pdf/10.1021/es506359c; *See also* Brantley, H.L., *et. al.*, "Assessment of methane emissions from oil and gas production pads using mobile measurements," Environmental Science & Technology, 48(24), pp.14508-14515, *available at* http://pubs.acs.org/doi/abs/10.1021/es503070q (assessing where well characteristics can predict emissions, concluding that they are weakly related and that emissions are largely stochastic); Zavala-Araiza (2015) ("large number of facilities in the Barnett region cause high emitters to always be present, and these high-emitters seem to

Barnett coordinated campaign mentioned above found that abnormal operating conditions, such as improperly functioning equipment could occur at different points in time across facilities.[11] As a result, Zavala-Araiza, et al. reported that inspections need "to be conducted on an ongoing basis" and "across the entire population of production sites."[12] In addition, a recent helicopter study of 8,220 well pads in seven basins, including 2,067 well pads in the southwest PA region of the Marcellus Basin, confirms that leaks occur randomly and are not well correlated with characteristics of well pads, such as age, production type or well count.[13] That study focused only on very high emitting sources, given the helicopter survey detection limit which ranged from 35–105 metric tons per year of methane. The paper reported that emissions exceeding the high detection limits were found at 327 sites. 92 percent of the emission sources identified were associated with tanks, including some tanks with control devices that were not functioning properly and so could be expected to be addressed through a leak detection and repair program. While the study did not characterize the individually smaller but collectively significant leaks that fell below the detection limit, it nonetheless confirms that high-emitting leaks occur at a significant number of production sites and that total emissions from such leaks are very likely underestimated in official inventories.

- **Super-Emitters Shift in Time and Space**. Abnormal operating conditions, such as improperly functioning equipment, can occur at different points in time across facilities.[14] While it is true that at any one time roughly 90% of emissions come from 10% of sites, these sites shift over time and space—meaning that, at a future time, a different 10% of sources could be responsible for the majority of emissions.[15]

Other studies confirm these findings[16] and underscore the importance of frequent, if not continuous, inspections to identify and repair stochastic, heterogeneous leaks.

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be spatially and temporally dynamic. . . .To reduce those emissions requires operators to quickly find and fix problems that are always present at the basin scale but that appear to occur at only a subset of sites at any one time, and move from place to place over time.").

[11] Harriss (2015), *supra* note 7.

[12] Zavala-Araiza (2015), *supra* note 8, at 8167−8174.

[13] Lyon, et al., "Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites," *Environ. Sci. Technol.*, 2016, *50* (9), pp 4877–4886, available at

http://pubs.acs.org/doi/abs/10.1021/acs.est.6b00705.

[14] Barnett Synthesis, *supra* note 5 at 15600.

[15] *Id*.

[16] Allen, D.T. et al., "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquid Unloadings," *Environ. Sci. Technol*., (2015), 49 (1), pp 641–648, available at http://pubs.acs.org/doi/abs/10.1021/es504016r; Mitchell, A.L., et al, (2015) "Measurements of Methane Emissions from Natural Gas Gathering Facilities and Processing Plants," *Environ. Sci. Technol*, 2015, 49 (5), pp 3219–3227, available at http://pubs.acs.org/doi/abs/10.1021/es5052809; R. Subramanian, et al, (2015) "Methane Emissions from Natural Gas Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol," *Environ. Sci. Technol*, available at http://pubs.acs.org/doi/abs/10.1021/es5060258.

1. *Numerous Leading States Require Quarterly Inspections*

A quarterly inspection schedule would put Pennsylvania operators on par with those in other gas producing states such as Wyoming[17] and Colorado,[18] at least for mid-sized facilities, as well as California.[19]

- **Colorado** requires that operators inspect for and repair hydrocarbon leaks, consisting of methane as well as other organic compounds, at three types of facilities: compressor stations, well sites, and storage tank batteries. The rules require quarterly inspections at mid-sized facilities.[20] The size of the facility is determined based on the potential to emit volatile organic compounds (VOCs), although operators are required to repair hydrocarbon leaks including leaks from components that primarily emit methane.[21]

- **Wyoming** requires quarterly instrument-based inspections at all new and existing well sites in its Upper Green River Basin with the potential to emit 4 tons of VOCs from fugitive components.[22] Operators may use either Method 21 or an optical gas imaging instrument, or other approved instrument.

- **California** recently finalized a rule requiring operators in the production and processing segments, as well as those operating compressor stations in the gathering and boosting and storage and transmission segments, to conduct quarterly inspections to detect methane emissions.[23] Operators may use either Method 21 or an optical gas imaging instrument, or other approved instrument.[24]

2. *Quarterly Inspections Are Cost Effective*

Information from other states, leading operators and independent consulting groups demonstrates that quarterly inspections are highly cost effective.

- **Colorado**. The final cost benefit analysis prepared by the Colorado Air Pollution Control Division in support of its LDAR program demonstrates that quarterly inspections are cost effective. For mid-sized well sites, Colorado found the cost effectiveness of quarterly LDAR inspections to be $1,019 per ton of VOC reduced and $679 per ton of

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[17] Wyoming Department of Environmental Quality, Air Quality Division Standards and Regulations, Nonattainment Area Regulations, Ch. 8, §(6)(g)(1)(a); Wyo. Dep't of Envtl. Quality, Oil and Gas Production Facilities: Chapter 6 Section 2 Permitting Guidance (June 1997, Revised May 2016) ("WY Permitting Guidance"), 22, *available at* http://deq.wyoming.gov/media/attachments/Air%20Quality/New%20Source%20Review/Guidance%20Documents/2013-09_%20AQD_NSR_Oil-and-Gas-Production-Facilities-Chapter-6-Section-2-Permitting-Guidance.pdf

[18] Colorado 5 C.C.R. 1001-9, Reg. 7, § XVII.F.4.a (Feb. 24, 2014). Quarterly inspections are required at gathering sector compressor facilities with uncontrolled emissions between 12 and 50 tons of VOCs from equipment leaks and at well sites and tank batteries with uncontrolled emissions between 20 and 50 tons of VOCs from the largest condensate or oil storage tank onsite.

[19] CARB 17 C.C.R. § 95669(g), available at https://www.arb.ca.gov/regact/2016/oilandgas2016/oilgasappa.pdf.

[20] *See supra* note 18.

[21] *See Id*., at XVII.a.5.

[22] WY Permitting Guidance; Wyoming Department of Environmental Quality, Air Quality Division Standards and Regulations, Nonattainment Area Regulations, Ch. 8, Sec. 6.

[23] CARB § 95668(g).

[24] *Id*.

CH4/ethane reduced for facilities located in the Denver nonattainment area. For remote facilities located outside the nonattainment area, Colorado determined quarterly inspections to be cost effective at $1,268 per ton of VOC reduced and $648 per ton of CH4/ethane reduced.[25]

- **California**. Similarly, the California Air Resources Board has found that the cost of conducting quarterly inspections at production facilities to be highly cost effective. CARB estimates the cost are $14 per metric ton of CO2e reduced (accounting for savings from recovered product) to $17 per metric ton of CO2e reduced (not accounting for savings).[26] These estimates assume a 20-year global warming potential for methane.

- **ICF International.** In 2015, EDF commissioned ICF to develop a stochastic model to estimate the cost-effectiveness of LDAR at different types of facilities.[27] The analysis seeks to develop facility models that replicate real world situations and capture variations in these characteristics by using a Monte Carlo simulation to analyze facility emissions, reductions and costs. The attached power point describes the model inputs and assumptions underpinning each of the analyzed scenarios and sets forth results. *See* Exhibit 1. EDF converted ICF's cost effectiveness estimates into dollars per short tons of methane and determined that quarterly inspections are equal to $262 per short ton of methane reduced, assuming $3 gas; $234 per short ton of methane reduced, assuming $4 gas, and $187 per short ton of methane reduced, assuming $3 gas and the use of a contractor to perform the inspection. *See* Exhibit 1.

- **Carbon Limits**. This study is based on actual leak data from over 4,000 leak detection and repair (LDAR) inspections of oil and gas facilities, such as well sites, gas compressor stations, and gas processing plants. The inspectors used infrared cameras to identify over 58,000 individual components that were leaking or venting gas. The inspection firms provided facility inspection costs and, for every leak they found, data such as the size of the leak and how much it would cost to repair. LDAR surveys performed quarterly would abate methane at a net cost of less than $280 per metric ton ($11/ton CO2e using a global warming potential of 25) for all types of facilities. Per this study, over 90% of the gas leaking from these facilities is from leaks that can be fixed with a payback period of less than one year (assuming gas prices of $3 per thousand cubic feet).[28]

- **Center for Methane Emissions Solutions**, **Colorado Case Study**. CMES interviewed 10 companies in Colorado operating after Colorado adopted its leak detection and repair program in 2014. It found that 7 out of 10 companies interviewed reported that

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[25] Colorado Air Pollution Control Division, Cost-Benefit Analysis for Proposed Revisions to AQCC Regulations No. 3 and 7 (February 7, 2014) ("CAPCD Cost-Benefit"), at 28, Table 34, *available at* ftp://ft.dphe.state.co.us/apc/aqcc/Oil%20&%20Gas%20021914-022314/COST%20BENEFIT%20ANALYSIS%20&%20EXHIBITS/CDPHE%20Cost-Benefit%20Analysis_Final.pdf.

[26] California Air Resources Board Economic Analysis for Proposed Rules, 2016, Table 14, available at https://www.arb.ca.gov/cc/oil-gas/Oil%20and%20Gas%20ISOR.pdf.

[27] The 2015 analysis, attached as Exhibit 1, is an update to the 2014 report prepared by ICF.

[28] Carbon Limits, Fact Sheet, Fixing the Leaks: What would it cost to clean up natural gas leaks?, available at http://www.catf.us/resources/factsheets/files/LDAR_Fact_Sheet.pdf. Full report available at http://www.catf.us/resources/publications/files/Carbon_Limits_LDAR.pdf.

additional revenues from fixing leaks more than covers the costs of finding and fixing leaks.[29]

- **LDAR Cost Comparisons for Quarterly and Monthly inspections at Well Sites and Compressor Stations.** We calculated and compared costs of quarterly and monthly LDAR programs at well pads and gathering compressor stations. We present costs from four data sources:
  - EPA OOOOa[30],
  - ICF EDF Cost Curve Report[31],
  - Colorado[32], and
  - Carbon Limits[33].

  The studies make different assumptions about the frequency of inspections, the reductions achieved by inspections, the price of gas, and the methane content of gas. To the extent possible, we recalculated abatement costs from all of these studies using the following common assumptions:

  - Quarterly and monthly inspections,
  - 80% reduction for quarterly inspections, 90% reduction for monthly inspections,
  - 82.9% methane content of gas (by volume),
  - $4/mcf and $2/mcf price of gas.

  Due to these changes, the costs presented in the table below do not directly match the costs presented in the studies. As illustrated in the table, quarterly LDAR ranges from $143 to $960 per ton methane reduced at well sites and from ($18) to $891 at compressor stations, depending on the data source and gas price assumptions. For the methodology and cost spreadsheet and calculations, refer to Exhibits 2 and 3, respectively.

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[29] Center for Methane Emissions Solutions, Colorado Case Study, available at https://static1.squarespace.com/static/558c5da5e4b0df58d72989de/t/57110da386db43c4be349dd8/1460735396217/Methane+Study.pdf.

[30] Environmental Protection Agency (EPA OOOOa). "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources, Background Technical Support Document for the Final New Source Performance Standards 40 CFR Part 60, subpart OOOOa." (May 2016). See spreadsheet attachments: Final Rule OOOOa TSD Section 4 - OGI Well Pad 050216 and Final Rule OOOOa TSD Section 4 - OGI Compressor Stations 050216. Available at: https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-7631.

[31] ICF International (ICF EDF Cost Curve Report). "Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries." (March 2014). Prepared by for Environmental Defense Fund. Available at: https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.

[32] Colorado Department of Public Health and Environment (Colorado). "COST-BENEFIT ANALYSIS For proposed revisions to Colorado Air Quality Control Commission Regulation Number 3 (5 CCR 1001-5) and Regulation Number 7 (5 CCR 1001-9)." (February 2014). For wellpads, see Tables 27, 29, 30, 31, 34, & 35. For compressor stations, see Tables 23, 25, 26, 32, & 33. Available at: https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-7573.

[33] Carbon Limits. "Quantifying Cost-effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras." (March 2014). Figure 12. Available at: http://catf.us/resources/publications/files/Carbon_Limits_LDAR.pdf.

Facility Type	Data Source	$/metric ton methane					
		Quarterly			Monthly		
		Without value of saved gas	With Value of Saved Gas **(@$2/Mcf)**	With Value of Saved Gas **(@$4/Mcf)**	*Without* value of saved gas	With Value of Saved Gas **(@$2/Mcf)**	With Value of Saved Gas **(@$4/Mcf)**
Well Pads	ICF EDF Cost Model [1]	$456	$340	$225	$844	$728	$612
	EPA OOOOa TSD [1]	$960	$844	$728	$1,903	$1,787	$1,671
	Carbon Limits	$420	$281	$143	$1,195	$1,056	$918
	Colorado [2]	$661	$561	$460	$1,473	$1,372	$1,271
Compressor Stations	ICF EDF Cost Model	$214	$98	-$18	$396	$280	$164
	EPA OOOOa TSD [3]	$891	$775	$659	$1,379	$1,263	$1,147
	Carbon Limits	$550	$413	$276	$1,583	$1,446	$1,309
	Colorado	$502	$409	$316	$1,121	$1,028	$935

[1] Emissions from OOOOa TSD Natural Gas Production Well Site Model Plant

[2] To calculate costs for fixed freq. LDAR at all sites using Colorado data, we had to make assumptions about the amount of methane mitigated at the smallest sites. See footnote 4 in summary document on LDAR.

[3] Emissions from OOOOa TSD Gathering and Boosting Model Plant

3. DEP Should Require Monthly Inspections for the Largest Sites

Similarly, other states, leading operators, and independent analysis support a monthly inspection frequency for the largest well sites and compressor stations.

- **Colorado.** Colorado requires monthly inspections of its largest well sites and compressor stations. In support of these requirements, the Colorado APCD determined that monthly instrument-based inspections are cost effective for well sites with at least 50 tons per year of uncontrolled VOC emissions from the largest storage tank. Colorado determined the cost effectiveness of such inspections as $2,235 per ton of VOC reduced and $1,476 per ton of CH4/ethane reduced for facilities located in the Denver metropolitan nonattainment area.[34] For more remote facilities located outside the nonattainment area, CDPHE determined the cost effectiveness of monthly inspections to be $2,752 per ton of VOC reduced and $1,422 per ton of CH4/ethane reduced.[35]

- **Jonah Energy**. Jonah Energy operates in the Upper Green River Basin in Wyoming. Jonah Energy's Enhanced Direct Inspection & Maintenance ("EDI&M") Program in Wyoming has been ongoing for the last five-and-a-half years and includes a *monthly* LDAR program using instrument-based surveys (i.e., IR camera technology). According to Jonah, "[b]ased on a market value of natural gas of $4/MMBtu, the estimated gas savings from the repair of leaks identified exceeded the labor and material cost of

[34] Colorado Air Pollution Control Division, Cost-Benefit Analysis for Proposed Revisions to AQCC Regulations No. 3 and 7 (Feb. 7, 2014) Table 35, on file with EDF.

[35] *Id*.

repairing the identified leaks" while also significantly reducing pollution.[36] Jonah has reported that this highly cost-effective LDAR program has reduced fugitive VOC emissions from its facilities by over 75%, indicating that methane and other hydrocarbon losses have also been reduced by a similar proportion.[37] Jonah's experience that gas savings from repairs often exceed the cost of performing repairs to identified leaks is also borne out by the Carbon Limits report[38] and analysis carried out by Colorado.[39] There is mounting industry-supplied evidence that frequent LDAR is cost-effective.[40]

- **Carbon Limits**. Monthly surveys of well sites and gas plants have methane abatement costs of around $800 to $900 per metric ton.[41]

4. LDAR should apply to all sources of unintentional venting, including continuous bleed and intermittent vent controllers

We urge DEP to expand the scope of the LDAR program to apply to all sources of unintentional venting, including continuous bleed and intermittent vent pneumatic devices. A series of studies demonstrates that both types of controllers can emit significant emissions when malfunctioning.

Studies have demonstrated significant emissions from improperly operating continuous bleed and intermittent vent controllers. Specifically:

- **Allen *et al* (2015).** As part of the Phase II UT study, an expert review of the controllers with highest emissions rates concluded that some of the high emissions were caused by repairable issues, and "many of the devices in the high emitting group were behaving in a manner inconsistent with the manufacturer's design."[42] For example, some devices not designed to bleed continuously (e.g., intermittent bleed devices) had continuous emissions, which according to the study authors, "could be the result of a defect in the

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[36] Comments submitted to Mr. Steven A. Dietrich from Jonah Energy LLC on Proposed Regulation WAQSR, Chapter 8, Nonattainment Area Regulations, Section 6, Upper Green River Basin Existing Source Regulations (Dec. 10, 2014).

[37] Jonah Energy, Presentation at WCCA Spring Meeting at 16 (May 8, 2015).

[38] Carbon Limits, *Quantifying Cost-effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras*, 16 (Mar. 2014) ("Carbon Limits 2014"), *available at* http://www.catf.us/resources/publications/files/Carbon_Limits_LDAR.pdf.

[39] Colorado Air Pollution Control Division used an entirely different method than Carbon Limits to predict that almost 80 percent of repair costs for well facilities will be covered by the value of conserved gas. *See* CAPCD Cost-Benefit, at Table 30.

[40] Several companies that engaged in the development of Colorado's regulations provided evidence that frequent LDAR is cost-effective. In particular, Noble estimated the cost-effectiveness of Colorado's tiered program at "between approximately $50/ton and $380/ton VOC removed" at well production facilities. (Rebuttal Statement of Noble Energy, Inc. and Anadarko Petroleum Corporation in the Matter of Proposed Revisions to Regulation Number 3, Parts A, B, and C, Regulation Number 6, part A, and Regulation Number 7 Before the Colorado Air Quality Control Commission, at 7).

[41] Carbon Limits, Fact Sheet, Fixing the Leaks: What would it cost to clean up natural gas leaks?, available at http://www.catf.us/resources/factsheets/files/LDAR_Fact_Sheet.pdf.

[42] Allen (2015), *supra* note 16 at 633–640.

system, such as a crack or hole in the end-device's (control valve's) diaphragm actuator, or a defect in the controller itself, such as fouling or wear."[43] Analysis of the study data indicates that average emissions from malfunctioning intermittent devices were almost 40 times higher than average emissions from normally operating intermittent pneumatics.

- **Allen *et al*. (2013)**. This study reported that emissions from low-bleed pneumatic controllers were 270% higher than EPA's emissions factor for these devices— 5.1 scfh.[44] Many low-bleed controllers are specified to emit far less than this: EPA's Gas Star program has documented many low-bleed controller models with bleed rates of less than 3 scfh and, of course, the emissions factor used by EPA for low-bleeds (1.39 scfh)[45] implies that many low-bleeds are expected to emit at a very low level. Assuming that some low-bleed controllers are performing as specified, the high emission rate observed by Allen *et al*. (2013) implies that many "low-bleed pneumatic controllers" are in fact emitting more than the design threshold of 6 scfh for low-bleeds[46]—or much more than 6 scfh—simply to raise the average emission rate to 5.1 scfh.

- **City of Fort Worth Study.** The Fort Worth Study examined emissions from 489 intermittent-bleed pneumatic controllers, using IR cameras, Method 21, and a HiFlow sampler for quantification. The study found that many of these controllers were emitting constantly and at very high rates, even though the devices were being used to operate separator dump valves and were not designed to emit in between actuations.[47] Average emission rates for the controllers in the Fort Worth Study were at a rate approaching the average emissions of a high-bleed pneumatic controller. According to the study authors, these emissions were frequently due to supposedly improperly functioning or failed controllers.[48]

- **British Columbia Study.** The Prasino study of pneumatic controller emissions in British Columbia also noted the potential for maintenance issues leading to abnormally high bleed rates.[49] Although the researchers did not identify a cause for these unexpectedly high emission rates, the results are consistent with the observation that maintenance and operational issues can lead to high emissions.

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[43] *Id.* at 639.
[44] Allen, *et al*. (2013), *supra* note 5, at 17,771-72.
[45] 40 C.F.R. § 98.233(a).
[46] *Id.* § 60.5390(c)(1).
[47] Fort Worth Study, *supra* note 5.
[48] *Id*. at 3-99 to 3-100. ("Under normal operation a pneumatic valve controller is designed to release a small amount of natural gas to the atmosphere during each unloading event. Due to contaminants in the natural gas stream, however, these controllers eventually fail (often within six months of installation) and begin leaking natural gas continually.")
[49] The Prasino Group, *Determining bleed rates for pneumatic devices in British Columbia; Final Report*, (Dec. 18, 2013), at 19, *available at* http://www2.gov.bc.ca/assets/gov/environment/climate-change/stakeholder-support/reporting-regulation/pneumatic-devices/prasino_pneumatic_ghg_ef_final_report.pdf. ("Certain controllers can have abnormally high bleed rates due to operations and maintenance; however, these bleed rates are representative of real world conditions and therefore were included in the analysis.").

- **The Carbon Limits Study.** The Carbon Limits Report confirms these findings and concludes that LDAR programs may help to identify other improperly functioning devices like pneumatic controllers.[50]

The same methods used for leak detection at valves, connectors, and other leaking components and equipment at oil and gas facilities can be used to spot significant operational issues at pneumatic controllers. This is particularly true of intermittent-bleed controllers, where an OGI survey revealing continuous emissions from an intermittent controller can alert operators to the problem. Similar to a protocol for detecting leaks from components never expected to have emissions, intermittent-bleed controllers should be observed for visible emissions including the control box or other vents that normally emit during actuations. If emissions are observed, then a controller should continue to be observed for a period sufficient to determine if the controller is actuating (approximately 1 to 2 minutes). Moreover, if a comprehensive LDAR program is already being implemented at a facility, such as that required under GP-5 and GP-5A, the marginal cost of extending that program to intermittent-bleed pneumatic controllers would likely be very modest, especially if an operator uses an OGI camera or similar technology to detect leaks. The California Air Resources Board requires operators include intermittent vent devices in LDAR: "[b]eginning January 1, 2018, intermittent bleed pneumatic devices shall comply with leak detection and repair requirements specified in section 95669 when the device is idle and not controlling."[51]

Similarly, DEP should require operators to confirm that low-bleed pneumatic controllers are operating as intended and emissions do not exceed 6 scf/h. To do so, we urge DEP to follow CARB's lead. CARB requires operators annually test all continuous bleed natural gas powered pneumatic devices using a direct measurement method (high volume sampling, bagging, calibrated flow measuring instrument), and repair any device with a measured emissions flow rate greater than 6 scf/h within 14 calendar days from the date of measurement.[52]

5. DEP Should Remove Reduced Frequency Step Down Provisions

DEP's proposal creates perverse incentives by rewarding operators for failing to identify harmful leaks. This is not a hypothetical concern. A 2007 report by EPA found "significant widespread non-compliance with [LDAR] regulations" at petroleum refineries and other facilities.[53] EPA observed: "Experience has shown that poor monitoring rather than good performance has allowed facilities to take advantage of the less frequent monitoring provisions."[54] The report recommends that "[t]o ensure that leaks are still being identified in a timely manner and that previously unidentified leaks are not worsening over time," companies

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[50] Carbon Limits (2014), *supra* note 38 at 12.
[51] CARB § 95668(e)(3)

[52] *Id*. at (e)(2)(A).
[53] EPA, "Leak Detection and Repair: A Best Practice Guide," October 2007, at 1, *available at* http://www2.epa.gov/sites/production/files/2014-02/documents/ldarguide.pdf.
[54] *Id.* at 23.

should monitor more frequently.[55] Instead, DEP should establish a rigorous baseline and reward operators for finding leaks more quickly and accurately—maximizing environmental benefits while minimizing costs.

Furthermore, DEP's proposed metric for determining adjusted frequency—the percentage of leaking components— is not an accurate predictor of a facility's emissions performance. At a conceptual level, if emissions from leaking components were homogenously distributed, the percentage of components leaking at a facility would be a good indicator of facility-level emissions. However, there is overwhelming evidence that leak emissions follow a skewed, highly-heterogeneous distribution, with a relatively few number of sources accounting for a large portion of emissions. In such circumstances, the percentage of leaking components will not accurately reflect emissions and should not be used to determine the frequency of LDAR survey requirements.

We empirically examined the effects of percent thresholds using data from the City of Fort Worth Study Air Quality Study,[56] which includes both component level emissions information and site-level data. Figure 1 below shows the results of this analysis. Figure 1 compares site-level emissions to the percentage of leaking components and demonstrates that the individual sites with the highest emissions fall below DEP's proposed 2 percent threshold. Figure 2 aggregates site-level emissions at each of these thresholds. Sites with less than 2 percent leaking components constituted 90% of total emissions and 80% of all sites.

[55] *Ibid*.
[56] Fort Worth Study, *supra* note 5.

Figure 1: Site Methane Emissions (lb per year) Versus Percent Leaking Components

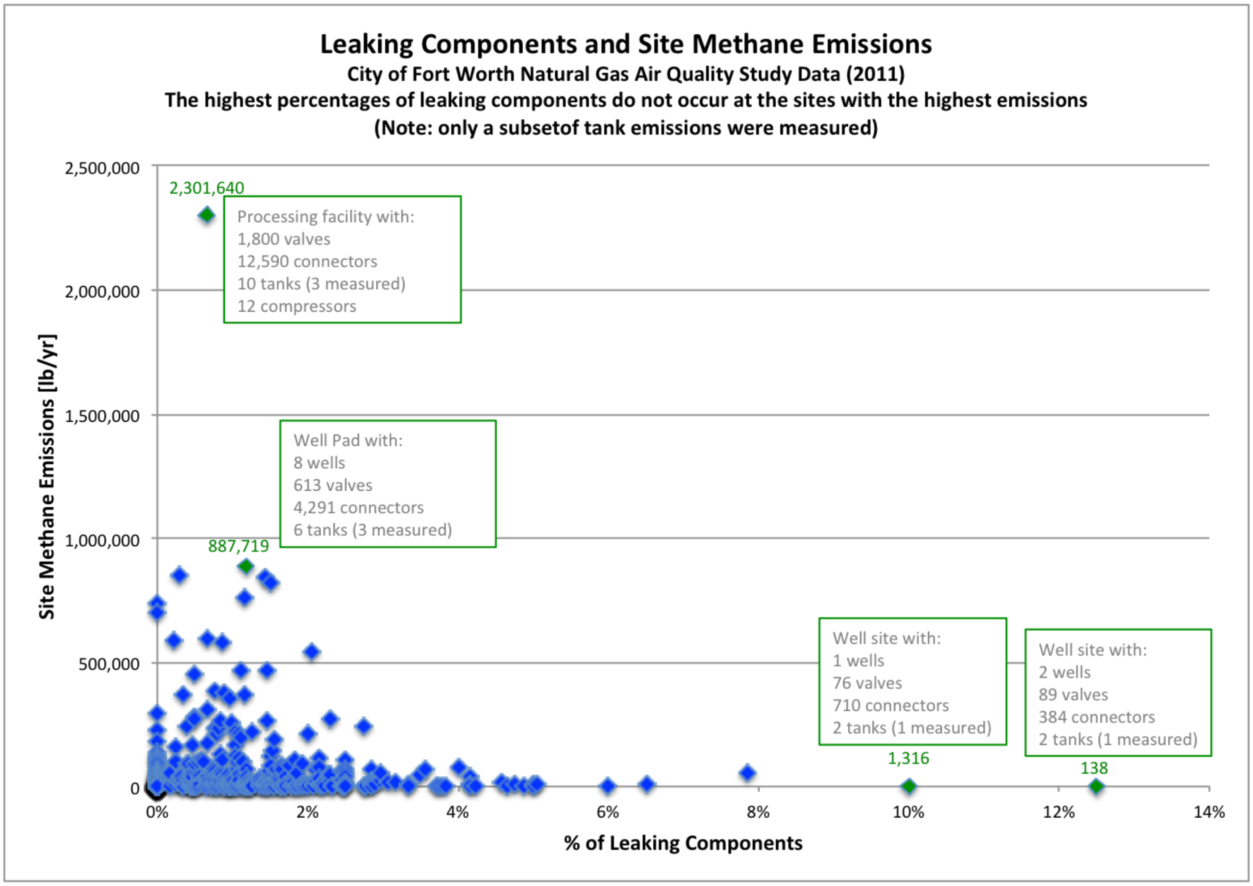
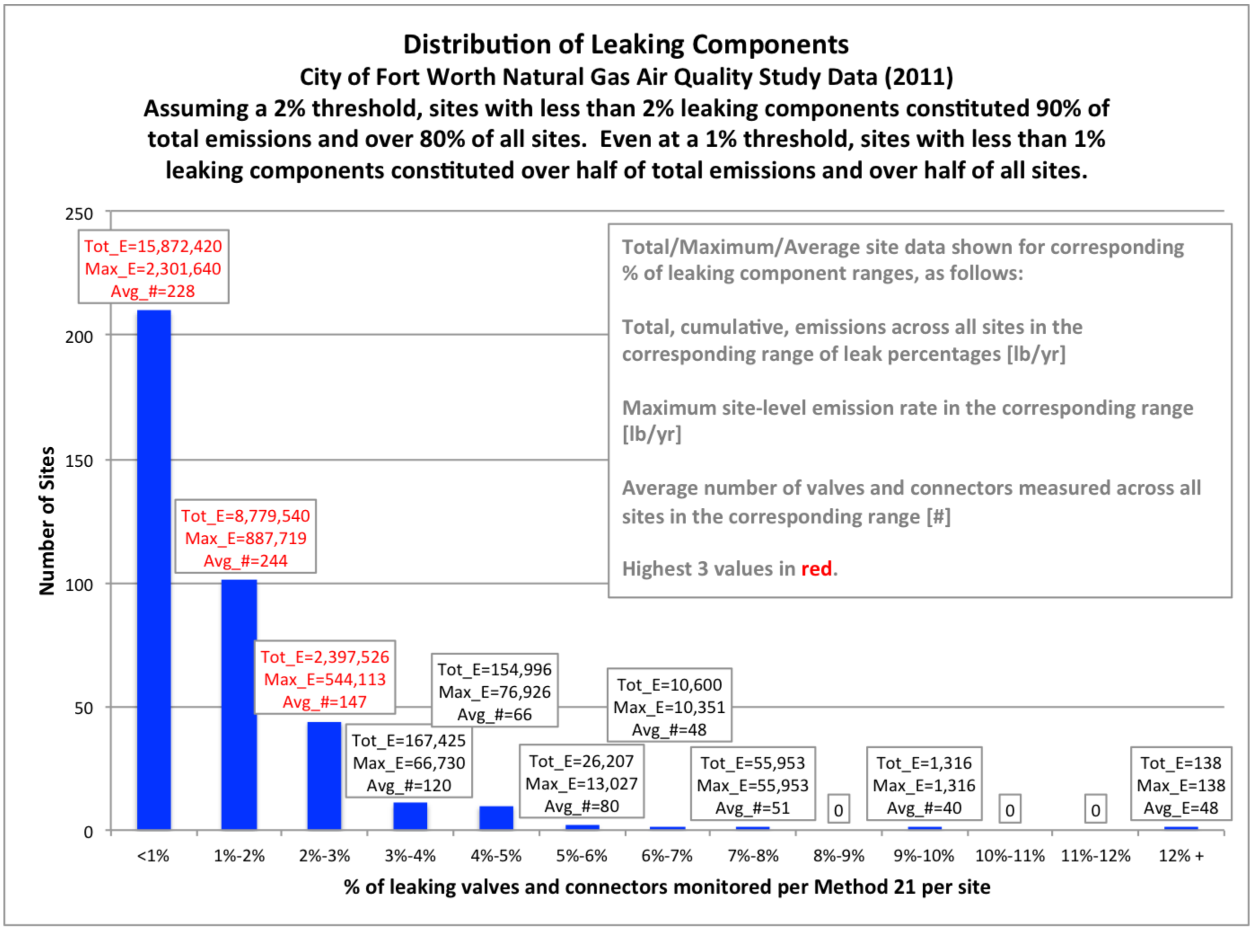


Figure 2: Number of Sites versus Percent of Leaking Valves and Connectors Monitored per Site (Method 21)



Data from operators collected as part of Colorado's LDAR program further support a fixed inspection requirement. Colorado's approach requires operators to inspect for leaks at all but the smallest sites on a fixed annual, quarterly, or monthly basis (depending on the facility's tanks emission potential). 5 C.C.R. 1001-9, CO Reg. 7, §§ XVII.C.2.b.(ii), XVII F, (Feb. 24, 2014). Notably, Encana submitted testimony regarding its own voluntary LDAR program, which requires monthly instrument-based inspections. According to Encana, "[our] experience shows leaks continued to be detected well into the established LDAR program."[57] Encana's data shows that while the largest reductions in VOC emissions occur in the first year of an LDAR program, significant emission reductions are still being realized in subsequent years of the LDAR program – because leaks re-occur at facilities.[58] This pattern was independently confirmed in supplementary analysis carried out by Carbon Limits on leak inspection data from a

[57] Rebuttal Statement of Encana Oil and Gas (USA) Inc., Before Colorado Air Quality Control Commission, Regarding Revisions to Regulation Numbers 3, 7, and 9, at 10.
[58] *Id*. at 10-11.

number of well production facilities and compressor stations.[59] Carbon Limits found that inspectors continued to find leaks in repeat inspections on the same facility. Additionally, Carbon Limits found that the cost-effectiveness of the leak inspections, expressed in dollars per metric ton of VOC abatement, did not significantly rise over several years after regulations were put in place requiring LDAR at facilities in Alberta.

We strongly recommend that DEP remove provisions allowing operators to reduce frequency based on the percentage of leaking components identified in prior surveys. As discussed above, studies suggest that past emissions are not a good predictor of future emissions given the prominent role that improperly functioning equipment, poorly maintained equipment, and other random events play in overall emissions. Facilities with low emissions during one survey may nonetheless experience such an event in the future, and less frequent monitoring at these sites would delay repairs to end these important and harmful emissions. Accordingly, we recommend DEP finalize an LDAR standard based on fixed frequencies.

II. Emissions Threshold for Control for Dehydrators, Tanks, and Pigging Operations.

We commend DEP for directly addressing methane emissions from dehydrators, tanks, and pigging operations in the proposed GP-5 and GP-5A. As we have detailed previously, methane is a very harmful climate pollutant. While it is also critical to reduce emissions of toxic air pollutants and smog-forming VOCs from oil and gas facilities, certain pollution streams from some oil and gas facilities, such as from "dry" (low-VOC) natural gas production facilities, which are numerous in Pennsylvania, are predominantly methane. It is therefore very important that DEP has proposed direct methane standards for new and modified unconventional facilities and compressor stations.

We also commend DEP for recognizing that, given the harm caused by VOCs and toxic air pollutants, sources of these pollutants should be covered by protective standards and DEP has proposed standards for sources such as tanks, dehydrators, and pigging operations with a threshold of 2.7 tons of VOCs per year. A low standard is appropriate given the harm caused by VOC emissions and co-emitted hazardous air pollutants, and given the very low cost of controlling VOC from these sources relative to others that cannot be controlled with devices that actually *increase revenue for facility operators.*

However, there are two significant shortcomings with these standards as proposed. First, any applicability threshold should be set not for an individual tank or dehydrator, but rather for

[59] Colorado Department of Public Health and Environment, Index of /apc/aqcc/Oil & Gas 021914-022314/REBUTTAL STATEMENTS, EXHIBITS & ALT PROPOSAL REVISIONS/Conservation Group. Supplemental Testimony of David McCabe, at 734-736, *available at* ftp://ft.dphe.state.co.us/apc/aqcc/Oil%20&%20Gas%20021914-022314/REBUTTAL%20STATEMENTS,%20EXHIBITS%20&%20ALT%20PROPOSAL%20REVISIONS/Conservation%20Group/Conservation%20Groups%20-%20REB%20Exhibits.pdf.

the sum of all sources. Second, the 200 ton per year (tpy) threshold for methane emissions is far too high.

1. Threshold for Applicability Should Be Applied to All Vented Sources at a Facility

It is particularly important to consider all venting from a site because equipment to capture or control emissions from these sources can, in general, be used to handle gases from multiple sources. Pollution control devices such as enclosed flares, provided they are adequately sized, can handle vapors from essentially any vented source. Capture systems such as VRUs, which are a superior approach because they conserve gas and result in less pollution (see below), can be used to handle vapors from almost any vented source with the exception of dehydrators. Another superior approach, directing vapors to a heater or boiler, can be used for all vented sources, including dehydrators. In general, this approach is as simple as manifolding lines from multiple vented sources to feed a common VRU, heater / boiler, or control device.

As shown below, emissions controls for these sources can be extremely cost effective, because capture systems such as VRUs and "route-to-process" approaches such as directing vapors that would be vented to a heater or boiler actually increase revenue for operators. The commonsense approach of routing vented vapors from multiple sources to a capture or route-to-process system will make this methods of reducing emissions even more cost-effective, so DEP should account for all of these sources in determining appropriate standards. We note that all sources should be considered both at new facilities (i.e., new wellpads and new compressor stations) and at facilities that are modified by the addition of new equipment.

Should DEP not take this approach, at bare minimum, DEP must define a storage vessel so that two or more physical tanks that are manifolded together to act as a single storage vessel are treated as a single unit for the purposes of determining applicability. Otherwise, operators will be incentivized to install multiple smaller tanks on a site to avoid having a single tank which exceeds the emissions threshold and is subject to the emissions standard. Of course, actual emissions in that case would be as high as from a single uncontrolled tank.

2. 200 Ton per Year Methane Threshold

The threshold for control of methane emissions for new and modified tanks, dehydrators, and pigging operations in the proposed GP-5 and GP-5A – 200 tpy of methane – is considerably too high. DEP cannot consider 200 tpy of methane a *de minimis* quantity. Because of the potency of methane, EPA considers 200 tons of methane to have as much potential to damage the climate as the emissions of 10,000 tons of carbon dioxide – which is as much as is generated by over 950 cars in a year (almost 11 million miles driven).[60] Furthermore, it is not appropriate to calculate a *de minimis* amount of a pollutant by considering merely the ratio of emission rates of that pollutant and another pollutant from the same source.

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[60] EPA. "Greenhouse Gas Equivalencies Calculator." Available at: https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator.

In 2014, EPA economists calculated and published estimates of the damage done to society by emissions of methane, known as the "social cost of methane" (abbreviated as "SC-CH_4"). This analysis represents the most scientifically rigorous study yet conducted on the incremental costs to society from methane emissions. Its estimates of damage vary from $490 - $3,000 per metric ton of emitted methane, depending on the discount rate used and other parameters (values discussed here are for emissions in 2015; emissions in 2017 and future years will cause somewhat more damage). These values convert to $440 – $2,700 per short ton of methane. Studies incorporating the SC-CH_4 have generally relied on the average damage values and a 3% discount rate, referred to as the "3% Average" value in tables, etc., as a central estimate of the damage caused by methane. This value is $1,100 per metric ton of methane, or $1,000 per short ton.[61] Thus, using the best estimate available for the damage to society from methane emissions, 200 tons of methane causes about $200,000 in damage. Again, this cannot be considered *de minimis*.

Because Pennsylvania has significant "dry" unconventional gas resources, we are concerned that there will be sources which emit very little VOCs, and therefore do not exceed the 2.7 tpy VOC threshold, but emit a large amount of methane which could be cost-effectively – even profitably – controlled. Of particular concern are dehydrators and produced water tanks for dry gas resources. If natural gas is 100% methane, 200 short tons is about 9,300 Mcf of natural gas (this is a lower limit, as 200 tons would correspond to larger volumes of natural gas with less than 100% methane content). At a low value for natural gas of $2.00 per Mcf, this gas has a value of over $18,000. As we show below, such large emissions from tanks can be recovered *at profit*.

However, with the 200 tpy threshold that DEP has proposed, we expect that either a very small number of tanks, or none at all, would be subject to the standard. We analyzed DEP's 2015 emissions data from unconventional production facilities and compressor stations. Out of 3,446 distinct facilities that reported tank emissions, only three facilities (0.087%) reported more than 200 tpy of methane emissions.[62] Since the data does not indicate how many tanks are present at each facility – it simply reports the total tank emissions from a facility – it is not apparent that any storage tank in Pennsylvania will trip the 200 tpy methane threshold.

In contrast, the California Air Resources Board (CARB) recently finalized a regulation for new and existing tanks in California, requiring control of tanks emitting just 10 metric tons per year of methane.[63] CARB found that control at this level is cost-effective: they calculated that the overall cost of their tank controls, including recordkeeping costs, costs of low-NOx incinerators, and other costs specific to their rule, are $7.81 per ton of avoided CO2eq

[61] See RIA for proposed NSPS Subpart OOOOa (August 2015), at 4-14. Available at: https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-5258.

[62] 2015 DEP Air Emissions Data, *supra* note 1.

[63] CARB Final Regulation Order, available at: https://www.arb.ca.gov/regact/2016/oilandgas2016/oil%20gasfro.pdf, § 95668(a)(6) – (8).

emissions.[64] CARB used a GWP of 72 to convert methane emissions to CO2eq emissions,[65] so $7.81 per ton of CO2eq is equivalent to $562 per avoided metric ton of methane emissions – less than the damage caused by a metric ton of methane emissions (the social cost of methane). CARB based these calculations on cost data from VRUs that EPA obtained from Natural Gas STAR Industry partners. This data showed that a VRU capable of handling 25 Mcf of gas per day (9,125 Mcf/year, or about 195 short tons per year of methane if gas is 100% methane) has an annualized cost (capital + maintenance) of $11,995 per year.[66]

Even with much more conservative data, such as the value of recovered gas or the cost of a VRU, capturing gas at far lower thresholds than DEP's proposed 200 tpy is cost-effective. For example, the Colorado Department of Public Health and Environment (CDPHE) estimated a much higher equipment purchase and installation costs for a VRU than CARB: CDPHE estimates purchase and installation costs $102,802,[67] while CARB estimates these costs at $35,737.[68] Considering annual maintenance costs and annualizing over ten years at a 5% interest rate, the total annual cost for the VRU (capital + operating) according to CDPHE is $22,709 per year.[69] If we assume this high cost for the VRU[70] and a low price of gas of $2 per MCF – well below EIA projections of the price of gas in the near future[71] – the abatement cost for capturing just 22 tpy with a VRU is $960 per short ton of methane (accounting for the increased revenues operators receive from sale of the conserved gas), below the social cost of methane.[72] If we instead use the lower cost figures from CARB, the net abatement cost at the 22 tpy threshold would be considerably lower ($463 per short ton of methane). If we use a higher price of gas, these net abatement costs would be lower. These calculations are also conservative for several other reasons.[73]

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[64] CARB (2016), Economic Analysis for Proposed Oil and Gas Regulation (below, "Economic Analysis,") at page B-27. Available at: https://www.arb.ca.gov/cc/oil-gas/Oil%20and%20Gas%20Appx%20B%20Economic%20Analysis.pdf. (Includes savings from increased revenues due to sale of captured gas, calculated with a price of gas of $3.44 per MCF).

[65] Ibid, at page B-3.

[66] Ibid, at page B-24. Annualized with a 5% interest rate over 10 years (see Ibid, page B-14).

[67] Colorado Department of Public Health and Environment, Cost-Benefit Analysis for Proposed Revisions to Colorado Air Quality Control Commission (AQCC) Regulations No. 3 and 7, February 7, 2014, (below, "CDPHE Cost-Benefit Analysis,") Table 17. https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-7573.

[68] CARB Economic Analysis at B-24.

[69] Note that the annualized costs calculated by CDPHE are lower, because they annualize over 15 years at a 7% interest rate. We use the California parameters (10 years / 5%) here to facilitate comparison.

[70] Note that US EPA's calculation of costs for NSPS Subpart OOOOa is based on the Colorado cost estimates.

[71] Energy Information Administration. "Natural gas prices in 2017 and 2018 are expected to be higher than last year." (January 2017). Available at: https://www.eia.gov/todayinenergy/detail.php?id=29632.

[72] We assume that the gas in this case is 100% methane, (costs per ton would be lower for gas with less than 100% methane).

[73] The approach we take here is to calculate the abatement cost of a tank at the threshold. Tanks with higher emissions will have a lower abatement cost, since their capital and maintenance costs will be very similar to those at the threshold, while the revenues from sale of conserved gas and the abatement tonnage will be larger. If the total cost per ton for all tanks covered by the standard were calculated, it would be lower than the "threshold" value discussed here. Additionally, longer equipment lifetimes, such as the 15 year lifetime Colorado uses, may be appropriate. Also, even dry gas sources usually contain some VOC and other pollutants, and this analysis ignores the benefits of reducing those non-methane pollutants. Finally, a VRU can capture gas from other sources (such as pneumatic pumps) at a facility, which would only improve its cost-effectiveness.

We created a simple spreadsheet to calculate the cost-effectiveness of capturing methane from a storage vessel at various applicability thresholds, which we include as an exhibit to these comments (attached as Exhibit 4). This spreadsheet was used to calculate the costs discussed above, and we invite DEP to use it to reproduce those figures and explore the implications of various parameters (discount rate and equipment lifetime, price of gas, and methane content of gas) on the abatement cost.

These calculations show that even a threshold almost ten times lower than the one proposed by DEP will result in abatement costs below the social cost of methane. DEP must adjust the threshold for control to a more appropriate value, given the harm caused by methane emissions.

US EPA and other states have found abatement costs for methane of these magnitudes to be reasonable. Colorado's 2014 rules for oil and gas included controls for the mixture of methane and ethane with abatement costs of over $1,000 per short ton.[74] CARB estimated that their entire rule would have a methane abatement cost of over $1,200 per short ton of methane, and that LDAR provisions of their rule would have methane abatement costs of over $1,500 per short ton of methane.[75] Both the social cost of methane, which is based on peer-reviewed studies assessing the damage to human society from climate change, and precedent from other jurisdictions demonstrate that abatement costs in this range are reasonable.

DEP should consider CARB's threshold of 10 metric tons, and other appropriate thresholds, and set a threshold for control of methane from tanks, dehydrators, and pigging operations far lower than 200 tpy.

III. Vented Sources

We support DEP's inclusion of standards for a variety of types of equipment that vent methane and other air pollutant gases in the draft GP-5 and GP-5A. These include the standards for glycol dehydration units, reciprocating compressors, storage vessels, pumps, pigging operations, and, at compressor stations and processing plants, centrifugal compressors.

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[74] CDPHE estimated that leak detection and repair for well sites would have an abatement cost of up to $1,476 per short ton of methane and ethane, while VRUs for storage tanks would have an abatement cost of $1,168 per short ton of methane and ethane. See CDPHE Cost-Benefit Analysis, table 35 and page 17.

[75] CARB estimates that the entire rule has a cost of $1,368 per metric ton of abated methane, and that the LDAR portions of the rule have a cost of $1,697 per metric ton of abated methane. See CARB Economic Analysis, Table B-2.

1. Whenever feasible, DEP should require operators to capture rather than combust gas that would otherwise be vented.

In general, the standards in the draft permits require operators to either capture gas, so it can be used beneficially on-site or sold, or control the pollution from the gas, as with a combustion device. While controlling pollutants with combustion devices is far better than uncontrolled venting of methane and other pollutants, the control devices still emit significant pollution, and combusting methane and other components of natural gas in this way wastes the energy content of these hydrocarbons.

DEP should modify the approach taken in the general permits to clearly require operators to capture natural gas, as with a vapor recovery unit (VRU), or use it on-site, whenever feasible. Operators should only use a combustion device to control hydrocarbons from these sources after demonstrating that capture or use is not feasible. There are examples of regulations in place from several jurisdictions / agencies that are structured in this way and DEP has, in fact, followed this approach for well completions:

- First, proposed GP-5A would require operators to capture gas during well completions of unconventional wells, rather than flare it, unless it is technically infeasible to capture the gas and deliver it to a pipeline, utilize it on site, or re-inject it, in which case operators must combust the gas (with some exceptions) (Draft GP-5A, Section D, Condition 1(c)). DEP's approach here follows that used by US EPA in NSPS Subparts OOOO/OOOOa.

- Second, the Bureau of Land Management's Venting and Flaring rule for Production Activities on onshore Federal and Indian Leases requires that operators capture emissions from two sources, pneumatic pumps and storage vessels, unless it is "technically infeasible or unduly costly" to do so. In instances of infeasibility or undue cost, operators must combust the gas (with some exceptions). (43 CFR § 3179.202(c)-(d); § 3179.203(c)(1)-(2)).

- Third, the California Air Resources Board's recent regulations on oil and gas operations require gas from tanks, wet seal centrifugal compressors, and pneumatic pumps to be captured and directed into a pipeline, used on site, or re-injected, unless there is no equipment at the site to do so (that is, no pipeline, fuel gas system, or re-injection well), in which case operators must combust the gas. (CARB Final Regulation Order, § 95668(a)(6)-(7); § 95668(c)(2)-(3); § 95668(e)(5); § 95668(f)(5)(A).)

We urge DEP to modify the proposed standards in order to require capture wherever feasible. In addition to reducing pollution from combustion of gas, capture technologies have several advantages for operators, such as increased revenue from the sale of recovered gas and avoided costs of compliance with performance standards for control devices that utilize combustion. However, operators may tend to utilize combustion devices, an approach they are familiar with, despite the advantages of capture technologies. DEP standards that require capture whenever feasible will counter this tendency, for gas from vented sources such as reciprocating and centrifugal compressors, storage vessels, pneumatic pumps, and pigging operations.

2. GP text should be modified to clarify that capture technologies are permissible.

In some cases the language of the draft GPs could actually be read to suggest that the permits limit options for, or do not allow, capture of gas; DEP should, at bare minimum, correct the language so that all operators understand that capture of gas is allowed. For example, in draft GP-5A, Sections F, M, and O clearly allow the use of VRUs to control emissions from glycol dehydrators, pumps, and pigging operations, respectively. However, these sections do not clearly allow routing captured gas to boilers or fuel gas. For example, the dehydrator standards require operators to utilize a "condenser, enclosed flare, thermal oxidizer, vapor recovery unit, or other air cleaning device approved by the Department that meets the applicable requirements in Section N."[76] While Section N(1)(f) does mention routing emissions to a "process," this is in the context of ensuring that closed vent systems, including those designed to route emissions to a control device such as an enclosed flare, operate correctly. Many operators may not realize that this is intended to allow them to route emissions to a boiler or use them for fuel gas, which is preferable to destroying emissions in a combustor without recovering any useful energy from the hydrocarbons.

DEP should also clarify GP-5 and GP-5A to clarify that VRUs are allowed for reciprocating compressors (Section H, Condition 1(a)(ii)), storage vessels (e.g., Section I, Condition 1(c)(i)(A), with similar language in other paragraphs of Section I, Condition 1), or for centrifugal compressors in draft GP-5 (Section H, Condition 1(a)(i)(A) and (b)(i)(A)). For example, for storage vessels, the Compliance Requirement directs operators to "route all vapor through a closed vent system to a control device that [reduces air pollutants by a certain amount] by meeting the applicable control, cover, and closed vent system requirements of Section N Condition 1(a) through (f) or any alternative method approved by the Department…" Draft GP-5A, Section I, Condition 1(c)(i)(A). While, as described above, Section N(1)(f) does mention routing emissions to a "process," given the context and structure of Section N we are concerned that many operators will not realize the VRUs are allowed for these equipment types.

Our understanding is that DEP intends to allow operators to capture or utilize gas from these sources, rather than only allow operators to combust the gas. As described above, DEP should modify the proposed standards to require operators to use capture technologies, rather than combustion approaches, whenever feasible. At a minimum, DEP should modify the language of draft GP-5 and GP-5A to ensure that routing vapors to a VRU, boiler, or fuel line is clearly allowed for all sources.

[76] Draft GP-5A Section F, Condition 1(c)(i)(A).

3. DEP must ensure that only technologies that effectively control methane are used to control vented sources.

DEP should not allow operators to use control technologies based on condensers or carbon absorption, referred to as "Vapor recovery devices" in § N(1)(b), for any type of equipment, because these technologies will not control methane emissions by any significant amount. For this issue, we refer to comments filed by Clean Air Task Force to the United States Environmental Protection Agency on December 4, 2015, on the proposed NSPS Subpart OOOOa that document the ineffectiveness of these technologies to methane; these comments are attached as Exhibit 5 to this document.

4. Centrifugal compressors

DEP should ensure that gas that would be vented from wet-seal centrifugal compressors is captured (not combusted), whether the compressor is located at a well production facility or at a compressor station. Inexpensive systems can readily be installed on wet-seal compressors to capture vented gas from the seal oil degassing system and route the captured gas to the intake of the compressor – these systems pay for themselves in months.[77] DEP should ensure that capture of gas from these systems, rather than combustion, is used whenever feasible.

Draft GP-5A does not include provisions for centrifugal compressors. We are concerned that operators who install centrifugal compressors at sites with natural gas or oil wells may consider those facilities to be natural gas well operations as opposed to natural gas compression stations, and therefore assume that the centrifugal compressor provisions of GP-5 do not apply to the facilities. This is not a theoretical concern: analysis of data submitted to EPA's Greenhouse Gas Reporting Program has shown that some centrifugal compressors with wet seals are located at well production facilities.[78] Furthermore, NSPS Subparts OOOO and OOOOa do not apply any standards to centrifugal compressors located at well production facilities.[79] Emissions from these wet-seal compressors should be captured, instead of emitted, just as should be done for compressors at compressor stations. If DEP does not wish to add centrifugal compressor provisions to GP-5A, then the Department should note that facilities with wet seal centrifugal compressors are not eligible for GP-5A if they vent the wet seal degassing emissions from those compressors.

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[77] BP reported that systems to capture emissions from wet seals on centrifugal compressors can have payback times of a month or less. See Reid Smith and Kevin Ritz (2014), "Centrifugal Compressor Wet Seals Seal Oil De-gassing & Control" (presentation at Natural Gas Star Annual Implementation Workshop, San Antonio Texas), at 21. Available at: https://www.epa.gov/sites/production/files/2016-04/documents/experiences_wet_seal.pdf.

[78] *See* Clean Air Task Force et al., Comments on "Oil and Natural Gas Sector: Emission Standards for New and Modified Sources (Proposed NSPS Subpart OOOOa)," p. 103. Available at: http://www.catf.us/resources/filings/oil_and_gas/eNGO_methane_comments.pdf.

[79] *See* 40 CFR 60.5365(b) and 60.5365a(b), both of which state that "A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart."

IV. Pneumatic Controllers and Pumps

<u>DEP Must Address Emissions from Both Intermittent-Bleed and Continuous-Bleed Pneumatic Controllers</u>

1. Pneumatic controllers are a very large source of methane and other air pollutant emissions

We know that emissions from continuous-bleed pneumatic controllers, even those designed to be "low-bleed," can be substantial. Draft GP-5 and GP-5A require new controllers to be "low-bleed," in line with EPA rules, if located at a site that does not have access to grid electricity. Although low-bleed controllers are superior to high-bleed controllers, they often do not function as designed or otherwise emit more than designed: a significant number of controllers designated as low-bleed by operators or manufacturers have been observed to actually emit above the 6 scfh threshold.[80] Improperly functioning devices may result in substantial emissions.

We also know that emissions from intermittent-bleed pneumatic controllers, specifically in Pennsylvania, are substantial. Intermittent-bleed pneumatic controllers are a major source of harmful air pollution that are not subject to any federal or Pennsylvania emissions standards. There is no precise data for the exact number of these devices in Pennsylvania. However, based on data reported to EPA's Greenhouse Gas Reporting Program (GHGRP), we estimate that, in 2015, there were 28,000 intermittent-bleed controllers with emissions of over 32,000 tons of methane in the state.[81]

These controllers frequently have high emissions for two reasons. First, they are designed to vent natural gas while actuating, and some controllers actuate very frequently. For example, of the 377 pneumatic controllers (both continuous-bleed and intermittent-bleed) studied by Allen et al. (2014)[82], 24 actuated at least 10 times during the sampling period, which was typically 15 minutes. Four actuated over 50 times while being sampled.[83] These devices can

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[80] *See, e.g.*, Clean Air Task Force et al., *Comments on Oil and Natural Gas Sector: Emission Standards for New and Modified Sources*, Dkt. No. EPA-HQ-OAR-2010-0505 at 34–35 (Dec. 4, 2015), https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-7062.

[81] Subpart W, https://oaspub.epa.gov/enviro/AD_HOC_TABLE_COLUMN_SELECT_V2.retrieval_list.
EF_W_NGPNEUMATIC_DEV_UNITS: : This table lists the number of pneumatic controllers reported by each company in each basin, and specifies whether the controllers are high-, intermittent-, or low-bleed.
EF_W_INTRODUCTION_SUMM: This table lists the number of wells reported by each company in each sub-basin county. This information shows how many wells in the Appalachian Basin are located in Pennsylvania vs. other states. Count and emissions from intermittent-bleed controllers in Pennsylvania calculated by multiplying count and emissions at each facility in Basin 160/160A by the percent of wells in that facility that are located in Pennsylvania.

[82] David T. Allen et al., *Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers*, 49 Envtl. Sci. & Tech. 633, 637 (2014), http://pubs.acs.org/doi/pdf/10.1021/es5040156.

[83] *See* David T. Allen, et al., *Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers – Supporting Information* 10–19 & tbl. S4-1 (2014), http://pubs.acs.org/doi/suppl/10.1021/es5040156.

emit at high levels—five of the 40 highest emitting devices in the Allen et al. sample were intermittent-bleed devices that the researchers assessed to be operating properly.[84] These controllers emitted up to 40 scfh of whole gas during the sampling interval.[85] Devices with certain specific functions, such as level controllers on separators, are likely to actuate frequently. This can arise, for example, if operators undersize separators at a wellpad with high liquids production. Since unconventional shale gas wells can produce large amounts of water in initial years, this is a relevant concern for Pennsylvania.

Second, as described above (see Section I.4), intermittent-bleed pneumatic controllers frequently do not operate as designed and emit natural gas continuously, not just when actuating. This creates an additional stream of emissions beyond that resulting from normal operations. For example, Allen et al. concluded that, among controllers with the highest emissions rate, many suffered from easily reparable issues, and "many of the devices in the high emitting group were behaving in a manner inconsistent with the manufacturer's design."[86] A City of Fort Worth study that examined emissions from 489 intermittent-bleed devices using infrared cameras and other methods found that many controllers were emitting constantly and at very high rates, even though they were being used to operate separator dump valves and were not designed to emit between actuations.[87] A study in British Columbia also noted a potential for maintenance issues causing abnormally high bleed rates.[88] Finally, data compiled by inspectors from Boulder County, Colorado show that improperly functioning pneumatic controllers constitute a significant portion of the leaks they observe during their inspections (attached here as Exhibit 6).[89]

2. Cost-effective technologies are available to eliminate emissions from continuous-bleed and intermittent-bleed pneumatic controllers and pneumatic pumps

An August 2016 study by Carbon Limits shows that cost-effective zero-bleed options exist for both new and existing pneumatic devices, even where grid power is not being used at the site, and these options have been proven to work robustly in upstream oil and gas operations.[90] Specifically, Carbon Limits performed a comprehensive literature review and

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[84] *Id.* at 81–120. Temporal profiles of emissions from the 40 highest-emitting controllers sampled in the study are shown. Controllers LB01-PC01, LB07-PC01, LB04-PC01, LB06-PC05, and LB04-PC03—five of the 40 highest emitting controllers—are clearly intermittent devices which were assessed to be "operating as expected." *Id.* at 96, 100, 105, 108, 114.

[85] Controller LB01-PC01 emitted 40.2 scfh whole gas; the range for the controllers listed in the previous footnote was 19.1—40.2 scfh. *Id.* at 96.

[86] Allen et al. 2014, *supra* note 9, at 639.

[87] E. Research Grp., Inc. & Sage Envtl. Consulting, LP, *City of Fort Worth Natural Gas Air Quality Study* at 3-100 (July 13, 2011), http://fortworthtexas.gov/uploadedFiles/Gas_Wells/AirQualityStudy_final.pdf ("Under normal operation a pneumatic valve controller is designed to release a small amount of natural gas to the atmosphere during each unloading event. Due to contaminants in the natural gas stream, however, these controllers eventually fail (often within six months of installation) and begin leaking natural gas continually.").

[88] Prasino Grp., *Determining Bleed Rates for Pneumatic Devices in British Columbia* 19 (Dec. 18, 2013), http://www.bcogris.ca/sites/default/files/ei-2014-01-final-report20140131.pdf.

[89] *See* Exhibit 6. Boulder Cty. Pub. Health, *Summary of Findings During Infrared Camera Inspections* (Mar. 13, 2017).

[90] Carbon Limits, *Zero Emission Technologies for Pneumatic Controllers in the USA: Applicability and Cost Effectiveness* (Aug. 1, 2016), http://catf.us/resources/publications/files/Zero_Emitting_Pneumatic_Alternatives.pdf (Carbon Limits).

conducted 17 in-depth interviews with technology providers, as well as small and large oil and gas companies; Carbon Limits gathered up-to-date information on field experience with the implementation of zero-emission technologies, their applicability, and their costs.[91] The zero-emission options Carbon Limits examined included:

- Using compressed "instrument air" instead of natural gas to drive pneumatic controllers.

- Using electronic control systems and electric valve actuators instead of pneumatic controllers and valve actuators for valve automation. This approach can be used both at sites where electricity is already available and at sites without grid power by installing solar-powered systems.

- Pneumatic controllers that do not release gas to the atmosphere, but rather release gas to a pressurized gas line. These are typically referred to as "bleed-to-pressure" or "integral" controllers.

- Capturing gas released from pneumatic controllers using vapor recovery units, or routing gas that would otherwise have been emitted to fuel lines on site.[92]

Carbon Limits found that mature, reliable, and low-cost technologies are available in almost all situations to replace venting pneumatic equipment.[93] The study demonstrates that for almost any configuration of oil and gas facilities, at least one of these technologies is an available, feasible, and low-cost means of methane abatement as compared to unmitigated natural gas-driven pneumatic controllers. In particular, both solar- and grid-powered electronic controllers and instrument air technology are in wide use today and readily available in the market. Carbon Limits accordingly concluded that "[o]verall . . . zero-emission solutions are available today and are cost-effective to implement in nearly every situation."[94]

The Carbon Limits study includes a detailed analysis of the economics of electronic controllers and instrument air. Carbon Limits used the capital and operating costs of these systems and traditional pneumatic controllers,[95] together with highly conservative estimates of

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[91] *Id.* at 7.

[92] *Id.* at 12–13. One additional last resort option that Carbon Limits did not examine is routing gas that would be vented from controllers to a control device—an incinerator or flare. Of course, it should be noted that the zero-emission options discussed by Carbon Limits are always superior to incineration or flaring where any one of them is feasible, and incineration or flaring should only be used as an emission control method when no other options (apart from venting) are available.

[93] *Id.* at 12. Carbon Limits reports that instrument air is applicable at larger sites (roughly 20 or more controllers on site) when power is available from the grid or from an on-site generator. *See id.* at 23. It also reports that electric controllers are applicable at sites of all sizes if power is available, and, in combination with solar power, applicable at smaller sites (20 or fewer controllers) when power is not otherwise available. *See id.* However, Carbon Limits reports that there is no technical barrier to the use of electric controllers with solar panels at larger sites; there is simply little known precedent of this type of installation. *See id*. at 16.

[94] *Id.* at 4.

[95] Costs were derived from interviews with oil and gas producers, system and component suppliers, and online quotes from component suppliers.

emissions from gas-driven pneumatic controllers[96] and other parameters, to calculate the net cost of these systems per metric ton of avoided methane pollution, using a net present value formulation. The study considers the full cost of these systems—for example, for electric controllers at sites without electricity available, the costs considered by the study include solar panels, batteries, and control panels, in addition to installation costs and other outlays. Notably, the conservative emissions factors used in the Carbon Limits model are probably too low in many cases, given the pattern noted above of substantial emissions from improperly operating controllers.

An operator using either electronic controllers or instrument air to replace traditional gas-driven pneumatic controllers will generally replace all controllers (*both continuous-bleed and intermittent bleed*) and pneumatic pumps at a site, since all new controllers will use certain common equipment (such as solar panels and batteries for off-grid electronic controllers, or air compressors and tanks for instrument air-driven controllers). Typically, the cost of the common equipment is a large portion of total system cost, so the cost-effectiveness of the system will vary with the number of controllers (and pumps) at a site, in addition to other parameters.

Carbon Limits found that using instrument air and/or electric controllers as opposed to using gas-driven pneumatic equipment is cost-effective for the vast majority of site configurations. In these cases, the costs were lower than the social cost of methane and the costs that other states have considered appropriate for methane abatement (see Section II of this document above).

To illustrate this, and allow readers to explore the cost-effectiveness of these non-emitting technologies, Carbon Limits created a spreadsheet tool that calculates the costs at a site with parameters input by the user. The user-controlled parameters include:

- the number of controllers of various types at each site;
- emissions factors for those controllers;
- whether the site
    - is new or has existing gas-driven controllers being considered for retrofit,
    - has electric power available already, and
    - has dry gas or wet gas;
- the value of the gas conserved by switching from gas-driven pneumatics to zero-emitting options to the operator;
- costs of various types of equipment; and
- essentially all other parameters, from discount rate to the number of days of energy storage required for solar systems.

The Carbon Limits spreadsheet is provided as an exhibit to these comments (Exhibit 7).[97] Below we describe some of the results that can be readily calculated using this tool, using conservative parameters.[98]

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[96] Carbon Limits, *supra* note 90, at 21–22.

[97] Carbon Limits. Zero emission technologies for pneumatic controllers in the USA. *See* Exhibit 7.

[98] In addition to the parameters mentioned in the text, we assumed that conserved gas has a value of $2/MCF.

Based on the analysis of data reported by Pennsylvania natural gas producers to EPA's GHGRP, we calculate that on average there are 0.91 intermittent-bleed pneumatic controllers at each well and 0.17 continuous-bleed pneumatics per well.[99] Further, CATF analyzed Pennsylvania unconventional well locations and calculated that the median shale well drilled in 2016 in Pennsylvania is on a pad with 5 other wells (including all wells drilled by the end of the year).[100] Thus, a typical new unconventional well is on a six-well pad with one continuous-bleed pneumatic controller and five intermittent-bleed pneumatic controllers.

Using these controller counts, a *new* dry-gas site with no power available would have a cost of $2,076 per short ton of VOC abatement and $557 per metric ton of methane abatement. This assumes that new continuous-bleed controllers only emit 1.39 standard cubic feet (scf) of natural gas per hour (the EPA emission factor for low-bleed controllers), despite the evidence that even low-bleed controllers often emit more than six scfh (see previous section).[101] Net costs are lower for wet-gas sites because, when wet gas is used to operate pneumatic controllers, maintenance problems can arise, which are eliminated by switching to electric controllers or air-driven controllers. Counterintuitively, costs are lower for existing sites, because older controllers are higher emitting (especially continuous-bleed controllers, which may be high-bleed if they predate NSPS Subpart OOOO). An existing dry-gas facility with the same number of pneumatic controllers would have an abatement cost of $781 per short ton of VOC abatement and $272 per metric ton of methane abatement.[102]

These cost estimate were made using conservative assumptions. Costs will be even lower for large sites with many controllers, sites that have pneumatic pumps, and at sites that have electrical power available. Our calculations are also conservative because they consider only the cost of abating a single pollutant at a time (methane ***or*** VOCs) even though utilizing instrument air or electric controllers would simultaneously reduce emissions of both pollutants. A multi-pollutant approach would demonstrate lower costs per ton of either pollutant reduced. Finally, as can be seen in Exhibit 3, Carbon Limits' finding is based on conservative assumptions about other parameters, such as equipment costs.

3. Other approaches are available to reduce emissions from pneumatic controllers

The Draft GPs require that new pneumatic controllers at sites without access to grid electricity be low emitting (less than or equal to six scf per hour). It is our understanding that this applies only to continuous-bleed controllers. As we describe above, there are cost-effective

[99] Pneumatic and well counts in Pennsylvania described in fn 2.
[100] Based on the location of unconventional wells downloaded from PA DEP, http://www.depreportingservices.state.pa.us/ReportServer/Pages/ReportViewer.aspx?%2fOil_Gas%2fOil_Gas_Well_Production. Wells within 40 meters of one another were assumed to be on same pad; all groupings with a maximum distance between an individual well and the center of the pad over 15 meters were visually checked to ensure that the grouping was indeed a single wellpad. Statistics for the number of wells on a pad, including wells drilled before 2016 and through the end of 2016, were compiled for all unconventional wells drilled in 2016. The median value, including the new well, is 6 wells per pad.
[101] Other assumptions: $2/mcf gas, and emissions of 4.4 scf per hour for intermittent controllers.
[102] Assuming $2/mcf gas, and emissions factors of 14.4 scfh for continuous-bleed controllers and 4.4 scfh for intermittent controllers.

zero-emitting options that can avoid all emissions from both continuous- and intermittent-bleed controllers. However, even if DEP does not choose to require operators to utilize these options, there are other options that would reduce emissions.

First, the emissions standard for continuous-bleed controllers (less than or equal to six scf per hour) can be applied to intermittent-bleed controllers. Since 2010, Wyoming has required that controllers, including intermittent-bleed controllers, at new and modified facilities statewide bleed less than six scf per hour, or operators must route the emissions from the controller to a process.[103] A more recent regulation required operators of *existing* pneumatic controllers in the Upper Green River Basin to replace any pneumatic controllers, again including intermittent-bleed controllers, emitting over 6 scfh or route emissions from those controllers to a process by January 1, 2017.[104]

Second, many natural gas facilities have electricity available for lighting, systems control, and other purposes. This may be generated on site, as opposed to a utilizing a grid connection. Modern electric controllers use relatively small amounts of electricity (less than needed to drive an instrument air compressor, for example – this is why solar-powered electric controller systems are feasible). Standards requiring non-emitting solutions at these sites would be very low cost, since the availability of electricity drives the cost of electric controllers down considerably (the Carbon Limits spreadsheet tool[105] allows users to calculate the abatement cost of methane at sites with – and without – electric power available).

Finally, as described above in Section I.4, LDAR inspections can be used to minimize emissions from both intermittent-bleed and continuous-bleed controllers located at facilities already subject to LDAR requirements. On March 23, 2017, CARB finalized standards regulating greenhouse gas emissions from oil and gas operations, which require inspection of intermittent-bleed pneumatic controllers for continuous emissions during LDAR inspections.[106] These standards require quarterly LDAR inspections of oil and gas wellpads and compressor stations,[107] and require checking all intermittent-bleed pneumatic controllers for improper continuous emissions during each inspection.[108] Controllers improperly emitting between actuation must be repaired. In addition, operators of any existing continuous-bleed controller (all

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[103] Wyo. Dep't of Envtl. Qual., *Oil and Gas Production Facilities: Permitting Guidance* at Ch. 6, § 2 (2010) (WDEQ Permitting Guidance) (Exhibit 7) (stating that gas operated "pneumatic controllers shall be low [under 6 scfh] or no-bleed controllers or the controller discharge streams shall be routed into a closed loop system."). Wyoming applies these provisions to both continuous-bleed and intermittent-bleed pneumatic controllers. *See* Email from Mark Smith, Wyo. Dep't of Envtl. Qual., to David McCabe, CATF (Sept. 22, 2014) (Exhibit 8).

[104] Wyo. Code R. Envtl. Air Qual. Ch. 8 § 6(f); *see also* Wyo. Dep't of Envtl. Qual., *Comment Response Concerning the Proposed Wyoming Air Quality Standards and Regulations, Chapter 8, Section 6, Nonattainment Area Regulations* at 10 (May 14, 2015) (Exhibit 9) ("The regulation does not limit operators from using intermittent or continuous bleed controllers as long as the bleed rate is below the 6 standard cubic feet per hour (scfh) threshold.").

[105] *See* Exhibit 7.

[106] Cal. Air Res. Bd., *CARB Approves Rule for Monitoring and Repairing Methane Leaks from Oil and Gas Facilities* (Mar. 23, 2017), www.arb.ca.gov/newsrel/newsrelease.php?id=907.

[107] Cal. Code Regs. tit. 17, § 95669(a), (g), www.arb.ca.gov/regact/2016/oilandgas2016/oilgasfro.pdf.

[108] *Id.* § 95668(e)(3).

of which must be low-bleed) must directly measure emissions from those controllers on an annual basis, and repair or replace any controller emitting more than six scf per hour.[109]

The incremental cost of checking intermittent-bleed controllers for continuous emissions during an LDAR inspection is very low, since the inspector is already on site – in most cases the device will not be actuating and the incremental cost of inspecting one more component is very small. Although this approach would not address a major source of emissions—devices that simply have high emissions when functioning properly—it would reduce emissions from improperly functioning intermittent-bleed controllers with minimal additional burdens on operators that are already inspecting facilities where such devices are located. As noted above, there are a number of reports that confirm this is a frequent problem.

Direct measurement of emissions from continuous-bleed controllers during LDAR inspections has a small incremental cost – it is more time consuming than checking intermittent-bleed controllers between actuations and it may require the use of instruments that the inspectors are not routinely using. Nevertheless, such measurements are commonly performed during LDAR inspection. GreenPath Energy, a firm providing LDAR inspection services to oil and gas producers in the US and Canada, estimates that the incremental cost of directly measuring emissions from a pneumatic controller is $36.43 per controller (attached here as Exhibit 8).[110] This estimate accounts for both the extra time required on site, and the instrument used to measure emissions from the controller. This cost is a very conservative estimate for continuous-bleed controllers, since GreenPath estimated the cost based on measuring emissions from an actuating controller, which requires measurement for about 15 minutes. As GreenPath notes, emissions from pressure controllers, transducers, and temperature controllers (i.e., continuous-bleed controllers) can be measured in as little as 5 minutes.[111]

4. Suggested Approach

Based on the availability of cost-effective means to eliminate or reduce emissions from intermittent-bleed controllers, we urge DEP to consider the following options:

- DEP should require that all new controllers utilize zero-emitting approaches, such as electric controllers, instrument air, or the other approaches discussed above. These technologies and approaches are cost-effective, and as described above, there are a number of zero-emitting options to suit the varying needs of individual operators. Even when a site is not connected to the grid, electronic controllers are cost-effective because it is inexpensive to generate electricity on-site with technologies like solar panels, particularly when the costs of electricity generation are spread across a large number of controllers at a single site. As described above, unconventional wells being drilled today are on large pads with multiple wells and a number of pneumatic controllers, making this approach very cost-effective.

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[109] *Id.* § 95668(e)(2)(A).
[110] GreenPath Energy (2017), Incremental costs for direct measurement of pneumatic device emission rates during Leak Detection and Repair Inspections, attached as Exhibit 8.
[111] *Id.*, p. 2.

Some exceptional circumstances may exist. For example, occasionally operators may drill wells on a single well pad, with no plans for more wells. (However, this is rare: of the 502 shale wells spudded in the Commonwealth in 2016, only three were on single well pads at the end of the year. It is entirely possible that operators plan to drill more wells on those three pads, or perhaps have already done so.) Operators who have an unusal circumstance that makes every zero-emitting option infeasible or extraordinarily expensive always have the option of obtaining a site-specific permit. If DEP feels this will happen more frequently, an infeasibility exception could be added to the GP.

However, the rare exceptional circumstance should not be used to justify allowing broad use of an outdated technology which, in the vast majority of cases, can be replaced with a non-emitting technology at very low cost.

- As described below (see Section VI), it is important that DEP require operators who modify a facility by constructing a new well at the site or adding compression bring other equipment at the site into compliance with the new source standards under GP-5 and GP-5A, rather than just requiring LDAR at the facility. Pneumatic controllers are a critical example of this. GP-5 and GP-5A should require operators of sites which are modified in these ways to replace pneumatic controllers (and pumps) that vent to the atmosphere, or to route emissions from these devices to a process or capture. Operators can usually do this by converting the site to instrument air. This is appropriate because in general, zero-emitting solutions for pneumatic controllers and pumps replace all of the venting pneumatic equipment at a site. Again, while it may be appropriate for DEP to consider exceptions at the smallest facilities, the large facility size (median 6-well pad for new shale wells) in Pennsylvania suggests that this would be very rare.

- At a minimum, DEP must ensure that emissions from new controllers and existing controllers at modified sites be minimized in the following common-sense, low-cost ways:
    - DEP should include standards for emissions from intermittent-bleed pneumatic controllers, in line with Wyoming's standards.

    - All pneumatic controllers should be subject to LDAR requirements, to ensure that intermittent-bleed devices do not emit continuously, that continuous-bleed devices do not vent excessively, and that all controllers and do not leak from other points on the controller aside from the vent port. The controllers should be inspected at any facility already subject to LDAR. Although this option will only capture the portion of emissions caused by improperly functioning devices, it will reduce emissions significantly.

    - DEP should require that no gas-driven pneumatic controller (whether intermittent or continuous) is used at any new site with power available, whether the power is from the grid or generated on site. The language in the draft GPs restricts this requirement to sites with grid power (with the exception of gas processing plants). This may have been appropriate at a time when instrument air was the main alternative to gas-driven controllers, and the industry only considered large compressors to be reliable enough for oil and gas applications. This approach required considerable power. Electric controllers and newer, smaller air compressors require smaller amounts of electricity and are generally appropriate for facilities that already have sources of power on-site (for lighting, SCADA systems or control systems for emissions control devices, etc.).

DEP Should Also Include Protective Standards For Pneumatic Pumps

We support the inclusion of standards for pneumatic pumps in proposed GP-5 and GP-5A. However, DEP should go further. At sites with electricity available, including electricity generated on-site, and at sites with pneumatic controllers, emissions from pneumatic pumps can be eliminated with the same strategies as used for pneumatic controllers: routing emissions to capture, a process, or control; substitution with an electric pump; or (in most cases) conversion of the pump to instrument air (the final option is not feasible for pneumatic glycol assist pumps used on dehydrators). Including conversion of pneumatic pumps to these options makes it more cost-effective to eliminate emissions from pneumatic equipment at a site.

DEP should require that operators install non-emitting options instead of vented pneumatic pumps at all sites with electricity available and whenever electric or instrument air controllers are appropriate.

V. Compressor Venting / Blowdowns

Compressors must periodically be taken off-line for maintenance, operational stand-by, or emergency shutdown testing; in the process, methane may be released to the atmosphere from a number of sources. In particular, when compressor units are shut down, the high-pressure gas remaining within the compressors and associated piping between isolation valves is typically vented to the atmosphere or to a flare. This process, known as a "blowdown," can produce significant methane emissions and is accompanied by loud noise pollution, which can spike up to 90 decibels.

As discussed above, draft GP-5A establishes effective standards to control emissions from wellbore liquids unloading operations, also known as well blowdowns. Unfortunately, no such standards are established in GP-5 for blowdown episodes that take place at natural gas compressor stations. Members of our respective organizations have repeatedly expressed concerns over the significant emissions associated with compressor station blowdowns. While GP-5 imposes some notice, reporting, and recordkeeping requirements for such events, there are no direct standards that require operators to reduce or control emissions of methane or VOCs.[112] This is a significant omission, as the unconventional natural gas industry self-reported to DEP that methane emissions strictly from blowdown vents reached 35,041 tons in 2015 alone.[113] This

[112] *See* draft GP-5, Section A, Condition 10(d)(ii) and (e); Section G, Conditions 2, 3(f), and 4; and Section H, Conditions 2, 3(e), and 4, available at: http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-116053/2700-PM-BAQ0267_GP-5%20.pdf
[113] 2015 DEP Air Emissions Data, *supra* note 1.

comprised over one-quarter (¼) of total methane emissions from all sources in Pennsylvania's natural gas industry that year.

There are multiple cost-effective, technologically feasible means by which operators can responsibly control emissions from blowdowns, and we recommend that DEP strengthen GP-5 by including standards to require such control. EPA's Natural Gas STAR program and participating program partners have found that simple changes in operating practices and in the design of blowdown systems can save money and significantly reduce methane emissions. In particular, we encourage DEP to consider the example from a neighboring state, Ohio.

The Ohio Environmental Protection Agency ("Ohio EPA") recently finalized a series of new general permits that will reduce air pollution from natural gas compressor stations. Among these new permits, General Permit 17.1 establishes that reciprocating compressors (located at compressor stations) shall be designed with a capture and control system designed to control emissions from compressor isolation valves and compressor blowdown vents.[114] Ohio EPA allows operators to meet this requirement in one of two ways: (1) a design that captures one-hundred percent (100%) of gasses from these sources and routes them to a flare designed for ninety-five percent (95%) destruction; or (2) a design that first routes the high pressure gasses to a low pressure line in order to reduce the gas pressure prior to venting to the atmosphere the remaining low pressure gas such that at least ninety percent (90%) of the gasses are recovered. GP 17.1 further requires that operators shall minimize the frequency and size of blowdown events by "conducting routine operation and maintenance activities in a manner consistent with safety and good air pollution control practices."

We urge DEP to follow Ohio's lead and require operators to control compressor blowdown emissions.

VI. Modified Facilities Must Comply with All Provisions, Not Simply LDAR

Draft GP-5A states that the "owner or operator of an existing facility where a new well is drilled or hydraulically fractured, an existing well is hydraulically refractured, or new equipment is installed becomes a modified facility with respect to the fugitive emissions components requirements of Section K . . ."[115] This language implies that a facility, once modified, will thereafter have to comply with only the LDAR requirements of GP-5A, rather than all permit conditions. Given the very low cost to retrofit equipment and sources, this provision appears to be inconsistent with the overarching goal of GP-5A to effectively control emissions from new and modified facilities.

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[114] *See* Ohio EPA General Permit 17.1 Template, Reciprocating Compressor for Natural Gas Service, available at http://epa.ohio.gov/Portals/27/genpermit/GP17.1_F20170221.pdf.

[115] Draft GP-5A, Section C, Condition 1(d), available at: http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-116054/2700-PM-BAQ0268_GP-5A.pdf

To drill and hydraulically fracture a new well at an existing facility will inherently result in a significant increase in emissions from that facility, even if the new equipment is lower emitting as a result of being subject to GP-5 / GP-5A. While requiring LDAR at the entire facility is important, unnecessary vented emissions from outdated equipment will continue under the standards as drafted. In 2014, operators in the Marcellus Shale reported an average well cost of $6.4 million[116]; it is eminently reasonable, therefore, to require the operator of a facility modified by the addition of a well to invest orders of magnitude less capital to ensure that all sources at the facility meet current emission standards following modification. This will help provide peace of mind to residents living near such modified facilities, while reducing emissions of methane, VOC, and other air pollutants in a very cost-effective manner.

For example, if a modified facility became subject to all provisions of GP-5A, the owner or operator of such modified facility would see the costs of retrofitting the facility's high-bleed pneumatic controllers and wet-seal centrifugal compressors paid back within a few years.[117] We urge DEP to follow Wyoming's lead[118] on this point by requiring operators who modify their facilities to comply with all provisions of GP-5A, rather than only the fugitive emissions components requirements. If DEP did not intend for the language in Section C, Condition 1(d) to be interpreted this way, we urge DEP to clarify the text in a manner consistent with the above.

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[116] U.S. Energy Information Administration, "Trends in U.S. Oil and Natural Gas Upstream Costs," (March 2016), available at: https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf

[117] Colorado estimated a payback time of fourteen months for replacement of high-bleed controllers. *See* Colorado Department of Public Health and Environment. "Cost-Benefit Analysis For proposed revisions to Colorado Air Quality Control Commission Regulation Number 3 and Regulation Number 7." (February 2014), at 32. Available at: https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-7573. *See also* EPA Natural Gas STAR. "Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry." (October 2006). https://www.epa.gov/sites/production/files/2016-06/documents/ll_pneumatics.pdf. For centrifugal compressors, BP reports payback for retrofit in a month or less. *See* BP. "Centrifugal Compressor Wet Seals Seal Oil De-gassing & Control." Presentation to Natural Gas Star Annual Workshop; Denver, Colorado (April 2012), at 21. Available at: https://www.epa.gov/sites/production/files/2016-04/documents/smith.pdf. *See also* EPA Natural Gas STAR. "Replacing Wet Seals with Dry Seals in Centrifugal Compressors." (October 2006). Available at: https://www.epa.gov/sites/production/files/2016-06/documents/ll_wetseals.pdf.

[118] Wyo. Dep't of Envtl. Quality, Oil and Gas Production Facilities: Chapter 6 Section 2 Permitting Guidance (June 1997, Revised May 2016) ("WY Permitting Guidance"), 22, available at: http://deq.wyoming.gov/media/attachments/Air%20Quality/New%20Source%20Review/Guidance%20Documents/2013-09_%20AQD_NSR_Oil-and-Gas-Production-Facilities-Chapter-6-Section-2-Permitting-Guidance.pdf

We greatly appreciate the opportunity to comment on these important permit drafts and thank DEP for its leadership on this critical issue.

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