Environmental Defense Fund

Thank you for accepting these comments submitted by Environmental Defense Fund ("EDF"). A nonprofit organization with over 3 million members worldwide and over 120,000 members in Texas, EDF is deeply concerned about the pollution emitted from oil and natural gas development and operations. EDF brings a strong commitment to sound science, collaboration, and market-based solutions to our most pressing environmental and public health challenges. Through research and advocacy, EDF has been driving action to cut methane pollution for over a decade.

I. Introduction

On March 8, 2024, EPA finalized the first standards of performance to address methane pollution from existing oil and gas sources. These commonsense standards will require all operators to monitor for and fix leaks and emissions from equipment failures; upgrade intentionally emitting equipment with zero-emitting alternatives; and limit the wasteful practice of routine flaring. According to EPA, implementation of standards of performance for existing sources will avoid the release of 35 million tons of methane to the atmosphere between 2024 and 2028.[1] The rules will also result in the reduction of harmful co-pollutants that contribute to direct public health impacts and regional ozone. EPA estimates that standards of performance for existing sources will reduce 8.6 million tons of volatile organic compounds that contribute to ground-level ozone[2] and approximately 320,000 tons of hazardous air pollutants, including benzene—a known human carcinogen—that threaten public health, between 2024 and 2028.[3]

We urge the Texas Commission on Environmental Quality to swiftly develop and propose strong methane standards, finalize these rules without delay, and submit a robust state plan to implement the Environmental Protection Agency's methane Emissions Guidelines, 40 CFR Part 60, Subpart OOOOc.

Our comments provide some background on the emissions profile of Texas' oil and gas sources, its impacts, and the myriad benefits for our air quality, health, climate, and energy future in significantly reducing pollution from the sector. Next, we summarize the presumptive standards of performance for existing sources set by EPA and illustrate that they are cost-effective, practical, and based on readily available technologies, even for marginal wells. Fourth, we describe the substantial flexibilities built into EPA's Methane Rule, and fifth, the limited role that exceptions under EPA's Remaining Useful

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[1] EPA, Regulatory Impact Analysis of the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, Table 1-3 (Dec. 2023) (hereinafter "RIA").

[2] *Id.*

[3] *Id.*

Life and Other Factors ("RULOF") exception will play. Finally, we identify opportunities for TCEQ to leverage its existing programs and historic public investments in methane mitigation to facilitate implementation of state methane standards.

II. Strong Rules are Vitally Important to Reduce Methane and Harmful Co-Pollutants from Existing Sources in Texas

Texas is the nation's largest oil and gas producer and emitter of oil and gas methane. Steep and rapid reductions of methane and other pollution from oil and gas operations are necessary to protect air quality and public health and slow near-term global warming exacerbating climate change. TCEQ must develop and implement rules to address the harm caused by these emissions, which will also promote sustainable economic development in the state.

1. Emissions from Texas' Oil & Gas Industry Harm Human Health, Drive Climate Change, and Risk Market Access for Texas' Energy Producers.

Methane from oil and gas equipment is emitted alongside harmful air pollution, including volatile organic compounds ("VOCs"), hazardous air pollutants, nitrogen oxides, and sulfur dioxide. VOCs and nitrogen oxides contribute to the formation of ground-level ozone, a respiratory irritant linked to a wide range of adverse health effects.[4] Oil and gas production operations emit benzene, a known human carcinogen,[5] and hydrogen sulfide, a poisonous air pollutant.[6] Pollution from venting and flaring operations contribute an estimated $7.4 billion in health risks and 710 premature deaths annually.[7]

Methane is a powerful greenhouse gas with over 80 times the warming power of carbon dioxide in its first twenty years in the atmosphere. Because of methane's elevated short-term impact, cutting this pollution is the quickest, most cost-effective way to slow the rate of climate change in the near term and avoid its worst impacts.[8] EDF estimates that oil and gas operators in Texas emitted 5,900,000 metric tons of methane in 2023 alone.[9] Using a 20-year global warming potential for methane, Texas' 2023 oil and gas

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[4] EPA, Health Effects of Ozone Pollution, https://www.epa.gov/ground-level-ozone-pollution/health-effects-ozone-pollution (last accessed January 13, 2025).

[5] See Health Impact of Oil and Natural Gas Operations, Ananya Roy, Sc. D and Tammy Thompson, Ph.D.,https://www.edf.org/sites/default/files/content/Appendix%20G%2C%20Roy%2C%20Thompson%2C%20Health%20Impacts%20of%20Oil%20and%20Natural%20Gas%20Operations.pdf, (November 25, 2019) 7-9, for a summary of the health impacts of benzene emissions from oil and gas operations.

[6] *See, e.g.* Townsend-Small et al, *High rates of hydrogen sulfide emissions measured from marginal oil wells near Austin and San Antonio, Texas,* 2024 *Environ. Res. Commun.* 6 (measuring high levels of H2S emissions from marginally producing and idle wells in central Texas).

[7] EDF, New study quantifies health impacts from oil and gas flaring in U.S., https://www.edf.org/media/new-study-quantifies-health-impacts-oil-and-gas-flaring-us (last accessed January 13, 2025).

[8] EDF, Study: Cutting Methane Emissions Quickly Could Slow Climate Warming Rate by 30%, https://www.edf.org/media/study-cutting-methane-emissions-quickly-could-slow-climate-warming-rate-30 (last accessed January 13, 2025).

[9] Methodology for Developing MAIR Informed State-Level Estimates: Integrating MAIR Regional Level Estimates with Additional Measurement-Based Estimates, available at https://library.edf.org/AssetLink/8m16021t5ci0a70d260xc2274ii4g038.pdf (last accessed January 13, 2025).

methane emissions are the equivalent of the annual emissions from 128 coal fired power plants run for a year and nearly 120,000,000 passenger cars. [10]

Methane is also the primary component of natural gas. When operators vent, leak, and flare methane, they also waste a natural resource and the taxpayer and royalty owners' financial stake in its development.[11] Broad and deep reductions in oil and gas methane are necessary keep Texas' oil and gas industry competitive in a global market increasingly demanding lower carbon products.[12]

2. *Texas has not directly regulated oil and gas methane before and has the most to gain from developing and implementing methane regulations.*

Texas does not directly regulate methane from sources in the oil and gas production and transportation sector at the state level.[13] However, as sources of air contaminants, oil and gas production and handling facilities are required to obtain authorization from TCEQ.[14] TCEQ has designed and implemented a system where most oil and gas production facilities are assumed to be insignificant emitters and thus able to authorize their emissions through permits by rule that do not contain robust pollution control requirements.[15] TCEQ's historic exercise of its permitting authority over the sector has resulted in a large population of underregulated sources of climate and air pollution.[16] Undoubtedly, these historic practices have created implementation challenges for both the agency and regulated entities but also reinforces the critical importance of

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[10] Emissions from the oil and gas sector account for a fifth of the state's industrial sector greenhouse gas emissions. TCEQ, Climate Pollution Reduction Grants Priority Action Plan for the State of Texas, 2-7, https://www.tceq.texas.gov/downloads/agency/climate-pollution-reduction-grants/20240301-texas-priority-action-plan.pdf (last accessed January 13, 2025).

[11] Synapse Energy Economics, Inc., *Methane Waste and Pollution in Texas*, https://www.synapse-energy.com/sites/default/files/Texas%20Methane%20Waste%20and%20Pollution%20Factsheet%2022-098.pdf (last accessed January 12, 2025) (analyzing the economic costs of methane wasted through venting, flaring, and leaks and finding that in 2019 alone, oil and gas operators wasted $1.7 billion of natural gas).

[12] *See* EDF, Methane mitigation: To stay competitive, Louisiana must meet the demand for cleaner energy, https://blogs.edf.org/energyexchange/2024/10/16/methane-mitigation-to-stay-competitive-louisiana-must-meet-the-demand-for-cleaner-energy/ (last accessed January 13, 2025).

[13] TCEQ has been delegated authority to implement the NSPS, including OOOOa which established methane standards for portions of the oil and gas sector.

[14] 30 TEX. ADMIN. CODE § 116.110(a).

[15] *See generally* TCEQ and RRC's Comments on EPA's Proposed Standards of Performance for New, Reconstructed, and Modified Sources, and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, February 13, 2023 at 10-11. For example, the permit by rule for production facilities established in 30 Tex. Admin. Code 106.352(l) does not require basic best management practices such as a leak detection and repair program.

[16] In comments to EPA, TCEQ indicates it has registration information for less than 10% of oil and gas sources in the state. *Compare* TCEQ and RRC's Comments on EPA's Proposed Standards of Performance for New, Reconstructed, and Modified Sources, and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, February 13, 2023 at 10-11 (stating that as of December 2022, the agency had 39,109 registered or permitted oil and gas sites and that "many" smaller sites may not be subject to registration requirements and are not reflected in that total) *with* "Wells Monitored by the Railroad Commission" as of December 2022, available at https://www.rrc.texas.gov/media/dmukdbx5/december-2022.pdf (reflecting 398,159 active and inactive oil and gas wells).

implementing common-sense standards now. Voluntary initiatives and general limitations alone are insufficient to constrain the industry's impact on our environment and health. As detailed below, the Methane Rule's performance standards offer reasonable and technologically available solutions for operators and the model rule provisions in 40 Code of Fed. Reg. §§ 60.5385c-60.5430c provides the framework for controlling this harmful pollution that Texas lacks.

TCEQ can also take advantage of a society-wide recognition of methane's risks and mitigation opportunities and the momentous advancements in methane measurement, monitoring, and mitigation technologies. EPA and the Department of Energy's recent announcement of $850 million in Methane Emissions Reduction Program ("MERP") funding for 47 projects is a reflection of the strength and value in America's growing methane mitigation ecosystem and the power of its innovation and workforce.[17] Many oil and gas operators recognize the threat of unabated methane emissions to their future and are making substantial investments to drive operations toward near-zero methane emissions.[18] A growing constellation of satellites are delivering transparent, accurate methane measurement data to help ensure policies and pledges are translating to real emissions reductions.[19] We applaud TCEQ for beginning to develop state methane standards for existing sources and are eager to collaborate with TCEQ and stakeholders to harness the methane momentum to facilitate implementation.

3. *Marginal Wells Comprise the Majority of Existing Wells Nationally, Yet Are Responsible for Disproportionate Amount of Pollution.*

EPA's presumptive standards of performance for existing sources address a significant and largely under or unregulated source of pollution: marginal wells (i.e., wells that produce less than 15 barrels of oil equivalent per day). According to EPA, marginal wells account for more than 75% of existing wells in the U.S.[20] In sum,

[17]Project Selections for FOA 3256: Methane Emissions Reduction Program Oil and Gas Methane Monitoring and Mitigation, https://www.energy.gov/fecm/project-selections-foa-3256-methane-emissions-reduction-program-oil-and-gas-methane-monitoring (last accessed January 13, 2025)

[18] *See, e.g.* EDF, Leading oil and gas companies and investors have rallied around EPA's new methane rules, https://business.edf.org/insights/leading-oil-and-gas-companies-and-investors-rally-around-epas-new-methane-rules-and-set-the-stakes-for-robust-implementation/ (last accessed January 13, 2025).

[19] We urge TCEQ to engage with UN Environment Programme's International Methane Emissions Observatory ("IMEO") to leverage methane emissions detection information received from satellites. IMEO collects and publishes data on methane emissions from oil and gas, as well as other, sources worldwide. Currently, sources of data include twelve high-resolution satellites capable of attributing methane emissions detection events to individual oil and gas facilities through IMEO's Methane Alert and Response System ("MARS"). Using enhanced AI capabilities and remote sensing experts, MARS is able to validate such detections within 15 days of image acquisition. Government entities may sign up to receive alerts of oil and gas methane emissions detections from MARS by nominating a "focal point" to receive notification directly from IMEO. UN Environment Programme, IMEO 2024 Report, "Invisible but not unseen. How data-driven tools can turn the tide on methane emissions-if we use them," https://wedocs.unep.org/bitstream/handle/20.500.11822/46541/eye_on_methane_2024_invisible_but_not_unseen.pdf?sequence=3 (last accessed January 13, 2025).

[20] EPA Background Technical Support Document (TSD) for the Final New Source Performance Standards (NSPS) and Emissions Guidelines, at 6-1 (Nov. 2023) (hereinafter "2023 TSD").

marginal oil and gas wells produce a small fraction of oil and gas, yet they are responsible for a disproportionately high amount of pollution, primarily because such wells tend to be under-inspected and poorly maintained.

According to EPA, in 2021 78% of all producing wells in the U.S. were marginal wells. Marginal oil wells produced only 7% of total oil production and marginal gas wells produced about 7.5% of total gas production.[21] Despite being responsible for a small fraction of US oil and gas production, recent studies document that these wells are significant polluters. A 2022 DOE study found that marginal oil wells were responsible for 59% of the cumulative methane emissions from oil and gas production. Marginal gas wells were similarly responsible for 37% of the cumulative methane emissions.[22] A second study, also conducted in 2022, similarly found that marginal wells account for approximately 37-75% of well site emissions—roughly equivalent to the climate forcing pollution emitted from 88 coal-fired power plants.[23] Fortunately, frequent inspections of marginal wells that alert operators to mechanical issues and broken equipment can abate much of this pollution. In many cases, repair of leaks at such wells results in gas savings that can offset or pay for inspection costs. The wasted gas at these facilities is valued at approximately $700 million, assuming 2019 prices.[24]

III. The Presumptive Standards of Performance are Reasonable, Cost Effective, Practical, and Based on Available Technologies

EPA's presumptive standards are based on available, cost-effective technologies and in many instances mirror requirements already on the books in multiple jurisdictions.

1. Leak Detection and Repair

A. Frequent Leak Inspections Is a Common Pollution Reduction Measure

EPA's Methane Rule requires operators inspect for leaks using a suite of available technologies and approaches already in use by operators around the country. Depending on the type of facility, and the equipment onsite, operators can use either optical gas imaging ("OGI") cameras, Method 21 ("M21"), or audio, visual, olfactory ("AVO") inspections to inspect for leaks. Where an instrument inspection is required, operators must also conduct periodic AVO inspections. Specifically, single wellhead only sites and small well sites[25] are subject to quarterly AVO requirements. Multi-wellhead only sites are subject to semi-annual OGI or M21 inspections and quarterly AVO inspections. Well sites with major production and processing equipment and

[21] *Id.* at 6-2.
[22] *Id.*
[23] Omara, Mark, et al. "Methane emissions from US low production oil and natural gas well sites." *Nature Communications* 13.1 (2022): 2085.
[24] EDF, New Study: Low-Producing Oil and Gas Wells Drive Roughly Half of Well Site Methane Pollution Nationwide, https://www.edf.org/media/new-study-low-producing-oil-and-gas-wells-drive-roughly-half-well-site-methane-pollution
[25] 40 C.F.R. § 60.5430c. *Small well site* means...a well site that contains a single wellhead, no more than one piece of certain major production and processing equipment, and associated meters and yard piping. Small well sites cannot include any controlled storage vessels (or controlled tank batteries), control devices, or natural gas-driven process controllers, or natural gas-driven pumps.

centralized production facilities[26] are subject to quarterly OGI or M21 inspections and bimonthly AVO inspections.

LDAR is a time-tested method for finding and eliminating leaks from oil and gas sites. Numerous US states have required oil and gas operators to inspect for leaks using OGI cameras or M21 hydrocarbon analyzers for years, and in some instances, decades. EPA has also required operators conduct LDAR inspections at gas processing plants since 1988 and at well sites and compressor stations since 2016. The following oil and gas producing states require operators to conduct LDAR inspections using M21 or OGI:

- **Colorado:** Colorado has required OGI or M21 inspections at well sites with emissions over specified thresholds since 2014. Currently Colorado requires monthly inspections at new well sites, other than those designed to avoid major emissions sources or with continuous monitoring,[27] and a range of annual through bimonthly inspections at existing well sites, depending on the facility's location and emissions potential.[28] Operators must also conduct monthly AVO inspections in addition to OGI or M21 inspections.[29] Colorado also allows operators to apply for approval to use an advanced methane detection technology or method.[30]
- **New Mexico:** In 2022 the New Mexico Environment Department adopted a rule requiring monthly, semi-annual, or annual inspections OGI or M21 at new and existing well sites, depending on emissions potential and the facility's location.[31] Operators must also conduct AVO inspections in addition to OGI or M21 inspections.[32] New Mexico also allows operators to apply for approval to use an advanced methane detection technology or method.[33]
- **Pennsylvania:** Pennsylvania requires quarterly or semi-annual OGI or M21 inspections at well sites permitted under its General Permit GP5A which was first available to operators in 2018.[34] Other existing sources not permitted under this General Permit must conduct quarterly, semi-annual, or annual inspections OGI or M21, depending on production thresholds.[35] Operators may apply to DEP to use alternative advanced detection technologies.[36]
- **Wyoming:** Wyoming first required operators conduct quarterly OGI or M21 inspections at facilities located in its Upper Green River Basin in 2015.[37]

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[26] The "well sites and centralized production facilities with major production and processing equipment" subcategory includes well sites and centralized production facilities that have: (1) One or more controlled storage vessels, (2) one or more control devices, (3) one or more natural gas driven pneumatic controllers or pumps, or (4) two or more other major production and processing equipment. 87 Fed. Reg. 74702, 74723.
[27] 5 Colo. Code. Regs. § 1001-9-B-II.E.4.f. ("Colorado Reg.7")
[28] 5 Colo. Code. Regs. § 1001-9-B-II.E.3, II.E.4.
[29] Colo. Code regs. § 1001-9-B-II.E.4.e.
[30] Colo. Code regs. § 1001-9-B-II.E.4.f.
[31] New Mexico Code R. § 20.2.50.116.C.(3)
[32] New Mexico Code R. § 20.2.50.116.B.(1),(2).
[33] New Mexico Code R. § 20.2.50.116.D.
[34] 25 Pa. Code § 129.127(c)(2); § 129.137(c)(2).
[35] Pa. Code § 129.127(c)(2), (3); § 129.137(c)(2),(3).
[36] 25 Pa. Code § 129.127(c)(2)(ii); 25 Pa. Code § 129.137(c)(2)(ii);
[37] Wyoming Nonattainment Area Regulations § (6)(g)(1)(a).

- **Ohio** requires operators to conduct quarterly inspections using a FLIR camera or M21, with stepped-down intervals if 2.0% or less of equipment are determined to be leaking.[38]
- **California:** California has required quarterly M21 inspections at production, gas processing, and compression facilities in the gathering and boosting and transmission natural gas segments since 2017.[39] Operators may use OGI as well, however if they do so, they must follow up with a M21 inspection since CARB requires operators quantify all detected leaks.[40]
- **US EPA:** EPA first required gas processing plants conduct LDAR in 1988[41] and new production sources and compressor stations to conduct semi-annual OGI or M21 inspections in 2016.[42]

The plethora of state LDAR requirements, as well as EPA's 2016 LDAR requirements, demonstrate the availability and reasonableness of EPA's LDAR requirements for designated facilities.

B. OGI is the best system of emission reduction

Building from extensive experience, past regulations, and the experience of leading states, the Methane Rule appropriately allows operators to use OGI cameras to detect fugitive emissions. OGI is a proven technology that has now been deployed for detecting and mitigating fugitive emissions from oil and gas operations for well over a decade.[43] EPA and other regulators have long relied on OGI monitoring because of its proven ability to detect emissions from a wide range of equipment and its ability to precisely pinpoint emission sources that can then be prioritized for repair.[44] This technology has been extensively tested and evaluated in the field,[45] and it has also been deployed and used successfully by operators for years.[46]

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[38] Ohio General Permits 12.1(C)(5)(c)(2); Ohio General Permits 12.2(C)(5)(c)(2).
[39] 17 Cal. Code Regs. § 95669.
[40] Cal. Code Regs. Tit. 17, § 95669(b).
[41] 40 CFR Part 60 Subpart KKK.
[42] 81 Fed. Reg. 35824, 35856 (June 3, 2016).
[43] *See, e.g.*, Reg'l Air Quality Council, *RAQC Announces Optical Gas Imaging Camera Loan Program* (April 23, 2012), https://raqc.org/regional_air_quality_council_announces_optical_gas_imaging_camera_loan_prog/.
[44] *See* Teledyne FLIR, *Optical Gas Imaging Regulations in the United States and Europe*, https://www.flir.com/discover/instruments/gas-detection/optical-gas-imaging-regulations-in-the-united-states-and-europe/ (last visited Feb. 11, 2023).
[45] *See, e.g.*, Daniel Zimmerle et al., *Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions*, 58 Env't Sci. Tech. 11506 (2020), https://pubs.acs.org/doi/10.1021/acs.est.0c01285; Seth N. Lyman et al., *Aerial and ground-based optical gas imaging survey of Uinta Basin oil and gas wells*, 7 Elementa: Sci. of the Anthropocene 43 (2019), https://online.ucpress.edu/elementa/article/doi/10.1525/elementa.381/112514/Aerial-and-ground-based-optical-gas-imaging-survey.
[46] Jonah Energy, for example, has used this technology since 2005 to reduce its emissions by 75%. *See* FLIR Media, *Optical Gas Imaging at Jonah Energy* (May 2016), http://www.flirmedia.com/MMC/THG/Brochures/OGI_014/OGI_014_EN.pdf; Teledyne FLIR, *Jonah Energy Reduces Fugitive Natural Gas Emissions by 75% Using FLIR OGI Camera* (Feb. 2021), https://www.flir.eu/discover/instruments/gas-detection/jonah-energy-reduces-fugitive-natural-gas-emissions-by-75-percent-using-flir-ogi-camera/.

LDAR programs using OGI cameras are a highly effective, low cost, and proven means for reducing fugitive emissions. Numerous studies have shown that over time and with repeated inspections, OGI programs reduce emissions and also help to prevent large emission events.[47] Studies have indicated that such LDAR programs are highly effective—some finding that more than 90% of leaks remained fixed a year later.[48] The same study found that "emissions reduced by 44% across all 8 facilities between the first and second LDAR survey," similar to EPA and Environment and Climate Change Canada's assumption that an annual OGI-based LDAR survey will reduce emissions by 40%.[49] However, it also found that each individual survey reduced a site's overall fugitive emissions by only 22% on average because of new leaks that occurred afterwards, indicating that "frequent LDAR surveys might be necessary for long-term emissions management."[50]

EPA's assumptions about the effectiveness of OGI are also supported by recent data and FEAST modeling. In Colorado for example, instrument-based monitoring (typically with OGI cameras) inspections found 90% of leaks, despite constituting just 5% of total inspections in 2020.[51] This closely mirrors 2019 annual data, where 89% of leaks were found with instrument-based monitoring. Studies have produced similar results, for example finding that "over 80% of emissions can be detected [with OGI] from an imaging distance of 10 m."[52]

C. Leak Detection and Repair Requirements are Cost Effective

EPA's LDAR requirements are cost effective. Fugitive monitoring and repair with OGI cameras is low cost, with a commonly cited per-site inspection cost of $600.[53] With new regulatory requirements, company-set emission reduction targets, and rapid growth in the methane mitigation sector,[54] it is likely that OGI monitoring will become even lower cost in the coming years and prior to the initial date for existing source compliance.

EPA's LDAR requirements are cost effective. EPA estimated the cost effectiveness for the OGI and AVO inspections for each type of facility. Each LDAR requirement falls within EPA's range for cost effectiveness.

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[47] Jiayang Wang et al., *Large-Scale Controlled Experiment Demonstrates Effectiveness of Methane Leak Detection and Repair Programs at Oil and Gas Facilities*, EarthArvXiv (2021) (non-peer reviewed preprint), https://eartharxiv.org/repository/view/2935/; Arvind P. Ravikumar et al., *Repeated leak detection and repair surveys reduce methane emissions over scale of years*, 15 Env't Rsch. Letters 034029 (2020), https://iopscience.iop.org/article/10.1088/1748-9326/ab6ae1/pdf [hereinafter Ravikumar 2020].
[48] Ravikumar 2020, *supra* note 47.
[49] *Id.*
[50] *Id.*
[51] Colo. Dep't Pub. Health & Env't, *2020 LDAR Annual Reports (Regulation 7 Section XVII)*, https://cdphe.colorado.gov/2020-ldar-annual-reports-regulation-7-section-xvii (last visited Feb. 11, 2023).
[52] Arvind P. Ravikumar et al., *Are Optical Gas Imaging Technologies Effective For Methane Leak Detection?*, 51 Env't Sci. Tech. 718 (2017), https://pubs.acs.org/doi/10.1021/acs.est.6b03906.
[53] U.S. Env't Protection Agency, *EPA's Methane Detection Technology Virtual Workshop Transcript Day Two* at 24 (Aug. 24, 2021) (Doc. ID No. EPA-HQ-OAR-2021-0317-0181).
[54] *See* Marcy Lowe, Datu Rsch., *Advanced Methane Monitoring: Gauging the Ability of U.S. Service Firms to Scale Up* (July 22, 2021), http://blogs.edf.org/energyexchange/files/2021/08/Advanced-Methane-Monitoring-Survey_DatuResearch_8-10-2021.pdf.

- Single wellhead only and small well sites. $1,181/ton of methane reduced.[55]
- Multi-wellhead only sites: $1,331/ton of methane reduced.[56]
- Well Sites with Major Production and Processing Equipment and Centralized Production Facilities: $611/ton of methane reduced.[57]
- Compressor stations: $707/ton of methane reduced.[58]
- Gas Processing Plants: $850/ton methane reduced.[59]

The costs to conduct LDAR inspections falls well below EPA's upper threshold for the cost effectiveness of reducing methane. EPA considers a standard to reduce methane cost effective if the standard can be achieved for a cost of $2,185 per ton of methane reduced or less.[60]

2. *Oil Wells that Produce Associated Gas*

   A. *EPA's Standard is Reasonable and Based on Existing State Requirements*

EPA's Methane Rule is reasonable and acknowledges the various abatement technologies operators can use to eliminate routine venting from oil wells. It also recognizes the different pollution potential of wells and allows operators to flare, rather than capture, associated gas from wells with smaller pollution potential. EPA's requirements are grounded in commitments made by leading oil and gas companies, requirements already in effect in multiple oil and gas producing states and cost effective, demonstrated technologies.

Recognizing that not all oil wells are created equal in terms of emissions potential, EPA finalized two separate presumptive standards for oil wells that produce associated gas: (1) those that emit CH4 emissions from associated gas venting of 40 tpy or greater and (2) those that emit less than 40 tpy of CH4 from associated gas venting. More stringent requirements apply to wells with the potential to emit more climate and health-harming pollution.

EPA determined that the best system of emission reduction for higher emitting wells—those that emit CH4 emissions from associated gas venting of 40 tpy or greater—is to route associated gas to a sales line. Alternatively, operators may utilize one of three abatement options that prevents emissions: (1) use the gas as an onsite source of fuel; (2) use the gas for another useful purpose that a purchased fuel or raw material would serve; or, (3) injecting the gas into the well or another well. If it is not technically feasible to capture the gas and route it to sales or utilize the gas for one of the beneficial

[55] 87 Fed. Reg. 74702, 74738, Table 15.
[56] *Id*. at 74738, Table 17.
[57] *Id*. at 74739, Table 19.
[58] *Id*. at 74735.
[59] *Id*. at 74809.
[60] *Id*. at 16864.

purposes noted above, operators may flare the gas using a device that achieves a 95% reduction in methane emissions.[61]

EPA determined that routing associated gas to a sales line is the best system of emission reduction for lower emitting wells—those with 40 tpy or less of CH_4 emissions from associated gas venting. These wells may also utilize one of the three abatement options noted above or flare the gas using a device that achieves a 95% reduction in methane emissions.[62]

Several major oil and gas producing states–New Mexico, Colorado, and Alaska–have recognized that routine flaring is no longer either acceptable or necessary and have adopted regulations that effectively prohibit the practice.

- In 2020, Colorado adopted regulations that prohibit venting and flaring during oil and gas production except as allowed by specified exemptions for temporary activities such as upset conditions and pursuant to a one-time, time-limited advance approval by the regulator under specified conditions.[63]
- New Mexico adopted regulations in March 2021 that similarly prohibit routine venting and flaring during production other than during specific temporary exemptions.[64]
- Alaska has severely restricted routine flaring for decades through regulations that treat as waste venting or flaring that continues after one hour, absent regulatory approval.[65]

Numerous leading companies, and consortiums of companies, have agreed to eliminate routine flaring. The World Bank's Zero Routine Flaring by 2030 Initiative "brings together governments, oil companies, and development institutions who recognize [routine flaring] is unsustainable from a resource management and environmental perspective, and who agree to cooperate to eliminate routine flaring no later than 2030."[66] As of 2022, there were 54 oil companies representing almost 60 percent of total global gas flaring that have committed under the Initiative to avoid routine flaring at new fields and end ongoing routine flaring by 2030.[67] Another industry group, the Texas Methane and Flaring Coalition, consisting of seven state trade associations and over 40 Texas

[61] *Id*. at 16835, Table 4.
[62] *Id*.
[63] 2 Colo. Code Regs. 404-1 § 903d.
[64] New Mexico Administrative Code, Venting and Flaring of Natural Gas, § 19.15.27.8(A).
[65] Alaska Administrative Code, 20 AAC § 25.235.
[66] The World Bank, Zero Routine Flaring by 2030 (ZRF) Initiative https://www.worldbank.org/en/programs/zero-routine-flaring-by-2030/initiative-text
[67] The World Bank, Global Initiative to Reduce Gas Flaring: "Zero Routine Flaring by 2030" List, https://thedocs.worldbank.org/en/doc/a903b5e6456991faf3b5e079bba0391a-0400072021/related/ZRF-Initiative-text-list-map-104.pdf

operators, has stated that "The Coalition agrees we should strive to end routine flaring…."[68] Exxon has halted all routine flaring in the Permian Basin.[69]

B. EPA's Associated Gas Requirement is Cost Effective

Multiple cost-effective options are available to eliminate routine venting of associated gas. While EPA acknowledged that multiple technologies exist, it only evaluated the costs of routing emissions to a flare and routing emissions to sales. EPA found both to be cost effective. Other information in the administrative record demonstrates that three other abatement solutions are also available and cost effective, depending on facility characteristics.

For existing wells, EPA estimated the incremental cost of routing the associated gas to a flare and routing it to sales line. EPA conducted two analyses for this scenario: In one analysis it assumed that the operator is venting gas from the existing well. In the second analysis, EPA assumed the operator is flaring the gas. EPA's estimated annual incremental costs under the first scenario ranging from a net savings to a cost of $40,064, depending on the diameter of the pipeline and the distance between the well and the sales line. EPA's estimated annual incremental costs under the second scenario ranged from net savings to a cost of $76,108, depending on the diameter of the pipeline and the distance between the well and the sales line.[70]

An independent report prepared by Rystad provides different cost estimates for routing associated gas to sales and also provides cost estimates for the three alternative abatement options EPA allows, but did not analyze. Per the report, routing associated gas to sales and using associated gas on-site are options that result in net savings to the operator. Specifically, Rystad estimates that connecting wells to gathering infrastructure results in an average net profit to operators of $3.10 per thousand cubic feet (kcf) and average *negative* costs of $162 per metric ton of methane flaring avoided.[71] Operators will pay between $0.40 and $0.80 per kcf handled by third party processing and gathering, netting profit after gas sales of $2.70 to $3.50 per kcf.[72] This corresponds to a range of *negative $141-183 per metric ton of methane abated*.[73]

Rystad estimates that using associated gas onsite as a source of fuel also results in a net profit of $8.60/kcf and $449 per MT of methane flaring avoided, after accounting for cost savings from fuel switching.[74] For a site producing 50 kcf per day of associated

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[68] Texas Methane and Flaring Coalition, Flaring Recommendations and Best Practices, 2 (June 16, 2020), https://texasmethaneflaringcoalition.org/wp-content/uploads/2020/06/6-16-20-TMFC-Flaring-Recommendations-Best-Practices-Report.pdf.
[69] Sabrina Valle, *Exclusive: Exxon halts routine gas flaring in the Permian, wants others to follow* (Jan. 24, 2023), https://www.reuters.com/business/energy/exxon-halts-routine-gas-flaring-permian-wants-others-follow-2023-01-24/.
[70] 2023 TSD 4-13, Table 4-4.
[71] Rystad Energy, *Cost of Flaring Abatement, Final Report*, at 11 (Jan. 31, 2022) (hereinafter "Rystad"). Attachment A. Additional detail on Rystad's analysis illustrating how Rystad derived cost ranges is included in Rystad Energy, *Flaring Abatement Input Costs*, Attachment B.
[72] *Rystad* at 45.
[73] *Id*.
[74] *Id.* at 11.

gas, costs associated with onsite power generation include between $1.90 to $2.20 per kcf for a small power generator and between $0.60 to $1.70 per kcf for gas treatment, netting between $7.70 to $9.40 in profit per kcf.[75] This corresponds to a range of *negative $402-491 per metric ton of methane abated*.[76] Onsite use is an effective option for sites flaring a relatively small amount of gas (less than 100 kcf/day).[77]

Operators may also convert associated gas to compressed natural gas and truck the gas offsite. This option is effective for sites flaring more than 250 kcf/day of gas.[78] Rystad finds that on average, compressed natural gas (CNG) trucking will cost operators $1.8/kcf, or $94 per metric ton of methane flaring avoided.[79] At a site producing 250 kcf per day of associated gas, costs associated with CNG include between $0.60 to $1.70 per kcf for gas treatment, $0.30 to $1.00 per kcf for compression, and $2.60 to $4.10 per for 200 miles of transportation, for a net cost after gas sales of between $0.10 to $3.40 per kcf.[80] This corresponds to a range of *$5 to $177 per metric ton of methane abated*.[81]

Lastly, Rystad analyzed the cost of injecting associated gas into underground storage wells. injection costs. Injection costs vary depending on various factors, but Rystad finds that on average, costs are $3.4/kcf, and $177 per metric ton of methane flaring avoided.[82] Costs associated with reinjection include between $0.20 and $0.60 per kcf for gathering and between $0.20 and $5.70 per kcf for storage, for a total cost between $0.40 to $6.30 per kcf.[83] This corresponds to a range of *$20 to $329 per metric ton of methane abated*. Reinjection is an effective option for sites flaring more than 350 kcf/day of gas.[84]

The information provided by Rystad demonstrates that there are multiple cost effective options to capture associated gas, including in circumstances where connection to a sales line is not technically or economically feasible.

3. *Pneumatic Controllers*

A. *EPA's Requirements are Reasonable and Based on the Existing State Requirements*

EPA established a zero-methane emissions standard for gas-powered pneumatic controllers. This approach to natural gas-driven pneumatic devices is a logical and cost-effective step that has been taken by jurisdictions and companies globally. For example:

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[75] *Id*. at 50–51.
[76] *Id*. at 51.
[77] *Id*. at 40.
[78] *Id*. at 40–41.
[79] *Id.* at 11.
[80] *Id*. at 56.
[81] *Id*.
[82] *Id.* at 11.
[83] *Id*. at 69.
[84] *Id*. at 40.

- **Colorado:** Since May 2021, the State of Colorado has prohibited the venting of gas-driven controllers at new and existing facilities. Additionally, Colorado required operators to convert specified portions of their facilities to be non-emitting by certain dates in 2022 and 2023. Colorado has proposed to expand its current rule to phase out all emitting controllers in the state, other than emergency shut-down devices, to implement the EPA emissions guidelines.[85]
- **New Mexico:** In 2022, New Mexico required that new pneumatic controllers and pumps be non-emitting, and also required an increasing proportion of existing controllers to be converted to non-emitting designs. Operators were required to convert a portion of their emitting pneumatics to non-emitting designs by Jan. 1, 2024, with further conversions required by 2027 and 2030. (The 2027 and 2030 provisions will effectively be pre-empted by US EPA's recent rules, which are more stringent in that time period. The 2022 rules also required measures to limit venting from existing pneumatic pumps.[86]
- **EU:** The rule prohibits venting other than during emergencies or malfunctions, and requires replacement of equipment that vents with non-emitting alternatives when commercially available.[87]

In addition, numerous companies have made commitments or taken action to switch over to zero-emitting controllers in recent years, including:

- **EQT:** The largest natural gas producer in the U.S. recently converted its entire fleet of natural gas-driven pneumatic controllers to zero-emitting devices in the span of approximately one-and-a-half years.[88]
- **Diamondback Energy:** Another U.S. producer, Diamondback energy has stated it anticipated replacement of "nearly all" of its controllers with zero-emitting controllers within four years.[89]
- **BP:** In comments submitted to EPA's then-proposed rule, BP stated it anticipated that over 95% of its wells in the Permian basin would use instrument air rather than natural-gas driven pneumatics by 2023.[90]

[85] Proposed Revisions to Regulation No. 7 (Nov. 5, 2024): https://drive.google.com/drive/u/0/folders/1Fe71uEPVEFPMT5bZncf2997cY1vPqEYd
[86] N.M. Code R. § 20.2.50.122.
[87]Regulation (EU) 2024/1787 of the European Parliament and of the Council of 13 June 2024 on the reduction of methane emissions in the energy sector and amending Regulation (EU) 2019/942, Article 15, Paras 2 and 5.
[88] *EQT Eliminate Nearly 9,000 Natural Gas-Powered Pneumatic Devices*, PRNewswire (Jan. 4, 2023) https://www.prnewswire.com/news-releases/eqt-eliminates-nearly-9-000-natural-gas-powered-pneumatic-devices-301713418.html (last accessed Feb. 3, 2024).
[89] Diamondback Energy, *2021 Corporate Sustainability Report* 8 (2021), https://www.diamondbackenergy.com/static-files/faf5ab25-5ab5-4404-8c04-c7bd387ae418.
[90] BP, *Comments on Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review*, 10 (January 31, 2022) (available at https://www.bp.com/content/dam/bp/country-sites/en_us/united-states/home/documents/who-we-are/us-advocacy/2022/bp%20Comments_EPA-HQ-OAR-2021-0317.pdf).

Collectively, such actions, both at the governmental and business levels, show that EPA's proposal to eliminate emissions that are associated with venting from pneumatic instruments and pumps is eminently feasible.

B. EPA's Standards are Based on a Suite of Availability of Multiple Technologies

EPA found that several technically feasible methods exist to eliminate emissions from natural gas-powered pneumatic controllers. The methods can be divided into two types:

- Solutions that do not emit hydrocarbons to the atmosphere because they are not powered by natural gas
- Solutions that capture hydrocarbon emissions from naturally-gas powered pneumatic controllers.

Within each of these broad categories, multiple options exist.[91]

Under the first approach-replacing natural gas-powered controllers with non-emitting alternatives- operators can use either electric controllers or instrument air systems. Electric controllers can be powered by grid electricity, solar, or on-site power generation. Instrument air systems use a compressor to increase the pressure of the air and can be powered by grid power or a generator.[92]

Alternatively, operators can eliminate methane emissions from natural-gas powered controllers by routing emissions to a process that achieves a 100% reduction in emissions or by operating the controller as a self-contained system. The former involves collecting and routing controller emissions to a sales line. The latter involves using a closed loop system to capture controller discharge emissions.

The number of options provides significant flexibility to operators to determine which approach to use at a particular facility.

C. EPA's Standards are Cost Effective

EPA estimated the cost effectiveness of five approaches that eliminate emissions from natural gas-powered pneumatic controllers. EPA did not have sufficient cost information to evaluate the costs or cost effectiveness of routing emissions to a process that achieves a 100% reduction in emissions or by operating the controller as a self-contained system. However, EPA still found that these options could eliminate methane emissions in certain circumstances based on facility-specific characteristics.[93]

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[91] Final TSD, 2.4.3.

[92] Id. EPA also noted that solar and nitrogen are "promising" technologies that can be used to power non-emitting controllers, but it did not have sufficient information to determine if either is adequately demonstrated or to estimate costs.

[93] Final TSD, 2.4.3.

For the five options EPA had available cost information, EPA examined each approach at three different model size plants. EPA found cost-effective equipment-type options for each size plant for production and midstream facilities.

- Electric controllers at sites with electricity are cost-effective for all facility size classifications with a range of $334-$449 per ton abated methane emissions.[94]
- Zero-bleed compressed air systems are cost-effective for all facilities with electricity for methane ($2,157/ton for small, $1232/ton for medium, $899/ton for large) and cost effective for large production facilities without electricity ($1,685/ton of methane) and small and large midstream facilities ($1,685/ton of CH4 and $679/ton of CH4, respectively).[95]
- Regardless of grid access, solar-powered controllers are the cheapest option for all facility size classifications. For methane, EPA estimates costs of $329/ton for the small production plant size, $281/ton for a medium production plant size, and $264/ton for the large production plant size for solar-powered controllers.[96] Electric controller installations powered by solar are cost-effective for all production and midstream facility size classifications with a range of $258-$329 per ton abated methane emissions
- Electric controllers powered by on-site generators are cost-effective for all facility size classifications with a range of $538-$1,384 per ton abated methane emissions.[97]
- Zero bleed compressed air systems that run on generators are expensive for small and medium production facilities ($4207 /ton of methane for small plant size, $2,233/ton of methane for medium plant size).[98] However, as noted above, other abatement options are cost effective at small and medium plant sizes.

D. *Independent report bolsters EPA's cost analysis by demonstrating cost-effectiveness by region.*

An independent report by Analysis Group assessing the costs to operate zero-emission technologies further demonstrates the cost-effectiveness of EPA's pneumatic controller proposal, with specific emphasis on the cost-effectiveness of these technologies by region, including the Midwest, Mid-Atlantic, South, Rocky Mountains, and Alaska.[99] The report concludes that, after incorporating electricity and net maintenance costs, all technologies considered (grid-connected, solar, and instrument air) are cost-effective at small, medium, and large plants in all regions, even when gas savings are not considered.[100] The report's findings supplement EPA's conclusions with its regional

[94] 87 Fed. Reg. at 16928, Table 19.
[95] *Id*.
[96] *Id*.
[97] *Id*.
[98] *Id*.
[99] *Analysis Group, Methane Reduction Technology Electricity and Abatement Costs: The Cost to Power Zero-Emission Pneumatic Controllers and Pumps in Grid-Connected and Remote Locations, at 17–18, 46 (May 6, 2022) [hereinafter Analysis Group Report] (included as Attachment C)*.
[100] *Id.* at 4.

focus and because it incorporates additional and varied cost factors. Some highlights of the report include:

- *Solar Controller Analysis Considers Regional Conditions, Particle Accumulation, and Large Solar Sites:* The report's solar controller evaluation accounts for a potential decrease in solar/storage output in colder climates[101] and due to particle accumulation on panels.[102] The model assumes ten days of energy storage at a maximum depth discharge of 80%.[103] Additionally, solar levelized costs were adjusted regionally based on differences in solar capacity factors.[104] Even after incorporating these variances into the model, the report finds that the installation of zero-emitting pneumatic controllers is cost-effective in each region, including Alaska, countering claims that facilities in colder and cloud-covered states cannot feasibly install solar-driven controllers and that particle accumulation makes solar infeasible. The report also considers oversizing the solar array and battery storage[105] to the extent necessary to ensure sufficient generation to power controllers. Based on these assumptions, in combination with its use of independent regional levelized costs of solar and storage, the report finds that large facilities are capable of using solar controller systems cost-effectively.
- *Consideration of Extra-Large Sites:* The report supplements EPA's analysis by considering extra-large sites. It considers sites with electricity demand reaching 2,000 kW by modeling an extra-large plant size of 200 controllers for production and transmission and storage sites,[106] and finds that nearly all technologies would be cost effective. This counters certain industry commenters' claims that zero-emitting technologies are not cost-effective at plants that are larger than EPA's model plants or at sites requiring 2,000 kW of electricity.
- *Adjusted Capital Expenditures:* The report's grid-powered, solar, and instrument air controller analyses all include adjusted capital expenditures for equipment, prepared independently of EPA's analysis.[107]
- *Maintenance Costs*: Unlike EPA's original analysis (but like the analysis for its supplemental proposal), the analyses for all three technologies incorporate net maintenance costs, which result in savings associated with replacing gas-driven controllers with zero-emitting controllers.[108]
- *Costs of Service Extension:* The report further supplements EPA's costs analysis by considering the costs for locations that do not have electricity supply on-site, but are located close enough to the local electric distribution system to consider developing a line extension from the closest spot on the

[101] *Id*. at 46.
[102] Analysis Group, *Methane Reduction Technology Electricity and Abatement Costs: Summary Presentation for EPA*, at 12 (May 10, 2022) [hereinafter Analysis Group Presentation] (included as Attachment D) at 12.
[103] Analysis Group Report*, supra* note 99, at 18.
[104] *Id*.
[105] *Id*. at 17.
[106] *Id*.
[107] Analysis Group Report, *supra* note 99, at 45–47.
[108] *Id*. at 45–47.

grid. The report finds that, in most situations, the cost of constructing a distribution line when an operator is 0.5 miles away from access plus electricity use results in cost-effective methane abatement.[109] While cost-effectiveness may decrease with more distance from the grid, this conclusion rebuts certain industry commenters' claims that the cost to obtain grid access is prohibitive.[110]

- *Electricity Costs:* The report's grid-powered and instrument air analyses consider electricity costs by region. The report estimates the cost of delivered electricity as the average of state prices for electricity to ultimate customers,[111] and finds that installation of zero-emitting pneumatic controllers would be cost-effective in all regions.[112]

IV. EPA's Methane Rule for Existing Sources is Economical, Even for Small Producers and Marginal Wells

EPA and EDF analysis demonstrate that technologies and practices that eliminate or reduce methane emissions from existing oil and gas sources are low cost and achievable, even for operators of marginal wells and small operators. EPA's carefully tailored approach that pairs the best system of emissions reduction ("BSER") to subcategories of sources based on the amount of pollution that such sources emit ensures an equitable application of the standards. We provide an example below for well sites.

1. *EPA's Marginal Well Analysis Demonstrates that Inspections are Economical for Marginal Wells*

EPA conducted an analysis to determine the impact of standards of performance on low producing wells-i.e., those producing less than 15 BOE per day or 90,000 cubic feet of natural gas per day or less.[113] For this analysis EPA created a marginal well financial analysis model. The model estimated single year profits and operating costs other than regulatory costs for oil and gas wells separately, assuming high, average, and low commodity prices. Per this model, all marginal oil wells at all production thresholds are profitable assuming low, average and high oil prices. For example, assuming low oil prices, even oil wells that produce less than 1 BOE/d yield a one-year net profit of $2,163.[114] Marginal wells in the highest production bracket, those producing between 12 and 15 BOE/d, are profitable at a rate of $189,598 annually, again assuming low oil prices.[115] Marginal gas wells are less profitable than oil wells, with the lowest producing wells (those producing less than 1 BOE/d being unprofitable

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[109] *Id*. at 23, 24–26.
[110] *See* Amer. Petroleum Inst., *Comments on EPA's Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review* 7–8 (Jan. 31, 2022), https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-0808 [hereinafter 2022 API Comments].
[111] Analysis Group Report, *supra* note 99, at 17.
[112] *Id*. at 24–26.
[113] 2023 TSD at Ch. 6.
[114] *Id*. at Table 6-5.
[115] *Id*.

before the addition of any regulatory costs. Marginal wells that produce between 1 and 15 BOE/d operate at a profit ranging from $538 to $36,444 per year, assuming average gas prices.[116]

EPA estimates that roughly 50-60% of existing well sites are wellhead only single-well sites. For operators of wellhead only oil sites, EPA's analysis demonstrates that the costs of conducting quarterly AVO inspections ($336-$630) is reasonable even for operators of the lowest producing oil wells, assuming low oil prices, as such inspection costs are roughly one-quarter of an oil well's profit. Under a high oil price scenario, the cost of conducting quarterly AVO inspections at oil wells producing less than 1 BOE/d is roughly one-eighth of a well's profit ($4,012). Owners of higher producing wells can easily afford quarterly AVO inspections as their profits range from $19,597 to $189,598 annually, assuming low oil prices. Profits are higher assuming average and high oil prices.

For operators of wellhead only gas sites, assuming average gas prices, quarterly AVO inspections are economical for operators that produce at least 2 BOE/d as such sites turn an annual profit of $4,609.[117] Under a high gas price scenario, all but the lowest producing gas wells can afford to conduct quarterly AVO inspections. Gas wells that produce at least 1 BOE/d yield an annual profit of $6,608, assuming high gas prices.

EPA's marginal well analysis demonstrates that quarterly AVO inspections are economical at all marginal oil wells, under a low, high or average price scenario. It further demonstrates that quarterly AVO inspections are economical for all but the lowest producing gas wells, under a high commodity price environment, and all marginal gas wells that produce at least 2 BOE/d under an average commodity price environment.

2. *EDF's Economic Analysis Supports EPA's Analysis*

EDF conducted its own economic analysis of the Methane Rule. This analysis further demonstrates the reasonableness of the rules, including as applied to owners of marginal wells.

EDF economists and third-party experts retained by EDF to evaluate EPA's cost estimates and analysis conclude that "EPA's analysis and conclusions are reasonable and well supported..."[118] These experts reviewed the Methane Rule (both the requirements for new sources and existing sources), Technical Support Document and Regulatory Impact Analysis. They also reviewed information regarding the production levels of new and existing wells, industry profits in 2021, 2022 and 2023, and EPA's estimate of total annualized compliance costs for the Methane Rule. Their review and analysis confirmed the reasonableness of EPA's estimate that the Methane Rule's total

[116] *Id*. at Table 6-4.
[117] *Id*.
[118] Decl. of Lucija Muehlenbachs, Lauren Beatty, and Maureen Lackner at 2, Opp. of Environmental and Health Respondent-Intervenors to industry Petitioners' Motion for Stay, Attachment E.

annualized compliance costs for new and existing owners and operators are estimated to represent just 0.5% of industry revenue:[119]

EPA's compliance cost projections are derived from reasonable cost estimates associated with each standard multiplied by the estimated number of sources that will be subject to those standards. In determining the costs of each standard, EPA relied on numerous data sources, including data from past federal and state rulemakings and, in many cases, industry supplied data.[120]

EDF's experts also agree that EPA's analysis of the costs of LDAR inspections and associated gas flaring rules "are reasonable and are based on reliable data from state regulators and industry."[121] Indeed, EDF estimates that "costs may be lower in reality than assumed by EPA,"[122] due in part to studies documenting that "compliance costs decline over time as operators learn how to comply at lower costs and as manufacturers ramp up production of equipment and devices."[123]

EDF's experts also agree with EPA that operators of existing wells will be able to absorb compliance costs. Based on an analysis of revenue and ownership profiles, EDF estimates that operators of these wells generated $608 billion in 2022, with a per operator average revenue of $53 million. In 2019 and 2021, the average per operator revenue for operators of existing sources was $24 million and $32 million, respectively.[124] EPA estimates that the total annualized compliance costs for the NSPS and Emissions Guidelines represent 0.5% of industry revenue,[125] accounting for gas savings. EPA does not separately evaluate compliance costs for the emissions guidelines. Nevertheless, the significant average revenues generated by owners of existing sources (nearly half a billion in the most recent year evaluated) indicates that the majority of them will be able to absorb compliance costs that represent less than 1% of their revenue.

A separate EDF analysis of the ownership of marginal wells reveals that the majority of such wells (three quarters) are owned and operated by companies who also own larger producing (and thus more profitable) wells.[126] Analysis of marginal well site ownership data shows that:[127]

- Fewer than 100 very large companies, (defined as owning over 1,000 operating well sites) dominate ownership of the nation's marginal well sites. These firms control nearly half of all marginal well sites and had average gross revenues of $1.8 billion in 2019.

[119] *Id*. at 3.
[120] *Id*. at 5.
[121] *Id*. at 6.
[122] *Id*. at 7.
[123] *Id*. at 9.
[124] *Id*. at 13
[125] 89 Fed. Reg. at 16,866.
[126] EDF, By the numbers: marginal oil and gas wells, https://blogs.edf.org/energyexchange/wpcontent/blogs.dir/38/files/2021/11/MarginalWellFactsheet2021v2.pdf
[127] EDF analysis of Enverus Prism oil and gas data and operator data for 2019.

- More than 3⁄4 of marginal well sites are owned by companies with more than 100 active wells who averaged gross revenues of nearly $335 million in 2019.
- Very small companies, or those with fewer than 10 operating sites, control just 4% of marginal well sites.

This analysis further demonstrates that existing well operators will be able to absorb the compliance costs associated with implementation of standards of performance for designated facilities.

V. EPA's Technology Neutral Standards Afford Industry with Substantial Flexibility to Determine How Best to Achieve each Pollution Reduction Standard

In addition to tying emissions control requirements to subcategories of existing sources, and thereby incorporating reasonable off ramps and exceptions into the final presumptive standards for existing sources, EPA's technology-neutral standards of performance allow operators to choose from a suite of available control technologies to meet requisite standards. This technology neutral approach is a hallmark of CAA Section 111 and affords industry significant flexibility in determining how to eliminate or control pollution from stationary sources. For example, the following is a non-exhaustive list of the multiple technologies and approaches operators can use to reduce emissions from existing sources:

- Pneumatic controllers. As discussed above, there are at least 5 cost effective, demonstrated methods available to eliminate emissions from pneumatic controllers to achieve EPA's zero methane emissions standard for this source.
- Oil wells with associated gas. EPA identified four abatement options operators can use to eliminate methane emissions from the venting of associated gas at oil wells that produce 40 tpy of more of methane emissions. Specifically, operators can route associated gas to a sales line, use the associated gas on-site as an alternative source of fuel, use the gas for another useful purpose that a purchased fuel, chemical feedstock or raw material would serve, or reinject it into the well or another well. Operators of oil wells that produce less than 40 tpy of methane emissions from associated gas may use any of these abatement options and may also flare the gas.
- Reciprocating compressors. Operators can elect to use one of the three following approaches to reduce emissions: (1) monitor and repair the rod packing to maintain a volumetric flow rate at or below 2 scfm per cylinder; (2) change out the rod packing every 8,760 hours of operation; or (3) route emissions to a control device or to a process.[128]
- Centrifugal compressors. EPA allows for the use of two options: (1) monitoring and repairing the compressor to maintain a volumetric flow rate at

[128] 89 Fed. Reg. at 16895.

or below 3 scfm per cylinder; or (2) routing emissions via a closed vent system to a control device or to a process.[129]

- Fugitive emissions. Operators may use a suite of technologies to conduct instrument inspections, where such inspections are required. Options include optical gas imaging cameras, Method 21 compliant devices, aerial surveys, continuous monitors, other approved advanced leak detection technologies, or a combination of such approaches. In some instances, operators need only conduct AVO inspections.[130]
- Storage tanks. Operators can use an efficient combustion device or vapor recovery unit to reduce emissions.

EPA developed each standard of performance after reviewing extensive information, and modeling multiple different technologies using a suite of model plants. The administrative record for this case includes two proposed rules: two technical support documents; a regulatory impact analysis; two response to comment documents—a separate one for the 2021 and 2022 proposal; and the final rule. The examples provided above for the pneumatic controller and oil well with associated gas requirements are two examples of EPA's extensive analysis of the costs and emissions reductions analysis the agency conducted when evaluating the best system of emissions reductions for each designated facility, and sub-facility category.

In addition to the built-in flexibilities of the rule stemming from EPA's subcategorization of sources and the technology-neutral performance standards, existing sources have a full five years to come into compliance from the date EPA promulgated the final rule.[131] This protracted compliance implementation timeline allows operators time to plan for retrofits or retire assets that are at the end of their useful economical life.

V. RULOF Provides Additional Flexibility but Broad Application will be Difficult to Demonstrate.

As demonstrated above, EPA's presumptive standards include cost effective and economical standards of performance for categories and subcategories of sources that are based on a suite of available and demonstrated technologies. The structure of the final standards thus accounts for differences in production and/or pollution potential and assigns costs accordingly. Compliance costs are economical, even for marginal wells. Additionally, Section 111(d) of the CAA and EPA's implementing regulations also allow states to depart from the presumptive standards in the EGs for an individual facility or class of facilities by invoking the remaining useful life and other factors (RULOF) exception.

1. *To establish less stringent performance standards for designated facilities, TCEQ must follow EPA's RULOF Provisions.*

[129] *Id*. at 17054.
[130] *Id*. at 16871.
[131] *Id*. at 17012.

Pursuant to this exception a state may apply a standard of performance to a designated facility that is less stringent than, or has a longer compliance deadline than, EPA's presumptive standard provided the state demonstrates that the facility or class of facilities "cannot reasonably achieve the degree of emission limitations determined by EPA" based on one of three factors:

(1) unreasonable cost of control resulting from plant age, location, or basic process design;
(2) physical impossibility or technical infeasibility of installing necessary control equipment; or
(3) other circumstances specific to the facility.[132]

Assuming one of these three factors is applicable to a particular existing source, a state must make the following demonstrations or conduct the following analysis.[133] First, it must demonstrate that there are fundamental differences between the information specific to a facility or class of facilities and the information EPA relied upon when determining the degree of emissions limitation achievable through application of the BSER, or compliance with a deadline, that makes achieving such degree of emissions limitation or deadline unreasonable. Second, standards of performance applied under the RULOF exception must be no less stringent, or have a compliance schedule no longer, than necessary to address the fundamental differences between the facility(s) claiming the exemption and the information EPA evaluated when setting the BSER or deadline. Third, the state must evaluate the systems of emission reduction identified in the emissions guidelines using the factors and evaluation metrics EPA considered. Fourth, a standard of performance must be in the same form as the standard finalized by EPA (i.e., a numeric standard or work practice standard). Lastly, if a standard of performance is based on an operational condition, such as a retirement date, this must be included in the state plan as a federally enforceable requirement.

RULOF's narrow applicability, combined with EPA's comprehensive evaluation of cost, emissions reductions, and availability of abatement technologies, for each of the existing sources covered by the emissions guidelines, strongly suggests that RULOF exceptions will not be widely available.

2. *Using the emissions guidelines for pneumatic controllers as an example, RULOF exceptions will be difficult to demonstrate.*

For example, with respect to pneumatic controller retrofits, we believe an exception from the presumptive standards would be difficult to demonstrate. As discussed above, EPA thoroughly analyzed multiple control options for a suite of facilities that contain emitting controllers. For production sites, EPA developed three model plants: small, medium and large. EPA assumed a certain number of emitting controllers at each plant and assigned emissions to each plant accordingly. EPA then evaluated three different types of control options to abate emissions at each model

[132] 40 C.F.R § 60.24a(e)(1).
[133] *Id*. at § 60.24a(e)(2).

plant: (1) an enhanced maintenance program for intermittent vent controllers; (2) routing the controller emissions to a control device; and (3) using non-gas-driven controllers or non-emitting systems. EPA evaluated the costs and any secondary air or other impacts expected from the use of each type of control option at each of its model plants to determine the BSER for pneumatic controllers. Notably, EPA evaluated the costs associated with the use of five different non-gas-driven controllers or non-emitting systems at each of its three model plants: (1) electric controllers powered by grid electricity; (2) electric controllers powered by solar power; (3) electric controllers powered by on-site generators; (4) instrument air driven controllers powered by grid electricity; and (5) instrument air driven controllers powered by on-site power generation.

A state seeking to apply an exception under RULOF to pneumatic controllers must demonstrate that there are fundamental differences between the information specific to a facility or class of facilities and the information EPA relied upon when determining the degree of emissions limitation achievable through application of the BSER, or compliance with a deadline, that makes achieving such degree of emissions limitation or deadline unreasonable. In addition, the state must evaluate the systems of emission reduction identified in the emissions guidelines using the factors and evaluation metrics EPA considered. Thus, in order to demonstrate that a particular pneumatic controller facility, or type of facilities, cannot achieve the BSER of zero methane emissions, the state would need to demonstrate that none of the five non-gas-driven controllers or non-emitting systems can be deployed at a reasonable cost, or that all of them are technically infeasible, that all of them are physically impossible, or must claim some other grounds specific to the facility. This will be challenging since EPA's model plant approach evaluated a suite of different facilities and also allows operators to choose from a multitude of cost-effective abatement options to achieve the standard of zero methane emissions.

VI. TCEQ Should Leverage Existing Programs and Substantial Resources for Technical and Financial Assistance to Facilitate Implementation of State Methane Standards.

We encourage TCEQ's OOOOc rule team to explore how TCEQ's existing programs can be paired with the protracted compliance implementation timelines for existing sources and historic levels of financial and technical assistance for operators. The agency can and should leverage these resources to facilitate permanent emissions reductions from end-of-life wells, focus public funds on operators in genuine need of assistance, and develop an efficient strategy for ensuring compliance with the new methane standards. Specifically, we suggest TCEQ evaluate:

- The Office of Water's Financial, Managerial, and Technical Assistance program as a model of customized assistance framework for operators facing challenges operating sound systems and complying with environmental protections. The FMT program offers free, onsite support and education on a wide variety of topics to assist operators of public water and wastewater systems; technical training workshops for operations staff; and managerial assistance with system design, funding help, and interacting with governments. TCEQ should collaborate with the recipients of $510 million in MERP funding for operators of marginal conventional wells and small operators to assess the financial, managerial and technical capabilities of their systems.[134]

- The Air Grants Division's New Technology Implementation Grant Program as pathway to offset cost of emissions reductions projects at oil and gas sources and incentivize prompt reductions ahead of compliance obligations. Since 2021, TCEQ has awarded nearly $10 million in grants to incentivize reductions in oil and gas emissions.[135] We urge Texas to sustain these incentive programs through continued state investment.[136] Further, TCEQ should look for opportunities to replicate or augment its NTIG program using the historic federal investments in our state's energy infrastructure, including, specifically projects funded by the Methane Emissions Reduction Program.
- Synergies and collaboration with the Texas Voluntary Marginal Conventional Plugging Program (TxMCW), newly created with a $134 million federal investment in Texas' oil and gas industry and impacted communities. For example, TCEQ could establish a referral program from the OOOOc rule team where operator stakeholders can learn about incentives to retire wells that are not expected to meaningfully produce but continue to be regulated as sources of air contaminants until properly plugged and abandoned, and therefore will have compliance obligations in 2029 if still unplugged.[137]
- Collaborative initiatives with the Office of Compliance and Enforcement to make the most of the extended compliance timeframe for existing sources including:
    - An assessment of previous regulatory initiatives like the implementation of protective regulations for the state's underground storage tank systems. OCE developed strategies to identify which of those systems were de facto out of service and required permanent removal and remediation and a correspondingly tailored enforcement process. Before compliance obligations attach to existing sources, TCEQ should seek opportunities to reduce the inventory of sources subject to the rule by identifying of end-of-life wells that ought to be plugged[138] which will also

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[134] Information developed through such a program could help TCEQ identify sources where a variance under RULOF may be appropriate, such as oil wells that produce a very low amount methane in their associated gas. *See* 89 Fed. Reg. at 16947.

[135] https://www.tceq.texas.gov/downloads/air-quality/terp/reports/reports-project-list-ntig.pdf

[136] Additional pathways exist to fund this or similar incentive programs, such as a custom or third party administered supplemental environmental project, for example.

[137] EPA and DOE awarded $350 million in financial assistance for voluntarily plugging and abandonment of marginal conventional wells based on the states' proportion of these low-producing wells, with Texas receiving the largest award. https://netl.doe.gov/node/13193. Preliminary analysis conducted by EDF indicates that approximately 30% of Texas' well inventory are idle wells, shut in for more than 12 months (and the majority thereof are unlikely to return to production) and approximately 49% of the state's wells produce less than 15 BOE per day, with about 60,000 producing less than one BOE per day.

[138] In response to comments about potential impacts to marginal wells, EPA found "marginal wells may continue to operate at low or negative profits rather than be shut-in and plugged due to a variety of reasons, including low

help identify sources that intend to continue to operate and may benefit from additional compliance assistance resources.

- Where appropriate, deploy targeted initiatives to address obstacles to future compliance for small operators. OCE has implemented similar programs to address systematic noncompliance issues, such as its Permian Basin Find It and Fix It initiative.
- Investing in oil and gas specific training for OCE staff, such as the TOP Energy Training program jointly administered by the University of Texas at Austin.

VI. Conclusion

We appreciate TCEQ's consideration of these comments and welcome the opportunity to discuss them and answer questions at TCEQ's convenience. We also encourage TCEQ to provide additional opportunities for stakeholder engagement as it proceeds with this rulemaking including by making a discussion draft of the proposed rule text and any proposed RULOF exceptions or frameworks available with as much time as practicable before formal publication in the Texas Register.

Respectfully submitted,

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operating costs, high plugging costs, low state bonding requirements, accounting practices, and tax credits available to the oil and gas industry." EPA, Response to Public Comments on the November 2021 Proposed Rule and the December 2022 Supplemental Proposed Rule at I-20-59 (Nov. 2023)