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Honorable Patrick McDonnell
Chairperson, Environmental Quality Board
Secretary of Environmental Protection

Jessica Shirley
Director, DEP Policy Office

Virendra Trivedi
Chief, Division of Permits, Bureau of Air Quality

Jennie Demjanick, Esq.
Assistant Counsel, Bureau of Regulatory Counsel

Charles Boritz
Air Quality Engineering Specialist

Environmental Quality Board
Rachel Carson State Office Building
400 Market Street, 16th Floor
Harrisburg, PA 17101-2301

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Independent Regulatory Review Commission

Re: Proposed Rulemaking – Control of VOC Emissions from Oil and Natural Gas Sources (#7-544)

We submit these comments on behalf of Clean Air Council, Clean Air Task Force, Earthworks, Natural Resources Defense Council, PennFuture, and Sierra Club (together, "Environmental Commenters") on the proposed rulemaking to implement control measures to reduce methane and volatile organic compound (VOC) emissions from existing oil and natural gas sources in Pennsylvania.[1] This proposed rulemaking marks another critical step toward fulfilling Governor Wolf's commitments to reduce methane emissions from the oil and gas sector and to reduce Pennsylvania's greenhouse gas emissions consistent with Executive Order 2019-01.[2] We concur with the Environmental Quality Board (EQB) that this proposed rulemaking is authorized under Section 5(a)(1) of the Air Pollution Control Act[3] (APCA), which grants the EQB the authority to adopt rules and regulations for the prevention, control, reduction and abatement of air pollution in Pennsylvania, and Section 5(a)(8)[4] of the APCA, which grants

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[1] Proposed rulemaking and preamble published in the *Pennsylvania Bulletin*, Vol. 50, No. 21, on May 23, 2020, pages 2633-2664: http://www.pacodeandbulletin.gov/secure/pabulletin/data/vol50/50-21/50-21.pdf
[2] Methane Reduction Strategy, "A Pennsylvania Framework of Actions for Methane Reductions From the Oil and Gas Sector," available at: https://www.dep.pa.gov/Business/Air/Pages/Methane-Reduction-Strategy.aspx; Executive Order 2019-01 – Commonwealth Leadership in Addressing Climate Change and Promoting Energy Conservation and Sustainable Governance, available at: https://www.governor.pa.gov/newsroom/executive-order-2019-01-commonwealth-leadership-in-addressing-climate-change-and-promoting-energy-conservation-and-sustainable-governance/
[3] 35 P.S. §§ 4005(a)(1)
[4] 35 P.S. §§ 4005(a)(8)

the EQB the authority to adopt rules and regulations designed to implement the provisions of the Clean Air Act (CAA).[5]

There is an urgent need to control methane and other harmful pollutants from oil and gas sources in the Commonwealth. A recent Environmental Defense Fund (EDF) analysis using site-level measurement data from Pennsylvania wells reveals that methane emissions from upstream oil and gas sites may be more than fifteen times higher than what operators report to the Department of Environmental Protection (DEP); that equates to more than 1.1 million short tons of annual methane emissions from Pennsylvania well sites.[6] This is double the methane emissions that EDF documented from oil and gas sources just two years ago. The same analysis shows that emissions from Pennsylvania's tens of thousands of conventional wells, which tend to be older and lower-producing than unconventional sources, collectively contribute more than half the total methane pollution from Pennsylvania well sites.

Methane, the primary component of natural gas and a common byproduct of oil production, is a powerful climate pollutant that is 36 times more potent than carbon dioxide on a 100-year timeframe and 87 times more potent on a 20-year timeframe.[7] Approximately one-quarter of the anthropogenic climate change we are experiencing today is attributable to methane.[8] Leaky, outdated, and malfunctioning equipment at oil and gas sites constitute a primary source of industrial methane emissions, and the requirements finalized in this rulemaking must help materially reduce harmful emissions from existing facilities. Most of these facilities are operating today without the protections afforded either by the U.S. Environmental Protection Agency's ("EPA") 2016 New Source Performance Standards,[9] which the EPA has proposed to significantly revise and fundamentally weaken,[10] or even by the limited and outdated VOC controls imposed by DEP's Air Quality Permit Exemption Category No. 38 ("Exemption 38"). If Pennsylvania is going to reach its climate commitments, DEP must

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[5] 42 U.S.C.A. §§ 7401—7671q

[6] *See* Environmental Defense Fund, "Pennsylvania Oil and Gas Emissions Data," available at: https://www.edf.org/pa-oil-gas/#/reports

[7] Int'l Panel on Climate Change (IPCC), *Climate Change 2013: The Physical Science Basis, Contribution of Working Group I to the Fifth Assessment Report* (Thomas Stocker et al., eds. 2013), Chapter 8- Natural and Anthropogenic and Natural Radiative Forcing, at 714 https://www.ipcc.ch/pdf/assessment-report/ar5/wg1/WG1AR5_Chapter08_FINAL.pdf; Bradbury et al., Dep't of Energy, Office of Energy Policy and Systems Analysis, *Greenhouse Gas Emissions and Fuel Use within the Natural Gas Supply Chain – Sankey Diagram Methodology* (July 2015), at 10, https://www.energy.gov/sites/prod/files/2015/07/f24/QER%20Analysis%20-%20Fuel%20Use%20and%20GHG%20Emissions%20from%20the%20Natural%20Gas%20System%2C%20Sankey%20Diagram%20Methodology_0.pdf (explaining how the effects of oxidation increase the IPCC's global warming potential values for methane to 87 over a 20-year timeframe an 36 over a 100-year timeframe).

[8] IPCC, *Climate Change 2013: The Physical Science Basis, Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* (Thomas Stocker et al., eds. 2013) (calculation based on Chapter 8), https://www.ipcc.ch/site/assets/uploads/2018/02/WG1AR5_all_final.pdf; *see also* Drew T. Shindell et al., Improved Attribution of Climate Forcing to Emissions, 326 SCIENCE 716, 717 (2009).

[9] *Oil and Natural Gas Emission Standards for New, Reconstructed, and Modified Sources*, 81 Fed. Reg. 35,824 (June 3, 2016) (codified at 40 C.F.R. pt., 60, subpt. OOOOa).

[10] *Oil and Natural Gas Emission Standard for New, Reconstructed, and Modified Sources Reconsideration*, 83 Fed. Reg. 52,056 (Oct. 15, 2018).

aggressively move forward with this rulemaking package and other controls on greenhouse gas pollution.

In addition to securing much-needed reductions of methane, the proposed rulemaking will help reduce emissions that contribute to ground-level ozone, the main constituent of smog. VOC and nitrogen oxides (NOx) react in the presence of sunlight and heat 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. According to EDF, upstream oil and gas sites in Pennsylvania emitted over 63,000 tons of VOC in 2017 alone.[11] The proposal will also help reduce this sector's emissions of hazardous air pollutants such as benzene and formaldehyde, known human carcinogens.

Ground-level ozone generated by pollution from the oil and gas industry has a sizable effect on the health of Pennsylvanians. For example, Clean Air Task Force modeled health impacts from ozone precursor emissions from oil and gas sources on populations in Pennsylvania. These impacts include more than 30,000 asthma attacks per year, over 22,000 lost school days, and over 67,000 person-days when adults need to rest or reduce their activity because of high ozone levels.[12] Pennsylvanians will clearly see health benefits from the reductions of VOC emissions that will result from this proposal.

Importantly, states downwind of Pennsylvania will also see significant benefits from reductions in VOC pollution from our oil and gas sector. The modeling by Clean Air Task Force referenced above finds that residents of downwind states (Maryland, Delaware, New Jersey, New York, and New England states) experience more than 40,000 asthma attacks per year from oil and gas industry pollution,[13] demonstrating that it is also highly appropriate for Pennsylvania to reduce VOC pollution from this industry as part of its obligations under the Clean Air Act.

Environmental Commenters offer concrete recommendations, based on precedent established by other leading oil and gas jurisdictions, to strengthen several provisions of the proposed rulemaking and ensure that it is more protective from both public health and climate perspectives. In terms of achieving the most significant additional emission reductions, we strongly urge DEP to strengthen the proposed fugitive emissions components requirements.

First and foremost, we urge DEP to revisit the production threshold in the proposed rule that would limit applicability of the rule's leak detection and repair (LDAR) requirements to only those well sites with a well that produces, on average, greater than 15 barrels of oil equivalent per day. According to DEP's own estimates, over 99% of Pennsylvania's conventional wells reporting production fall below this threshold and would therefore be exempted from this rule's LDAR requirements.

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[11] "Pennsylvania Oil and Gas Emissions Data," *supra* note 6.

[12] *See* L. Fleischman *et al.*, "Gasping for Breath: An analysis of the health impact from ozone pollution from the oil and gas industry," available at: https://www.catf.us/resource/gasping-for-breath/. Impacts listed are those that occur in Pennsylvania, attributable to nationwide industry emissions. Although not quantified, a significant portion of the health impacts felt by Pennsylvanians are due to oil and gas industry emissions from Pennsylvania.

[13] Ibid.

We also urge DEP to eliminate the provision that allows well site operators to reduce the frequency of LDAR inspections if the percentage of leaking components identified on-site is less than 2% for two consecutive quarterly inspections. Research shows that large, uncontrolled leaks are random and can only be detected with frequent and regular inspections, because leaks re-occur at facilities. Environmental Commenters provide further recommendations on other provisions of the proposed rulemaking to deliver additional emission reductions and ensure consistency of control requirements for all Pennsylvania operators and sources in the oil and gas sector.

We commend DEP for drafting, and the EQB for adopting, this proposed rulemaking. Environmental Commenters respectfully urge you to adopt the following recommendations for strengthening and, in some instances, clarifying the proposal. We appreciate your consideration and look forward to working with agency staff to support Pennsylvania in establishing cost-effective standards to reduce methane and VOC pollution and protect public health.

I. Leak Detection and Repair

DEP's proposed control requirements for fugitive emissions components establish a baseline quarterly inspection frequency with one of three types of leak detection methods: optical gas imaging (OGI), a gas leak detector that meets the requirements of Method 21, or another device approved by DEP.[14] 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. The proposed rulemaking further allows well site operators to reduce the inspection frequency to semi-annual if the percentage of leaking components is less than 2% for two consecutive inspections. The inspection frequency reverts to quarterly if at any time the percentage of leaking components is higher than 2%.

We support DEP's proposal to require a quarterly LDAR program at oil and gas facilities, especially a baseline quarterly inspection requirement for applicable well sites. A number of leading states already 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 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 inspect facilities for abnormal operating conditions, repair any such conditions expeditiously, and document and report the results of inspections. Furthermore, robust, detailed recordkeeping and reporting requirements are critical to compliance monitoring and enforcement. They also provide important information on the efficacy of LDAR programs.

[14] Proposed Annex A, §129.127(b)(1)(ii)(B)(III) and §129.127(d)(2)(iii).

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

(1) **Remove the production threshold that would limit applicability of the LDAR requirements to only those well sites with a well that produces, on average, greater than 15 barrels of oil equivalent per day ("low-producing well exemption").**

(2) **Remove the provision that allows well operators to decrease the inspection frequency to semi-annual based on the percentage of leaking components; and**

(3) **Expand the definition of fugitive emissions components to include continuous- and intermittent-bleed pneumatic devices.**

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 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[15]—and that existing inventories do not accurately reflect the presence of these "super-emitters."[16] A 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.[17] 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

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[15] 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").

[16] Barnett Synthesis *supra* note 15 at 15599.

[17] 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).

proportional loss rates have excess emissions resulting from abnormal or otherwise avoidable operating conditions, such as improperly functioning equipment."[18] 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.[19]

- **Equipment Leaks are Unpredictable.** A number of studies have assessed whether well characteristics and configurations can predict super-emitters, concluding that they are only weakly related,[20] and that these emissions are largely stochastic. In particular, the Barnett coordinated campaign mentioned above found that abnormal operating conditions, such as improperly functioning equipment could occur at different points in time across facilities.[21] 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."[22] In addition, a recent helicopter study of 8,220 well pads in seven basins, including 2,067 well pads in the southwest Pennsylvania 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.[23] That study focused only on very high-emitting sources, given the helicopter survey detection limit which ranged from 35–105 metric tons per year (tpy) of methane. The paper reported that emissions exceeding the high detection limits were found at 327 sites. Ninety-two 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 an LDAR 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

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[18] Zavala-Araiza (2015), at 8167–8174.

[19] *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.

[20] 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 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.").

[21] Harriss (2015), *supra* note 17.

[22] Zavala-Araiza (2015), *supra* note 18.

[23] 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.

facilities.[24] 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.[25]

Other studies confirm these findings[26] and underscore the importance of frequent inspections to identify and repair stochastic, heterogeneous leaks.

Other states also have successful LDAR programs in place requiring frequent inspections for existing oil and gas sites. California requires quarterly LDAR at all production sites and compressor stations statewide,[27] and Wyoming requires quarterly LDAR at all new and existing well sites in the Upper Green River Basin with the potential to emit 4 tpy VOC from fugitive components.[28] In both states, operators may use Method 21, an OGI instrument, or another approved instrument.

Meanwhile, Colorado has required LDAR at existing oil and gas facilities since 2014. For well sites with potential emissions above 12 tpy VOC, Colorado requires quarterly instrumental inspection; if potential emissions exceed 50 tpy VOC, *monthly* inspection is required.[29] Additionally, any site with potential emissions over 2 tpy VOC that is within 1,000 feet of an occupied area must be inspected quarterly.[30] Note that when LDAR was first required in 2014, the state estimated that over 3,000 well production facilities would be subject to quarterly or monthly instrumental inspection.[31] The number of Colorado facilities subject to quarterly or more frequent LDAR today is now considerably higher.[32]

Since 2014, Colorado has already twice strengthened its LDAR program with rulemakings in 2017 and 2019. In both cases, building upon the effectiveness of the program in reducing emissions, the state increased the required instrumental inspection frequency at many sites that had been subject to less frequent LDAR under the initial rules.

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24 Barnett Synthesis, *supra* note 15 at 15600.
25 *Id.*
26 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.
27 CARB § 95668(g).
28 WY Permitting Guidance; Wyoming Department of Environmental Quality, Air Quality Division Standards and Regulations, Nonattainment Area Regulations, Ch. 8, Sec. 6.
29 Colorado 5 C.C.R. 1001-9, Regulation No. 7, § D.II.E.4.
30 Id.
31 Colorado Air Pollution Control Division, Cost-Benefit Analysis for Proposed Revisions to AQCC Regulations No. 3 and 7 (Feb. 7, 2014) Table 27, on file with CAC.
32 In addition to growth of the industry that has occurred in Colorado since 2014, the 2014 rules did not require quarterly LDAR at sites with potential VOC emissions of 2-12 tpy located less than 1,000 feet from an occupied area (this requirement was added in 2019).

Beyond Colorado's requirement for monthly inspections, some other leading operators and independent analysis also support a monthly inspection frequency for the largest well sites and compressor stations.

- **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 past decade and includes a monthly LDAR program using instrument-based surveys (i.e., OGI). According to Jonah, this program significantly reduces pollution while paying for its own costs: "[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 repairing the identified leaks."[33] 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.[34] Jonah's experience that gas savings from repairs often exceed its LDAR program's costs is also borne out by the Carbon Limits report[35] discussed below and analysis carried out by Colorado.[36] There is mounting industry-supplied evidence that frequent LDAR is cost-effective.[37]

- **Carbon Limits**. A study conducted by Carbon Limits on behalf of Clean Air Task Force determined that monthly surveys of well sites and gas plants have VOC abatement costs of under $3,500 per metric ton.[38]

1. DEP Should Remove the Low-Producing Well Exemption

The proposed rulemaking currently applies LDAR requirements only to those well sites with a well that produces, on average, greater than 15 barrels of oil equivalent per day.[39] This production threshold was adopted by the Department from EPA's recommendations in the 2016 Control Techniques Guidelines for the Oil and Natural Gas Industry (2016 O&G CTG) as constituting reasonably available control technology (RACT) for these sources in

[33] 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).

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

[35] 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.

[36] 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.

[37] 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).

[38] 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.

[39] Proposed Annex A, §129.127(a)(1).

Pennsylvania.[40] However, it is critical to note that the 2016 O&G CTG did not determine that sites with low-producing wells do not emit significant emissions through equipment leaks; rather, it simply declined "at this time . . . to include a RACT recommendation" for those well sites. As such, EPA "encourage[d] air agencies to consider site-specific data from these sources in their RACT analyses."[41]

DEP estimates that "[o]f the 71,229 conventional wells reporting production, only 303 are above the 15 barrel of oil equivalent per day production threshold as reported in the Department's 2017 oil and gas production database and will have fugitive emissions component requirements."[42] That equates to only 0.425% of these sources being subject to baseline quarterly LDAR requirements. The remaining 99.575% will have no inspection requirements whatsoever.

There is no site-specific data or analysis presented by DEP in the proposed rulemaking or supporting materials on either the costs or emission reduction benefits associated with implementing LDAR programs for low-producing wells, despite EPA's encouragement. Given the sheer volume of Pennsylvania wells that would be exempted from applicable LDAR requirements using this production threshold, as well as comprehensive analysis demonstrating these low-producing well sites emit nearly 600,000 short tons of methane per year[43], **we strongly urge DEP to remove this low-producing well exemption from the proposed rulemaking.**

DEP does not require that conventional well operators report their emissions, but it is estimated that these wells are responsible for over half the annual methane emissions from upstream oil and gas sites in Pennsylvania. This, despite the fact these sources contribute less than 10% of total natural gas production in Pennsylvania.[44] Other independent research has confirmed that marginal or low-producing wells are responsible for a disproportionate and significant amount of industrial methane pollution. A comprehensive report released this year found that low-producing wells emit ten times more methane than producing wells relative to total natural gas production.[45] For example, low-producing conventional well sites in the Marcellus showed a leakage rate of 11% while unconventional well sites emitted only about 0.1%. This exemption is simply not warranted by the scientific evidence.

From a climate perspective, all wells require routine, comprehensive inspections, regardless of production levels. If DEP insists on providing some form of exemption for low-producing wells, it must not extend that beyond those operators that own only a single marginal or stripper well. To the extent that there are concerns associated with robust LDAR requirements in unique circumstances, DEP could allow individually affected operators to apply for a dispensation from DEP pursuant to established criteria; but a blanket exemption from any routine inspections for nearly 71,000 wells based on the current applicability threshold is not supported

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[40] *See* 81 FR 74798 (October 27, 2016).
[41] Control Techniques Guidelines for the Oil and Natural Gas Industry 2016, at 9-38. https://www.epa.gov/sites/production/files/2016-10/documents/2016-ctg-oil-and-gas.pdf
[42] *See supra* note 1, at 2637.
[43] *See supra* note 6.
[44] M. Omara et al. (2016). Methane Emissions from Conventional and Unconventional Natural Gas Production Sites in the Marcellus Shale Basin. *Environ. Sci. Tech.* 50 2099. https://pubs.acs.org/doi/abs/10.1021/acs.est.5b05503
[45] A.P. Ravikumar et al. (2020). Repeated leak detection and repair surveys reduce methane emissions over scale of years. *Environ. Res. Lett.* 15 034029. https://iopscience.iop.org/article/10.1088/1748-9326/ab6ae1/meta

by the science or the record. Environmental Commenters urge DEP to remove this applicability threshold from the rule to ensure that emission leaks are quickly identified and repaired at all wells.

2. DEP Should Remove the Reduced Frequency Step-Down Provision

DEP's proposal also 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 subject to variable-frequency inspection requirements.[46] EPA observed: "Experience has shown that poor monitoring rather than good performance has allowed facilities to take advantage of the less frequent monitoring provisions."[47] 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 should monitor more frequently.[48] DEP should establish a rigorous and fixed baseline that incentivizes operators to find 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 small 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.

To demonstrate this as an empirical matter, we examined the effects of percent thresholds using data from the City of Fort Worth Study Air Quality Study,[49] 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 fewer than 2 percent leaking components constituted 90% of total emissions and 80% of all sites.

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[46] 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.
[47] *Id.* at 23.
[48] *Ibid.*
[49] Fort Worth Study, *supra* note 15.

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

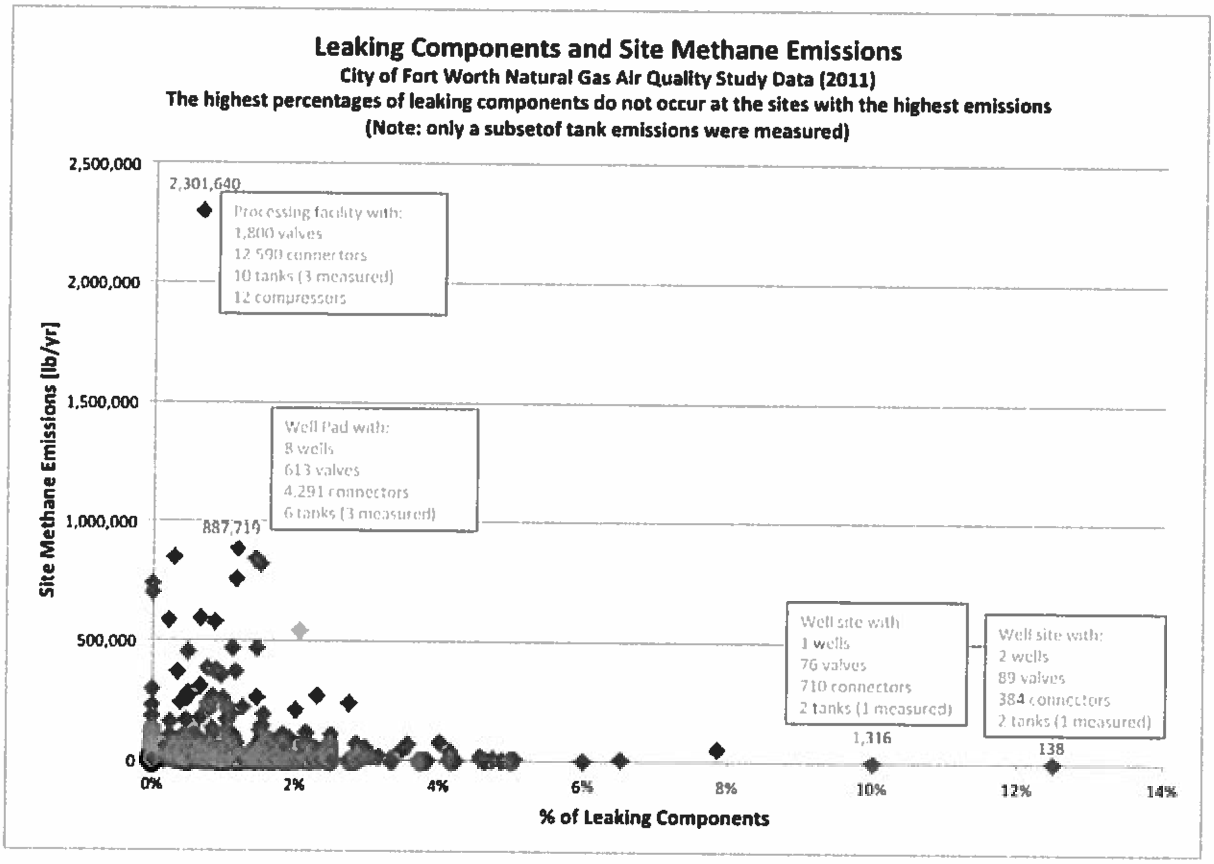
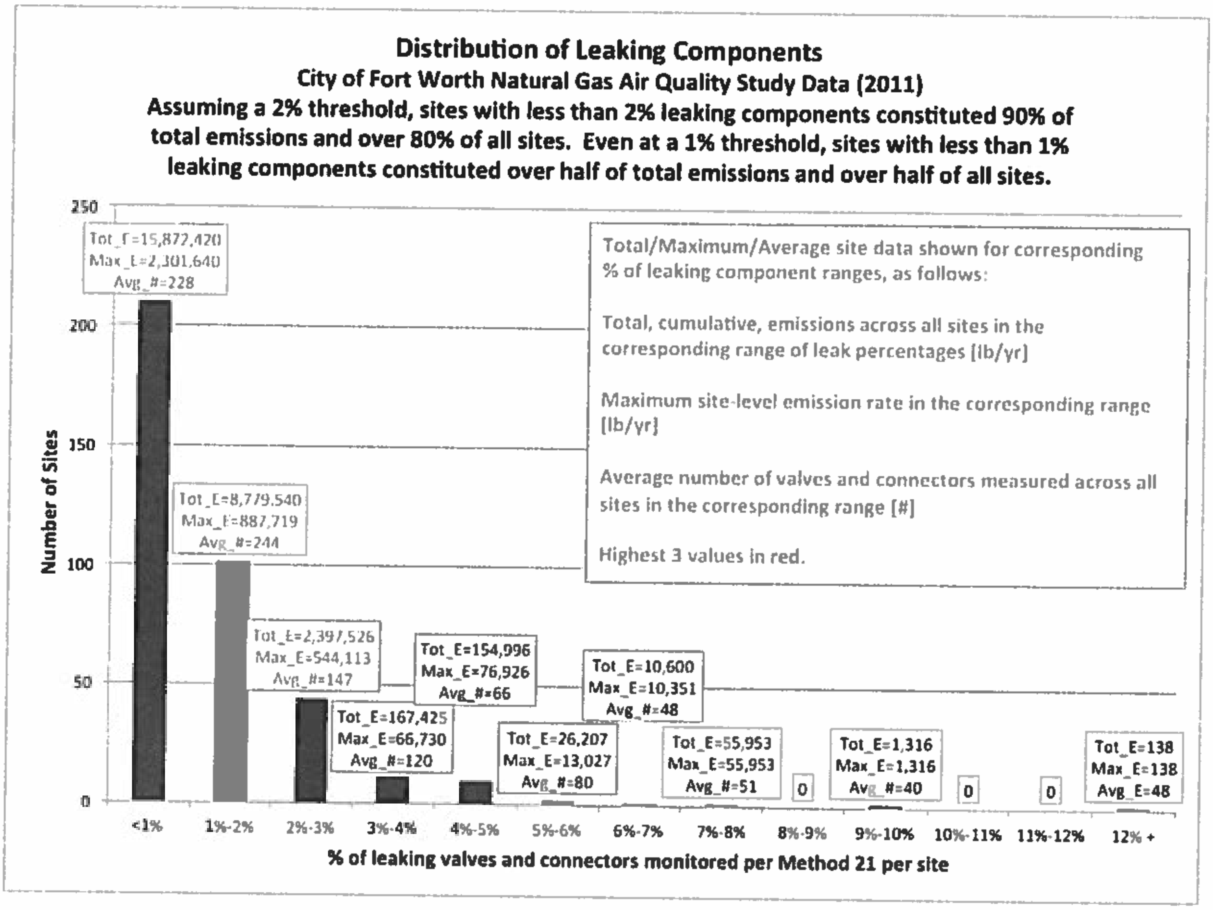


Figure 2: Number of Sites versus Percent of Leaking Valves and Connectors Monitored per Site (Method 21)



Additionally, several recent studies, including those in Pennsylvania, have shown that a majority of emissions come from a very small number of leaking components or "super-emitters."[50] For example, only about 1% of total components were found emitting using EPA's Method 21 approach, and only about 0.2% were found emitting using OGI cameras.[51] Therefore, even sites with high total emissions will likely have fewer than 2% of components leaking at any point. Independent operator data show that while the largest reductions in VOC emissions occur in the first year of an LDAR program, significant emission reductions are still achieved in subsequent years – because leaks re-occur at facilities.[52] This pattern was independently confirmed in supplementary analysis carried out by Carbon Limits on leak

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[50] A.R. Brandt et al. (2016). Methane Leaks from Natural Gas Systems Follow Extreme Distributions. *Environ. Sci. Technol.* 50 12512. https://pubs.acs.org/doi/abs/10.1021/acs.est.6b04303

[51] A.P. Ravikumar et al. (2017). Designing better methane mitigation policies: the challenge of distributed small sources in the natural gas sector. Environ. Res. Lett. 12 044023. https://iopscience.iop.org/article/10.1088/1748-9326/aa6791/meta

[52] *Id.* at 10-11.

inspection data from a number of well production facilities and compressor stations.[53] Carbon Limits found that inspectors continued to find leaks in repeat inspections at the same facility. Additionally, Carbon Limits found that, at facilities in Alberta subject to LDAR requirements, 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.

We thus urge DEP to remove provisions allowing operators to reduce inspection frequency based on the percentage of leaking components identified in prior surveys. Using any metric, 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.

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

We urge DEP to expand the scope of the LDAR program to apply the definition of "fugitive emissions component" to all sources of unintentional venting, including continuous- and intermittent-bleed pneumatic devices.[54] A series of studies demonstrates that both types of controllers can have significant emissions when malfunctioning. 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 reparable issues, and that "many of the devices in the high emitting group were behaving in a manner inconsistent with the manufacturer's design."[55] 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 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."[56] 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 at 5.1 standard cubic feet per hour (scfh), emissions from low-bleed pneumatic controllers were 270% higher than EPA's emissions factor for these devices.[57] Many low-bleed controllers are specified by their manufacturers to emit far less than this: EPA's Natural Gas STAR program has

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[53] 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.

[54] *See* Proposed Annex A, §129.122(a), *Fugitive Emissions Component* – (ii).

[55] 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. 633-640 (2014), http://pubs.acs.org/doi/pdf/10.1021/es5040156.

[56] *Id.* at 639.

[57] Allen, *et al.* (2013), *supra* note 15, at 17,771-72.

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)[58] 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 legally applicable threshold of 6 scfh for low-bleeds[59]—often much more—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.[60] 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 the result of improperly functioning or failed controllers.[61]

- **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.[62] 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 and reflect similar empirical outcomes to the studies discussed above, which did link high bleed rates to improperly functioning devices.

- **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.[63]

More recent studies have similarly found that pneumatic controllers frequently malfunction or operate improperly, leading to excess emissions. Luck *et al.* studied 72 controllers at 16 natural gas compressor stations, finding that 42% of these controllers were

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[58] 40 C.F.R. § 98.233(a).
[59] *Id.* § 60.5390(c)(1).
[60] Fort Worth Study, *supra* note 15.
[61] *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.")
[62] 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.").

[63] Carbon Limits (2014), *supra* note 35 at 12.

operating abnormally, with substantially higher emissions than normally-operating controllers.[64] Stovern *et al.* inspected 500 gas-emitting pneumatic controllers at 31 well production sites in Colorado's Denver-Julesberg basin and found maintenance issues frequently occurred in this large sample.[65] For example, they found that intermittent-bleed controllers made up 83% of the sample and over 11% of these devices were (improperly) continuously emitting.[66]

In light of these findings, DEP must extend the proposal's LDAR requirements to include both continuous- and intermittent-bleed controllers. These standards would be highly cost-effective. For instance, 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.

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 and would only modestly increase the expense of these surveys.

From a technical standpoint, LDAR requirements for pneumatic devices are easily achievable. 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 one to two minutes).

California has already established LDAR requirements for both continuous- and intermittent-bleed devices. On March 23, 2017, the California Air Resources Board (CARB) finalized standards regulating greenhouse gas emissions from oil and gas operations, which require inspection of intermittent-bleed pneumatic controllers for continuous emissions during

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[64] Benjamin Luck *et al.*, *Multiday Measurements of Pneumatic Controller Emissions Reveal the Frequency of Abnormal Emissions Behavior at Natural Gas Gathering Stations*, 6 Envtl. Sci. & Tech. Lett. 348, 352 (2019), https://pubs.acs.org/doi/10.1021/acs.estlett.9b00158.

[65] Michael Stovern *et al.*, *Understanding oil and gas pneumatic controllers in the Denver-Julesburg basin using optical gas imaging*, 70 *J. Air & Waste Mgmt. Assn.* 468, 489 (2020), https://doi.org/10.1080/10962247.2020.1735576.

[66] *Id.* The authors note that the 11% figure actually underestimates the frequency of continuous emissions from intermittent pneumatic controllers. See pp. 8-9.

LDAR inspections.[67] These standards require quarterly LDAR inspections of oil and gas wellpads and compressor stations,[68] and require checking all intermittent-bleed pneumatic controllers for improper continuous emissions during each inspection.[69] Controllers improperly emitting between actuation must be repaired. In addition, operators of any existing continuous-bleed controller (all 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 6 scf per hour.[70]

Colorado also has in place a specific program for operators to perform an instrumental inspection of all pneumatic controllers. The inspections must be carried out with the same frequency as LDAR inspections (that is, the frequency depends on potential VOC emissions from the site), so effectively pneumatics are inspected whenever operators must inspect a facility for leaks. This program was first required at sites in the Denver-Front Range ozone non-attainment area, where oil and gas activity is most intense in Colorado, in 2017.[71] Recognizing the effectiveness of this program in reducing emissions, the program was expanded statewide in 2019.[72] Note that *all* pneumatic controllers – including "low-bleed" and "intermittent-bleed" controllers – are covered during every inspection.[73]

Using these two state programs as examples, DEP should require operators to inspect any controller venting natural gas to the atmosphere to decrease the harmful excess emissions that these devices so often produce. Every device should be inspected with OGI or similar instruments, and operators should confirm that any continuous bleed device is emitting less than 6 scfh with a direct measurement.

II. Alternative LDAR technologies

We commend DEP for including a provision in the proposed rulemaking that allows for operators to use approved leak detection technologies other than OGI or Method 21.[74] We urge the agency to adopt a robust alternative compliance pathway that creates an entry point for appropriately qualified and demonstrated methane selective and/or multiple hydrocarbon detecting approaches and that allows for public participation in the approval of such alternative approaches.

The leak detection technology landscape is highly dynamic, with innovation happening in real time. DEP should create space for innovative technologies, which may be able to deliver improved environmental performance at reduced cost. Many recent scientific studies have demonstrated the potential for new technologies such as drones to rapidly detect leaks in a

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[67] 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.
[68] Cal. Code Regs. tit. 17, § 95669(a), (g), www.arb.ca.gov/regact/2016/oilandgas2016/oilgasfro.pdf.
[69] *Id.* § 95668(e)(3).
[70] *Id.* § 95668(e)(2)(A).
[71] Colorado 5 C.C.R. 1001-9, Regulation No. 7, § D.III.F.2.a.
[72] Id, § D.III.F.2.b.
[73] Id.
[74] *See supra* note 14.

variety of operating conditions.[75] In addition, these technologies can also measure leak rates, allowing DEP to develop improved emissions estimates.[76] These alternatives to OGI are often mounted on mobile platforms such as trucks, drones, and planes and have the potential to cover large areas in a short time, thus significantly reducing the cost of an LDAR program.

Colorado has adopted a rule and detailed guidance documents setting forth the specific elements an alternative leak detection technology must demonstrate, and the process by which such an alternative technology is reviewed and approved.[77] We urge DEP to adopt similar criteria, accompanied by clear and transparent instructions, governing the necessary elements of an application for an alternative technology and the approval process. Such an approach will help catalyze a race to the top in technology, control costs for the regulated community, and boost environmental outcomes. We caution DEP, however, to ensure that any process for approving alternative methods of LDAR allows only technologies that are shown to be at least as effective as OGI or Method 21.

III. Pneumatic Controllers

DEP Must Broadly Require Use of Zero-Emission Technology for Both Intermittent- and Continuous-Bleed Pneumatic Controllers

As discussed above, we urge DEP to include both intermittent- and continuous-bleed pneumatic controllers among the equipment that operators must cover in their LDAR inspections. This will ensure that improperly functioning devices are located and repaired on a regular basis. In addition, we also urge DEP to issue standards for these sources that broadly require the use of zero-emitting technology.

We know that emissions from continuous-bleed pneumatic controllers, even those designed to be "low-bleed," can be substantial. Indeed, DEP estimates that the most substantial emissions reductions for both methane and VOC from any source category under the proposed rulemaking will be from pneumatic controllers. In the preamble, the Department estimated the proposed control measures could reduce VOC emissions by 3,191 tpy from pneumatic controllers out of a total estimated 4,404 tpy VOC reduced across all sources (72.5%). DEP also estimates pneumatic controllers could reduce methane emissions by 61,421 tpy out of a total 75,603 tpy of methane reduced across all sources (81.2%)

The proposed rulemaking requires controllers to be "low-bleed," (i.e., have a bleed rate of less than or equal to 6 scfh) at most facilities and zero-bleed, if installed at a natural gas

[75] A.P. Ravikumar et al. (2020). Single-blind inter-comparison of methane detection technologies – results from the Stanford/EDF Mobile Monitoring Challenge. Elem. Sci. Anth. 7 37. https://www.elementascience.org/article/10.1525/elementa.373/

[76] T.A. Fox et al. (2019). A review of close-range and screening technologies for mitigating fugitive methane emissions in upstream oil and gas. *Environ. Res. Lett.* 14 053002. https://iopscience.iop.org/article/10.1088/1748-9326/ab0cc3/meta

[77] CO Reg. 7, § XII.8.a; CDPHE, Procedures on AIMM Process, AQCC Regulation No. 7, p. 3 (July 6, 2015) (accessible at https://www.colorado.gov/pacific/sites/default/files/AP-BusIndGuidance-AIMMprocessmemo.pdf).

processing plant.[78] 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.[79] Improperly functioning devices may result in substantial emissions.

We also know that emissions from intermittent-bleed pneumatic controllers, specifically in Pennsylvania, are substantial and much higher than emissions from high-bleed controllers. Intermittent-bleed devices are a major source of harmful air pollution that are not subject to any federal or Pennsylvania emissions standards. While there is currently no precise data for the exact number of these devices in Pennsylvania, based on EPA's Greenhouse Gas Reporting Program (GHGRP), we estimate that, in 2018, there were nearly 33,000 intermittent-bleed controllers with emissions of over 52,000 metric tons of methane in the state.[80] In contrast, we estimate that there were only about 73 high-bleed controllers in Pennsylvania in 2018, emitting about 340 metric tons of methane.[81] Clearly, by omitting intermittent controllers, DEP's proposed rulemaking will fail to address the vast majority of harmful VOC emissions from pneumatic controllers in the Commonwealth.

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 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

[78] Proposed Annex A, §129.124(c)(1).

[79] *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.

[80] 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_ONSHORE_WELLS: This table lists all of the 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. We estimated controller counts and emissions in Pennsylvania 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.

[81] *Id.*

[82] *See supra* note 55, at 637.

[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.

[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.

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 gas wells can produce large amounts of water in initial years, this is a relevant concern for Pennsylvania.

Second, as described above, 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. More recent studies of pneumatic controllers at compressor stations[86] and well production sites in Colorado[87] also found that these devices frequently operate improperly, leading to excess emissions.

Meanwhile, 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, and these options have been proven to work robustly in upstream oil and gas operations.[88] Specifically, Carbon Limits performed a comprehensive literature review and conducted 17 in-depth interviews with technology providers, as well as small and large oil and gas companies. This allowed Carbon Limits to compile up-to-date information on field experience with the implementation of zero-emission technologies, their applicability, and their costs.[89] 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.[90]

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[86] Luck *et al.* 2019 *supra* note 64, at 348.
[87] Stovern *et al.* 2020, *supra* note 65, at 468.
[88] 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).
[89] *Id.* at 7.
[90] *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.

Carbon Limits found that mature, reliable, and low-cost technologies are available in almost all situations to replace venting pneumatic equipment.[91] 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 emissions 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."[92]

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 EPA's NSPS Subpart OOOO rule). For example, an existing dry-gas facility with one continuous-bleed pneumatic controller and five intermittent-bleed pneumatic controllers (based on median wells drilled in Pennsylvania in 2016) would have an abatement cost of $781 per short ton of VOC abatement and $272 per metric ton of methane abatement.[93] To place this in context, the federal Interagency Working Group valued the social benefit of reducing one ton of methane as ranging from $520 to $3,200, with a "central" value of $1,200.[94]

Furthermore, these cost estimates 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. The calculations are also conservative because they consider only the cost of abating a single pollutant at a time (methane *or* VOC) 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.

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[91] *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.

[92] *Id.* at 4.

[93] Assuming $2/mcf gas, and emissions factors of 14.4 scfh for continuous-bleed controllers and 4.4 scfh for intermittent controllers. Costs were derived from interviews with oil and gas producers, system and component suppliers, and online quotes from component suppliers.

[94] Interagency Working Group on Social Cost of Greenhouse Gases, Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866: Application of the Methodology to Estimate the Social Cost of Methane and the Social Cost of Nitrous Oxide, 7 (Table 1) (Aug. 2016), https://obamawhitehouse.archives.gov/sites/default/files/omb/inforeg/august_2016_sc_ch4_sc_n2o_addendum_final_8_26_16.pdf. Although they likely underreport the true cost that greenhouse gas emissions pose to society, the Interagency Working Group's estimates of the social cost of greenhouse gases are by far the most accurate and comprehensive metrics thus far developed by the federal government. After the Trump Administration purported to rescind those values by executive order, Exec. Order. 13,783 § 5(b) (2017), EPA and other agencies began using a set of improvised, non-peer-reviewed "interim domestic" social cost of greenhouse gas values that effectively decimated the Interagency Working Group's estimates. As held in a recent federal court decision, the "interim domestic" values are arbitrary and capricious and "riddled with flaws," while the Interagency Working Group's values reflect "the best science available." *California v. Bernhardt*, 2020 WL 4001480, at *28 (N.D. Cal. July 15, 2020).

Recognizing the importance of moving to zero-bleed solutions as a means to eliminate harmful pollution from venting pneumatic controllers, two Canadian provinces with significant oil and gas production have finalized regulations that will sharply curtail the use of *any type of pneumatic controller* (high-bleed, low-bleed, and intermittent-bleed) which vents to the atmosphere. In British Columbia, all new facilities – including wellpads and compressor stations – cannot use venting gas-driven pneumatic controllers *of any type* after January 1, 2021.[95] Further, all large compressor stations will require retrofit of *all* venting gas-driven pneumatic controllers by January 1, 2022.[96] In Alberta, no new gas-driven venting pneumatic controllers can be installed at any facility (new or existing) after January 1, 2022.[97] Note that both provinces will additionally subject existing pneumatic controllers, including intermittent controllers, to various emission limits.[98]

These regulations show the confidence that these provincial governments and operators in Canada have in solar-powered electric controllers (grid power is unusual at production sites in Canada) and instrument air technology. Solar-powered controllers have been utilized for a number of years in Alberta where they are included in the design for separator equipment packages from certain manufacturers. Other operators have utilized similar solar-powered systems in custom configurations (for example to provide more electrical power and storage than is available in standard packages). Solar systems are used on all well sites, including those that are low-producing.

This technology has proven reliable in Alberta north of 55°N latitude, where: sunlight on a clear winter day is far weaker than in Pennsylvania; snowfall is higher; winter cloud cover is much more common; and winter temperatures are much lower (affecting battery capacity). In short, Environmental Commenters believe that there is no reason this technology cannot succeed in Pennsylvania.

IV. Emissions Threshold for Control of Storage Tanks

Environmental Commenters commend DEP for including in this proposed rulemaking an applicability threshold (based on potential VOC emissions) for control of certain storage tank emissions that is more stringent than EPA's recommendation in the 2016 O&G CTG. Whereas EPA recommended 95% reduction of VOC emissions only for those tanks with a potential to emit (PTE) of 6 tpy or greater across all facilities, DEP has adopted that applicability threshold only for those tanks located at a conventional well site or at an unconventional well site installed prior to August 10, 2013 (the effective date for Exemption 38 criteria).

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[95] See BC Regulation 282/2010, §52.05(2). http://www.bclaws.ca/civix/document/id/regulationbulletin/regulationbulletin/Reg286_2018.

[96] *Id.*, §52.05(3). Large compressor stations are defined as those with more than three megawatts (about 4,000 HP) of compression. See §52.05(1).

[97] See Alberta Energy Regulator (2020), "Directive 060 - Upstream Petroleum Industry Flaring, Incinerating, and Venting," §8.6.1. https://www.aer.ca/documents/directives/Directive060_2020.pdf.

[98] For example, British Columbia requires operators to limit emissions from all controllers, *including intermittent controllers*, to 6 scfh. See BC Regulation 282/2010, §52.05(4)(a). Alberta has specific standards for intermittent-bleed level controllers. See Directive 060 §8.6.1(3).

Otherwise, for storage tanks located in the transmission and storage segment or at natural gas gathering and boosting stations, processing plants, or unconventional well sites installed after August 10, 2013, DEP has established a PTE threshold of 2.7 tpy VOC. For storage vessels installed at those unconventional well sites, this stringency is consistent with the threshold used under Exemption 38, so this simply prevents backsliding for those sources. Nevertheless, this more stringent requirement is necessary for tanks at all facilities, and **we urge DEP to establish a PTE threshold of 2.7 tpy VOC for all storage tanks in the oil and gas sector.** This would ensure consistency of control requirements for owners and operators of storage tanks across Pennsylvania. DEP has described "great success with the 2.7 tpy VOC threshold in Exemption 38," which has been in place for seven years.[99] A threshold of 2.7 tpy VOC is also appropriate 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.

Furthermore, not only should there be a 2.7 tpy VOC threshold for all storage tanks in Pennsylvania, but **we urge DEP to define a "storage vessel" so that two or more physical tanks that are manifolded together are treated as a single unit for the purposes of determining applicability.** In recent years, it has become more common for multiple storage tank batteries, sometimes containing different liquids, to be manifolded at the emissions line and routed to a common control device. It is a more rational approach to use the sum total emissions from these tank batteries for applying control requirements and is consistent with the long-standing definition used in other jurisdictions like Colorado.[100] Otherwise, operators will be incentivized to install multiple smaller tanks on a site to avoid having a single tank that exceeds the emissions threshold and is subject to the 95% emissions control standard. Of course, actual emissions in that case would be as high as from a single uncontrolled tank.

V. Compressor Venting / Blowdowns

Compressors must periodically be taken off-line for maintenance, operational stand-by, or emergency shutdown testing. During this 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 often vented to the atmosphere. This process, known as a "blowdown," can produce significant emissions and is accompanied by loud noise pollution, which can spike up to 90 decibels. Episodic events like compressor blowdowns and methane slip from compressor exhaust are some of the largest sources of methane and VOC emissions.[101] Any effort to reduce emissions should also require control of these sources using best available management practices. This is

[99] DEP Technical Support Document, "General Plan Approval and General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (BAQ-GPA/GP-5A) and for Natural Gas Compressor Stations, Processing Plants, and Transmission Stations (BAQ-GPA/GP-5), p. 26 (Feb. 4, 2017), available at: http://www.depgreenport.state.pa.us/elibrary/GetDocument?docId=10735&DocName=TECHNICAL%20SUPPORT%20DOCUMENT%20FOR%20GP-5%20AND%20GP-5A.PDF%20%20%3Cspan%20style%3D%22color%3Ablue%3B%22%3E%3C%2Fspan%3E

[100] CO Reg. 7, § XVII.C, available at: https://www.colorado.gov/pacific/cdphe/aqcc-regs

[101] D. Zimmerle et al. (2020). Methane Emissions from Gathering Compressor Stations in the U.S. Environ. Sci. Technol. 54 7552. https://pubs.acs.org/doi/10.1021/acs.est.0c00516

especially critical for compressor stations, which are often located near homes and community spaces like schools and parks.

Unfortunately, there are no effective emission control requirements established in the proposed rulemaking for blowdown episodes. Members of Environmental Commenters' respective organizations have repeatedly expressed concerns over the years about the significant emissions associated with compressor station blowdowns. There are no notice requirements for scheduled blowdowns and no reporting or recordkeeping requirements for emissions from such events. Nor are there direct standards that require operators to reduce or control emissions during blowdowns. This is a significant gap in the proposed rulemaking. DEP's Marcellus Inventory, which collects data only from unconventional wells and compressor stations, shows that VOC emissions from blowdown vents alone exceeded 1,815 tons from 2012-2018.[102] Methane emissions from these sources exceeded 169,000 tons during this same period, and recent analysis clearly demonstrates the extent to which emissions are undercounted by inventory estimates. **Therefore, we urge DEP to include control requirements in this proposed rulemaking to reduce blowdown emissions.**

There are multiple cost-effective, technologically feasible means by which operators can responsibly control emissions from blowdowns, and we urge DEP to strengthen the proposed rulemaking 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 VOC and 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 technology that captures and controls emissions from compressor isolation valves and compressor blowdown vents.[103] Ohio EPA allows operators to meet this requirement in one of two ways: (1) a design that captures 100% of gasses from these sources and routes them to a flare designed for 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 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 adopt similar emission mitigation measures for blowdown events, with a decided preference for the control method that will result in the greatest emission reductions.

[102] DEP Air Emissions Report, http://cedatareporting.pa.gov/reports/powerbi/Public/DEP/AQ/PBI/Air_Emissions_Report.

[103] *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.

VI. Liquids Unloading and Pigging Operations as Additional Affected Source Categories

DEP properly acknowledges the benefits of establishing consistent control requirements among all oil and natural gas sources in Pennsylvania. On June 9, 2018, the Department finalized air pollution controls for new and modified natural gas facilities in General Plan Approval and/or General Operating Permit for Natural Gas Compression Stations, Processing Plants, and Transmission Stations (GP-5), and General Plan Approval and/or General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (GP-5A). These general permits promulgated standards for emissions sources previously uncontrolled in Pennsylvania, including wellbore liquids unloading operations and pigging operations.

Over time, liquids may accumulate in a producing well and may reduce pressure to the point where production is reduced, especially in wells located in wet gas areas. When this happens, the accumulated fluids need to be removed in order to restore production through a process called liquids unloading. There is considerable uncertainty about the true extent of methane and VOC emissions from liquids unloading events, but EPA inventory data and peer-reviewed research confirm they are responsible for a significant fraction of oil and gas industry emissions.[104] DEP stated "there has been great support in the comments for including [liquids unloading] in the GP-5A."[105] We commend the Department for addressing this emission source in GP-5A and urge DEP to include liquids unloading as a source category in this proposed rulemaking.

There are many different techniques that can be used to accomplish the removal of accumulated fluids from a well. DEP has stated that "one of the most effective methods" to reduce emissions, is "to ensure that an operator remains on site for the duration of a manual unloading operation."[106] Colorado and Wyoming have imposed similar requirements in recent years and, according to Wyoming regulators, this has helped significantly reduce liquids unloading emissions. DEP should also require the use of best management practices to mitigate methane and VOC emissions during liquids unloading, as established in GP-5A. This could include (but should not necessarily be limited to) the use of a plunger lift system, soaping, and swabbing, except where venting is necessary for safety. In all cases, DEP should require that an owner or operator capture the gas and direct it to a pipeline or process, unless there are safety reasons that require venting to the atmosphere.

For pigging operations, which are undertaken to remove accumulated water and condensate liquids in gas gathering pipelines and to maintain optimal pressure in a pipeline, DEP established an applicability threshold of 2.7 tpy VOC in GP-5 and GP-5A and required 95% emissions control. A pig must be loaded into a pipeline at a launching station and recovered at a

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[104] Testimony of David Lyon, "Methane emissions from liquids unloading and their implications for quantifying and mitigating emissions," (Apr. 15, 2019), available at: https://www.congress.gov/116/meeting/house/109319/witnesses/HHRG-116-II06-Wstate-LyonD-20190415-SD001.pdf

[105] *See supra* note 99, at page 52.

[106] *Ibid.*

receiving station and, in the process, gas in the chamber is vented to the atmosphere. Such venting can be reduced by routing the gas to a vapor recovery unit, flare, or other control device. DEP has acknowledged that many of these technologies and techniques are already employed in practice by industry operators.[107] EPA's Natural Gas STAR program also has materials available on additional methods to minimize emissions from pigging operations. Accordingly, to ensure consistency of control requirements across all oil and natural gas sources and to ensure additional emission reductions, **we urge DEP to include liquids unloading operations and pigging operations as additional source categories in this proposed rulemaking.**

For both of those processes—as with all emission mitigation efforts in the oil and gas sector—DEP should, wherever possible, require that captured emissions be routed to a pipeline or process rather than directed to a flare or incineration device. As discussed above, *see supra* note 93, incineration or flaring should be used as an emission control method only when no other options (apart from venting) are available; and venting must be permitted for these operations only as a true last resort to avoid safety hazards.

Respectfully submitted,

Joseph Otis Minott, Esq.
Executive Director and Chief Counsel
Robert Routh, Esq.
Public Policy and Regulatory Counsel
Clean Air Council
135 S. 19th St., Suite 300
Philadelphia, PA 19103

Robert Altenburg, Esq.
Director, PennFuture Energy Center
610 N. Third St.
Harrisburg, PA 17101

Mark Szybist, Esq.
Senior Attorney
Natural Resources Defense Council

Andres Restrepo, Esq.
Staff Attorney
Sierra Club
50 F St. NW, 8th Floor
Washington, DC 20001

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[107] *Id.* at page 48.

Leann Leiter
Pennsylvania & Ohio Field Advocate
Earthworks' Community Empowerment Project
PO Box 142
Canonsburg, PA 15317

David McCabe
Scientist
Darin Schroeder, Esq.
Attorney
Clean Air Task Force
114 State St.
Boston, MA 02109