**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**

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| **Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review** | ) | **Docket No. EPA-HQ-OAR-2021-0317**<br><br>*Via regulations.gov*<br>*January 31, 2022* |

We submit these comments on behalf of Environmental Defense Fund (EDF), Clean Air Council, Clean Air Task Force, Center for Biological Diversity, Earthjustice, Earthworks, Environmental Integrity Project, Environmental Law & Policy Center, Food and Water Watch, Grand Canyon Trust, Natural Resources Defense Council, National Parks Conservation Association, Sierra Club, Southern Environmental Law Center, Waterkeeper Alliance, Western Environmental Law Center, Western Resource Advocates, and Wyoming Outdoor Council (together, "Joint Environmental Commenters"). Joint Environmental Commenters' comments are informed by the urgent need to reduce emissions of methane and other harmful pollutants from the U.S. oil and natural gas sector. Based on this critical scientific imperative, the Joint Environmental Commenters strongly support EPA's proposed regulations for new and existing sources, and we urge EPA to strengthen key provisions.

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## I. Introduction & Executive Summary

Joint Environmental Commenters submit the following comments on the Environmental Protection Agency's (EPA's) proposed rule to reduce emissions of greenhouse gases (GHGs) and other harmful air pollutants from the Crude Oil and Natural Gas Source Category under the Clean Air Act (CAA).[1] Joint Environmental Commenters share an interest in addressing the climate crisis through reductions in greenhouse gas emissions from the oil and gas sector. As a result, we greatly appreciate EPA's commitment to reducing oil and gas sector methane emissions and generally support EPA's proposed revisions to new source performance standards (NSPS) for GHGs and Volatile Organic Compounds (VOCs) for the Crude Oil and Natural Gas Source Category, the proposed emissions guidelines (EGs) for states, and the actions EPA proposes to take in response to the Joint Resolution of Congress adopted on June 30, 2021, pursuant to the Congressional Review Act (CRA). These comments highlight the portions of the proposal we support and detail areas where it must be further strengthened in order to meet the goal of achieving "action on a scale and at a speed commensurate with the need to avoid setting the world on a dangerous, potentially catastrophic, climate trajectory."[2]

Our comments are structured as follows:

- Background on the climate crisis and oil and gas associated environmental justice and public health impacts and the role of oil and gas operations in contributing to them.
- An overview of EPA's legal authority to regulate methane and VOCs for the oil and gas sector under Clean Air Act Section 111, and the effect of the June 30, 2021 CRA Resolution on that authority.
- Source-specific comments, including of the following: fugitive emissions monitoring; equipment and infrastructure sources including storage vessels, pneumatic controllers, compressors, liquids unloading, pneumatic pumps, and equipment leaks at gas processing plants; oil wells and associated gas, including venting and flaring; and potential standards for abandoned wells and pigging/blowdown events on pipelines.
- Impacts of standards and cost-benefit analyses, including using the social cost of methane and monetization of non-climate health impacts.

We begin with an overview of the current scientific consensus on the climate crisis, and a discussion of present and future impacts if significant global reductions in GHG emissions, including oil and gas methane emissions, do not occur in the immediate future. We believe that the urgency of the climate crisis compels a close look at the most recent peer-reviewed scientific

[1] We reserve the right to comment further and amend our comments upon publication of the supplemental proposal and regulatory text. Joint Environmental Commenters intend for all sources cited in this comment to be incorporated into the administrative record for this rulemaking. Sources cited in this comment have separately been sent to the EPA Docket Center for inclusion in Docket ID No. EPA–HQ–OAR–2021–0317. Attachments A-M to this comment are being uploaded with this comment to Docket ID No. EPA–HQ–OAR–2021–0317. Attachments N-BB to this comment will be separately uploaded to Docket ID No. EPA–HQ–OAR–2021–0317.

[2] Section 6(d), Executive Order 13,990 of January 20, 2021, Protecting Public Health and the Environment and Restoring Science To Tackle the Climate Crisis, 86 Fed Reg. 7,037 (Jan 25, 2021).

data and literature, virtually all of which demonstrates the immediate and devastating impacts of climate change which are already occurring and which will worsen dramatically if GHG pollution—including from the oil and gas sector—continues to rise. As President Biden has observed, "[t]he United States and the world face a profound climate crisis. We have a narrow moment to pursue action at home and abroad in order to avoid the most catastrophic impacts of that crisis."[3] The most recent Intergovernmental Panel on Climate Change ("IPCC") report details how the impacts of anthropogenic climate change already are being felt to an unprecedented and inexorably increasing degree, are irreversible over the course of generations, and will become magnified as GHG emissions continue to accumulate in the Earth's atmosphere.[4] Emissions increases, in addition to contributing directly to climate change-fueled drought, wildfire, flooding, and other catastrophic events, also lead to large-scale shifts in the earth's climate system known as tipping points, which exacerbate the effects of warming and make its consequences more difficult to address.[5]

The bottom line, which is borne out with increasing urgency and certainty by the accumulating weight of scientific data, is that:

- greenhouse gas emissions are making the Earth's climate hotter and more extreme;
- the harms inflicted on the biosphere by increasing temperatures are escalating, and the U.S. and the world must take immediate action to dramatically reduce GHG emissions to avoid catastrophic damage;
- these changes harm and further threaten human health, food supply, culture, and biodiversity;
- climate change causes ocean acidification; and
- these harms threaten the U.S. economy and national security.

Moreover, the human health impacts associated with oil and gas production are manifold and are not limited to the direct effects of climate change on human health. The activities that control climate change pollutants from oil and gas production activities also reduce emissions of other air pollutants. The oil and gas sector is a significant source of ozone-forming volatile organic compounds (VOCs) and hazardous air pollutants (HAPs) that not only adversely affect human health but disproportionately impact communities of color and low-income communities, the very populations highlighted in President Biden's call to prioritize environmental justice and "listen to the science."[6]

The harsh scientific realities of the climate crisis and the impacts of oil and gas sector pollution on human health make immediate emissions reductions imperative. Nowhere are such reductions more critical than in the context of methane, an extremely potent greenhouse gas that has both short and longer-term climate impacts far in excess of those of comparable volumes of CO2.

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[3] Section 6(d), Executive Order 13990 of January 20, 2021, Protecting Public Health and the Environment and Restoring Science To Tackle the Climate Crisis, Fed Reg. Vol. 86 No. 14.
[4] AR6 Summary for Policymakers (2021), at 6.
[5] USGCRP [U.S. Global Change Research Program], Climate Science Special Report: Fourth National Climate Assessment, Vol. I (Wuebbles, D.J. et al. eds.) (2017), https://science2017.globalchange.gov/downloads/CSSR2017_FullReport.pdf at 10 [hereinafter "USGCRP 2017"].
[6] EO 13,990 sec. 1.

Because of methane's disproportionate radiative forcing power, especially over the short-term, the reduction of anthropogenic methane emissions is one of the most cost-effective ways of tackling GHG emissions. According to the International Energy Agency, 45% of methane emissions from the oil and gas industry can be avoided at zero net cost.[7] Methane is truly the "low hanging fruit" of emissions reductions that are critical to avert the most catastrophic impacts of climate change on the human environment.

EPA's authority to reduce such emissions by the issuance of new source performance standards under Section 111 must consider and reflect what is "achievable through the application of the best system of emission reduction," (BSER) and nothing less. Moreover, as a result of the CRA resolution passed by Congress and signed by President Biden on June 30, 2021, EPA is precluded from issuing a new rule "that is substantially the same as" the 2020 Policy Rule.[8] Specifically, EPA may not issue a new rule that removes the transmission and storage sector from the oil and gas source category regulated under Section 111.[9]

We next provide specific feedback on the draft rule, including standards we strongly support along with highlighting areas in which EPA's proposed standards must be further strengthened. We discuss each of EPA's proposed standards for specific sources, and address topics for which EPA has solicited comment for a possible supplemental proposal.

- **Fugitive Emissions Monitoring**: EPA should require quarterly or more frequent optical gas imaging at all sites regardless of the site-level emission estimate, particularly if EPA retains its well-head only exemption. If EPA retains the tiered approach, it should exclude sites with failure-prone equipment from tiers subject to less frequent monitoring and should revise the potential to emit calculation to account for the well-documented existence of super-emitters. Covering smaller, leak-prone wells with frequent inspections is critical as our analysis shows that EPA's currently proposed one time only inspections at these well sites could reduce the overall effectiveness of its Leak Detection and Repair (LDAR) program by as much as half. At compressor stations, monthly monitoring should be required. EPA should also finalize an alternative standard that allows for screening with advanced technologies in combination with less frequent ground-based monitoring as long as equivalent emission reductions can be achieved. That alternative framework should likewise provide a pathway for continuous monitoring. Finally, EPA should finalize a community monitoring program that allows EPA to accept and use emissions data collected by third-parties.

- **Storage Vessels**: EPA's proposal to include tank batteries as affected facilities is a welcome revision. We also support EPA's new definition of modification for these sources. In determining what tanks or tank batteries are subject to the standards,

[7] IEA 2021 ("Methane emissions from oil and gas operations must be the first to go.")
[8] 5 U.S.C. § 801(b)(2).
[9] *See*, EPA, Congressional Review Act Resolution to Disapprove EPA's 2020 Oil and Gas Policy Rule (June 30, 2021), https://www.epa.gov/system/files/documents/2021-07/qa_cra_for_2020_oil_and_gas_policy_rule.6.30.2021.pdf.

EPA should base any applicability threshold on the affected facility's actual uncontrolled emissions. To the extent EPA retains a potential to emit approach based on legally and practicably enforceable limits, we support using the factors stated by EPA. However, if using a potential to emit approach EPA should revise the applicability threshold downward as leading states like Colorado have done.

- **Pneumatic Controllers**: EPA should finalize its zero-emission controller standard as proposed, with the exception of the functional need exemption currently proposed for processing plants. If EPA includes an exemption, the exemption should require that operators pursue secondary control options to reduce emissions to the greatest extent possible and provide clear justification for the technology implemented.

- **Liquids Unloading**: EPA should finalize a standard of zero emissions for liquids unloading events and should consider affected facilities any site that undergoes liquids unloading. EPA should require rigorous documentation of all liquids unloading events, and should set forth clear best practices that must be followed in limited situations in which liquids unloading cannot be conducted with zero emissions.

- **Compressors**: EPA should reduce the rod packing replacement threshold for reciprocating compressors based on annual monitoring from 2 scfm to 0.5 scfm. EPA should consider standards to reduce emissions from compressor exhaust and from dry seal centrifugal compressors.

- **Pneumatic Pumps**: EPA should set a zero-emission standard for pumps across the source category. If it includes a functional need exemption, the exemption's design should mirror that of pneumatic controllers.

- **Leaks at Processing Plants**: We support EPA's proposal to require bimonthly monitoring for leaks from pumps, valves, and connectors, as well as EPA's proposal to eliminate the "in VOC service" distinction. EPA should extend monitoring requirements to equipment designated with no detectable emissions.

- **Associated Gas at Oil Wells**: EPA should adopt performance standards that would eliminate the wasteful and unnecessary practice of disposing of associated gas through routine flaring. Specifically, EPA should determine that the BSER for emissions from associated gas during production is to capture and sell, productively use or reinject the gas. With respect to completions, we urge EPA to set performance standards that would eliminate venting throughout the flowback process except in case of narrowly-defined emergency; and eliminate flaring except in case of emergency or if necessary for pressure test purposes.

- **Abandoned Wells**: EPA should take steps to prevent wells from being improperly abandoned and orphaned by requiring operators to develop and comply with closure

plans. EPA should also work with states to identify wells at high risk of abandonment and develop solutions.

- **Pigging and Blowdowns**: EPA should include proposed performance standards and emission guidelines for pigging and blowdown activities on gathering pipelines in its supplemental proposal, and should consider proposing such standards for transmission pipelines as well. EPA should continue to coordinate with PHMSA to ensure comprehensive oversight of pipeline methane emissions across agencies.

With respect to the proposed section 111(d) emission guidelines for existing sources, Joint Commenters support EPA's general approach of designating the same best systems of emission reduction for existing sources as the agency designated for new sources. We also support EPA's requirement that states conduct rigorous outreach to affected communities as they develop their state plans, which will help ensure that those most harmed by oil and gas pollution have a meaningful opportunity to make their voices heard and influence the process. We agree with EPA's decision to grant existing sources no more than two years to come into compliance with applicable performance standards after state plans are finalized, but urge the agency to consider a faster implementation schedule. Furthermore, we advise EPA to establish clear limits and parameters on the situations in which states may grant a compliance variance to individual sources under section 111(d)'s "remaining useful life" provision.

Finally, Joint Environmental Commenters support the use of the Interagency Working Group's (IWG) February 2021 Social Cost of Methane interim value established pursuant to Executive Order 13009 and the incorporation of a global, rather than merely domestic, perspective on the costs of methane pollution. We wholeheartedly agree with these approaches, and provide input and suggestions for strengthening EPA's regulatory impact analysis, which ultimately understates the economic benefits of the Proposal, including the health benefits of reducing volatile organic compound emissions and other local air pollution, and underestimates the true costs of methane emissions.

We appreciate this opportunity to comment on EPA's proposal. We likewise appreciate the thorough and careful work that has gone into the proposal thus far, and proffer the enclosed suggestions for improvement with the end-goal of maximizing emissions reductions to the greatest extent possible consistent with EPA's legal authority.

## II. Background

### A. Climate Change Is an Existential Threat to Humanity.

#### 1. *Scientific Evidence Overwhelmingly Demonstrates that Climate Change is Already Causing Immediate, Devastating Impacts on Communities and These Harms Will Worsen Dramatically as Greenhouse Gas Pollution Continues to Rise.*

The urgency of the climate crisis, and the impact of human activities on global warming, is clear. As the Intergovernmental Panel on Climate Change ("IPCC") stated in its most recent report (AR6), "Human influence has warmed the climate at a rate that is unprecedented in at least the last 2000 years."[10] Climate impacts are already being felt across the U.S. and the globe, and while "[m]any changes due to past and future greenhouse gas emissions are irreversible for centuries to millennia,"[11] extreme weather events are projected to be "larger in frequency and intensity with every additional increment of global warming."[12] As the U.S. Global Change Research Program (USGCRP)—a federal program in which the EPA participates along with NASA, NOAA, the National Science Foundation, and others—has concluded "evidence of human-caused climate change is overwhelming and continues to strengthen," "the impacts of climate change are intensifying across the country," and "climate-related threats to Americans' physical, social, and economic well-being are rising."[13] In its Fourth National Assessment, the USGCRP found that "there is no convincing alternative explanation" for the observed warming of the climate over the last century other than human activities.[14]

The following section discusses the established and mounting scientific evidence demonstrating that climate harms are tangible, current, and will increase unless GHG emissions, including methane, are curbed dramatically. To put their findings in context, scientific reports often express the extent of scientific understanding of key findings by means of clearly defined metrics expressing the degree of confidence in those findings.[15] Where the following discussion uses these metrics, it presents them in italics.

2. *Greenhouse gas emissions are making the Earth's climate hotter and more extreme.*

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[10] AR6 Summary for Policymakers (2021), at 6

[11] *Id.* at 21, B.5.

[12] *Id.* at 18.

[13] Jay, A., D.R. Reidmiller, C.W. Avery, D. Barrie, B.J. DeAngelo, A. Dave, M. Dzaugis, M. Kolian, K.L.M. Lewis, K. Reeves, and D. Winner, Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II (Reidmiller et al. eds.) (2018), Ch. 1 at 36, doi: 10.7930/NCA4.2018.CH1 [hereinafter "USGCRP 2018"].

[14] USGCRP [U.S. Global Change Research Program], Climate Science Special Report: Fourth National Climate Assessment, Vol. I (Wuebbles, D.J. et al. eds.) (2017), https://science2017.globalchange.gov/downloads/CSSR2017_FullReport.pdf at 10 [hereinafter "USGCRP 2017"].

[15] The USGCRP communicates the extent of scientific understanding of its key findings with two metrics: "confidence", and "likelihood." Confidence is defined as "the validity of a finding based on the type, amount, quality, strength, and consistency of evidence (such as mechanistic understanding, theory, data, models, and expert judgment); the skill, range, and consistency of model projections; and the degree of agreement within the body of literature." The scale is *very high confidence* (strong evidence and high consensus), *high confidence* (moderate evidence and medium consensus), *medium confidence* (suggestive evidence and competing schools of thought), and *low confidence* (inconclusive evidence and disagreement or lack of expert opinion). Likelihood is defined as the "probability of an effect or impact occurring," and is "based on measures of uncertainty expressed probabilistically … e.g., resulting from evaluating statistical analyses of observations or model results or on expert judgment." The scale is *virtually certain* (99 to 100 percent likelihood), *extremely likely* (95 to 100 percent likelihood), *very likely* (90 to 100 percent likelihood), *likely* (66 to 100 percent likelihood), *about as likely as not* (33 to 66 percent likelihood), unlikely (0 to 33 percent likelihood), *very unlikely* (0 to 10 percent likelihood), *extremely unlikely* (0 to 5 percent likelihood), and *exceptionally unlikely* (0 to 1 percent likelihood). USGCRP 2017 at 6, 7.

According to the 2020 Annual National Climate Report from the National Oceanic and Atmospheric Association ("NOAA"), 2020 was the fifth-warmest year on record, with an average annual temperature about 2.4 degrees Fahrenheit hotter than the 20th century average.[16]
The 2020 data confirms a warming trend that has accelerated in recent years and decades. In fact, over the last 126 years, the five warmest years in the contiguous U.S. have all occurred since 2012.[17] Moreover, "[e]ach of the last four decades has been successively warmer than any decade that preceded it since 1850." [18] The IPCC also reported with *high confidence* that "[g]lobal surface temperature has increased faster since 1970 than in any other 50-year period over at least the last 2000 years."[19]

The U.S. is expected with *high confidence* to warm by an additional 2.5°F, on average, over the next few decades.[20] Daily highs are likewise projected with *very high confidence* to increase. [21] Under business as usual, the hottest days of the year could be at least 5°F (2.8°C) warmer in most areas by mid-century and 10°F (5.5°C) by late this century. [22] The urban heat island effect — which is expected with *high confidence* to strengthen as urban areas expand and become denser—will amplify climate-related warming even beyond those dangerous increases. [23]

Not only is the climate warming overall, extreme weather events are becoming more intense, dangerous, and frequent. The 2020 U.S. Climate Extremes Index[24] was the seventh highest on record in over 110 years, with an index 80 percent above average.[25] As the most recent IPCC report explained:

> Many changes in the climate system become larger in direct relation to increasing global warming. They include increases in the frequency and intensity of hot extremes, marine heatwaves, heavy precipitation, and, in some regions, agricultural and ecological droughts; an increase in the proportion of intense tropical cyclones; and reductions in Arctic sea ice, snow cover and permafrost.[26]

Human activities have contributed to the upward trend in North Atlantic hurricane activity since the 1970s (*medium confidence*).[27] In a 2020 study, researchers from NOAA and the University of

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[16] National Oceanic and Atmospheric Association, National Centers for Environmental Information, National Climate Report, 2020 Annual, "Temperature and Precipitation Analysis" https://www.ncdc.noaa.gov/sotc/national/202013.
[17] *Id.*
[18] IPCC AR6, Summary for Policymakers at 5, A.1.2.
[19] *Id.* at 8, A.2.2.
[20] USGCRP 2017 at 11.
[21] *Id.* at 185.
[22] *Id.* at 197.
[23] *Id.* at 17; IPCC AR6, Summary for Policymakers, at 25, C2.6. In addition, expanding urban areas and populations will also increase precipitation in and near cities (*medium confidence*). IPCC AR6, Summary for Policymakers, at 25, C2.6.
[24] "The USCEI is an index that tracks extremes (falling in the upper or lower 10 percent of the record) in temperature, precipitation, drought and landfalling tropical cyclones across the contiguous U.S." NOAA, 2020 Annual National Climate Report, "Other Notable Extremes," https://www.ncdc.noaa.gov/sotc/national/202013.
[25] *Id.*
[26] IPCC AR6, Summary for Policymakers at 15, B.2.
[27] USGCRP 2017 at 257.

Wisconsin Madison estimated that hurricanes and tropical cyclones have become about 5% more likely to reach "major" hurricane status in each successive decade since 1979.[28] The 2020 hurricane season, for example, broke or tied several records. With 13 hurricanes and six major hurricanes, 2020 had the second most hurricanes and major hurricanes on record, behind 2005, [29] the year that Hurricane Katrina devastated New Orleans. 2020 also tied for the largest number of Category 4 and 5 hurricanes in the Atlantic. [30] Climate change is projected to continue to increase hurricane intensity, making hurricanes more destructive by fueling higher wind speeds and more rainfall.[31] A 2016 study suggests the average intensity of Atlantic hurricanes will increase 1.8 to 4.2 percent by the 2080s, compared to a 1981 to 2000 baseline.[32]

Adding to increases in hurricane intensity, there is *very high confidence* that sea level rise will make coastal floods more frequent and severe during storms.[33] For example, the rise in sea levels also increased the height of flooding during Hurricane Sandy from 7.5 to 9.2 feet (2.3 to 2.8 meters).[34] Combined with sea level rise, more intense hurricanes could result in a median increase in storm surge from 25 to 47 percent along the U.S. Gulf and Florida coasts.[35]

In the recent AR6, the IPCC found with *high confidence* that, in 2016, global sea level rise occurred at the fastest rate "since 1900 than over any preceding century in at least the last 3000 years."[36] Global average sea level rose by seven to eight inches between 1900 and 2017, and the rate of sea level rise is accelerating.[37] Global sea level is likely to rise by 1.0 to 4.3 feet by the end of the century relative to the year 2000, with sea level rise of 8.2 feet possible.[38] Sea level rise is already making flooding more likely. For instance, since the 1960s, sea level rise has contributed to a 5- to 10-fold increase in minor tidal floods along the U.S. coast (*very high confidence*), which are expected to become more frequent, deeper, and wider in extent as sea levels continue to rise (*very high confidence*).[39] The IPCC forecasts with *high confidence* that flooding will become more likely in coastal cities due to "the combination of more frequent extreme sea level events (due to sea level rise and storm surge).[40]

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[28] James P. Kossina,1, Kenneth R. Knappb, Timothy L. Olanderc, & Christopher S. Veldenc, Global increase in major tropical cyclone exceedance probability over the past four decades, 117:22 Proceedings of the National Academy of Sciences, 11975-11980 (Jun 2020), DOI: 10.1073/pnas.1920849117, https://www.pnas.org/content/117/22/11975.
[29] NOAA, 2020 Annual National Climate Report, "Other Notable Extremes," https://www.ncdc.noaa.gov/sotc/national/202013.
[30] *Id.*
[31] USGCRP 2017 at 257.
[32] Balaguru, K., *et al*., Future Hurricane Storm Surge Risk for the U.S. Gulf and Florida Coasts Based on Projections of Thermodynamic Potential Intensity, 138 CLIMATIC CHANGE 99 (2016), https://link.springer.com/article/10.1007%2Fs10584-016-1728-8.
[33] USGCRP 2017 at 27.
[34] Lin, N., et al., Hurricane Sandy's Flood Frequency Increasing from Year 1800 to 2100, 113 PNAS 12071 (2016), www.pnas.org/content/113/43/12071.
[35] Balaguru *et al.* 2016.
[36] IPCC AR6, Summary for Policymakers, at 8, A.2.4.
[37] USGCRP 2017 at 339.
[38] *Id.* at 25-26, 333, 343.
[39] *Id.* at 333.
[40] IPCC AR6, Summary for Policymakers, at 25, C2.6.

Heavy precipitation has likewise become more frequent and intense in most regions of the U.S. since 1901 (*high confidence*),[41] even as average annual precipitation has decreased in some regions (*medium confidence*).[42] This finding is consistent with the scientific understanding that more water vapor is available to fuel extreme rain and snowstorms as the world warms (*medium confidence*).[43] Recent studies of Hurricane Harvey[44] and the 2016 flood in south Louisiana[45] concluded that climate warming made the record rainfall totals of both disasters more likely and intense. According to a 2020 study, the best estimate of the direct economic costs of Hurricane Harvey that are attributable to human-caused climate change is $67 billion.[46] Importantly, this estimate excludes other damages that are less easily measured, including mortality, morbidity, and temporary or permanent dislocations resulting from Hurricane Harvey.

Just like other climate change impacts, precipitation, both very wet and very dry, events will also get more extreme with additional warming (*high confidence*).[47] Under continued high GHG emissions, most U.S. regions are projected to experience two to three times more extreme precipitation events by the end of the century than they do now.[48] Rainfall during hurricanes making landfall in the eastern U.S. could also increase by 8 to 17 percent over the next century, compared to 1980-to-2006 levels.[49] Even under deep emission reductions scenarios that keep global warming to within 1.5°C, AR6 finds that "heavy precipitation and associated flooding are projected to intensify and be more frequent in most regions in Africa and Asia (*high confidence*), North America (*medium to high confidence*) and Europe (*medium confidence*)."[50] With 2°C or more of global warming, changes in droughts and heavy and mean precipitation will be even more dramatic.[51]

Climate warming also has exacerbated recent historic droughts and western U.S. wildfires by reducing soil moisture and contributing to earlier spring melt and reduced water storage in snowpack (*high confidence*).[52] In the continental western U.S., human-caused climate change

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[41] *Id.* at 20.
[42] *Id.* at 207.
[43] *Id.* at 214.
[44] Frame, D, M. Wehner, I. Noy & S. Rosier, The economic costs of Hurricane Harvey attributable to climate change, Climatic Change 160, 271-281 (Apr. 8, 2020), https://doi.org/10.1007/s10584-020-02692-8 ; Emanuel, K., Assessing the Present and Future Probability of Hurricane Harvey's Rainfall 2017, 114 PNAS EARLY EDITION (2017), www.pnas.org/cgi/doi/10.1073/pnas.1716222114; Risser, M.D. and M.F. Wehner, Attributable Human-induced Changes in the Likelihood and Magnitude of the Observed Extreme Precipitation During Hurricane Harvey, 44 GEOPHYS. RES. LETT. 12,457 (2017), doi: 10.1002/2017GL075888; van Oldenborgh, G.J. *et al*., Attribution of Extreme Rainfall from Hurricane Harvey, 12 ENVIRON. RES. LETT. 124009 (2017), https://doi.org/10.1088/1748-9326/aa9ef2.
[45] van der Wiel, K., *et al*., Rapid Attribution of the August 2016 Flood-inducing Extreme Precipitation in South Louisiana to Climate Change, 21 HYDROL. EARTH SYST. SCI. 897 (2017), www.hydrol-earth-syst-sci.net/21/897/2017/.
[46] Frame et al.
[47] IPCC AR6 at 19, B.3.2.
[48] USGCRP 2017 at 218.
[49] Wright, D.B., *et al*., Regional climate model projections of rainfall from U.S. landfalling tropical cyclones, 45 CLIM. DYN. 3365 (2015), https://link.springer.com/article/10.1007%2Fs00382-015-2544-y.
[50] IPCC AR6, Summary for Policymakers, at 24, C2.2.
[51] *Id.* at 24, C2.3.
[52] USGCRP 2017 at 231.

accounted for more than half of observed increases in forest fuel aridity from 1979 to 2015.[53] Drying of forest fuels has helped increase the number of large fires (*high confidence*) and has contributed to a doubling in fire area since the early 1980s.[54] The risk of severe wildfire in Alaska has likely increased by 33 to 50 percent because of climate change.[55] One model suggests that anthropogenic climate change may have quintupled the risk of extreme vapor pressure deficit (a measure of atmospheric moisture) in the western U.S. and Canada in 2016, increasing the risk of wildfire.[56] While the eastern U.S. experienced above-average annual precipitation in 2020—with the second- and third-wettest years on record in North Carolina and Virginia, respectively—the western U.S. suffered from below-average precipitation.[57] For example, in two western states, Nevada and Utah, 2020 was the driest year on record, and two other western states experienced their second-driest year in 2020.[58] The dryness in the west has contributed to 2020 being "the most active wildfire year on record (1983 to present) across the West," with nearly 10.3 million acres consumed.[59] California experienced its largest wildfire season on record, with approximately 4% of the state's land consumed by fire.[60] A 2021 study that examined wildfire risk in the Sierra Nevada found that, relative to a 2011-2020 baseline, the number of fires will increase by more than 20% and burned area will increase by at least 25% through the 2040s.[61] In 2020, Colorado experienced the three largest wildfires in its history.[62]

Higher warming also increases the probability and frequency of compound events, such as concurrent heatwaves and droughts, in many regions. [63] For example, the Fourth National Climate Assessment concluded with *very high confidence* that large-scale shifts in the climate system, also known as tipping points, and the compound effects of simultaneous extreme climate events have the potential to create unanticipated, and potentially abrupt and irreversible, "surprises" that become more likely as warming increases.[64] Moreover, the IPCC concludes that "[i]f global warming increases, some compound extreme events with low likelihood in past and current climate will become more frequent, and there will be a higher likelihood that events with increased intensities, durations and/or spatial extents unprecedented in the observational record will occur (*high confidence*)."[65] The crossing of tipping points could result in climate states wholly outside human experience and result in severe physical and socioeconomic impacts.[66]

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[53] *Id.* at 243.
[54] *Id.*
[55] *Id.* at 244.
[56] Tett, S.F.B., *et al*., Anthropogenic Forcings and Associated Changes in Fires Risk in Western North America and Australia During 2015/16, 99 BAMS S60 (2018), https://journals.ametsoc.org/view/journals/bams/99/1/bams-d-17-0096.1.xml.
[57] NOAA, National Climate Report, 2020 Annual, "Temperature and Precipitation Analysis" https://www.ncdc.noaa.gov/sotc/national/202013
[58] *Id.*
[59] NOAA, 2020 Annual National Climate Report, "Other Notable Extremes".
[60] *Id.*
[61] Gutierrez, A., S. Hantson, B. Langenbrunner, B. Chen Y. Jin, M.L. Goulden, & J.T. Randerson, Wildfire response to changing daily temperature extremes in California's Sierra Nevada, 7:47 Science Advances (Nov. 17, 2021), DOI: 10.1126/sciadv.abe6417.
[62] NOAA, 2020 Annual National Climate Report, "Other Notable Extremes".
[63] IPCC AR6, Summary for Policymakers, at 25, C2.7
[64] USGCRP 2017 at 411-23.
[65] *Id.* at 26, C3.3.
[66] USGCRP 2017 at 411.

The disastrous effects of compound extreme events are, in fact, already occurring. In AR6, the IPCC also makes clear that, since the 1950s, anthropogenic emissions have *likely* "increased the chance of compound extreme events," including "increases in the frequency of concurrent heatwaves and droughts on the global scale (*high confidence*), fire weather in some regions of all inhabited continents (*medium confidence*), and compound flooding in some locations (*medium confidence*)."[67] In 2020 and 2021, for example, record heat waves across the West combined with extremely dry conditions to create two of the worst wildfire seasons on record.[68] NOAA estimates the cost of the California, Washington, and Oregon "firestorms" alone resulted in nearly 50 deaths and cost over $17 billion. [69] Similarly, sea level rise, abnormally high ocean temperatures, and high tides combined during Hurricane Sandy to intensify the storm and associated storm surge, and an atmospheric pressure field over Greenland steered the hurricane inland to an "exceptionally high-exposure location."[70]

### B. Recent scientific studies confirm that climate change harms are escalating and that the U.S. must take immediate action to rapidly reduce greenhouse gas pollution to avoid catastrophic damages.

Recent studies have reiterated the vast and escalating harms wrought by climate change and the disproportionate harms suffered by communities of color and low-income communities. This section summarizes key findings from several of the most prominent recent reports: the Fourth National Climate Assessment prepared by hundreds of scientific experts and reviewed by the National Academy of Sciences, NOAA, NASA and many other federal agencies; the IPCC's AR6, released in August 2021; and the EPA's September 2021 report "Climate Change and Social Vulnerability in The United States: A Focus on Six Impacts."[71] While there are numerous other reports and studies from these and other institutions (many of which are referenced in these comments), we focus on these three here to emphasize that the longstanding scientific consensus regarding climate harms continues to strengthen, and that the severity of climate harms will only continue to increase without drastic steps to reduce GHG emissions.

First, the Fourth National Climate Assessment, which comprises two volumes from 2017-2018, makes clear that climate change harms will be long-lived, and the choices we make now to reduce greenhouse gas pollution will affect the severity of the climate change damages in the coming decades and centuries: "[t]he impacts of global climate change are already being felt in the United States and are projected to intensify in the future—but the severity of future impacts will depend largely on actions taken to reduce greenhouse gas emissions and to adapt to the changes that will

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[67] IPCC AR6, Summary for Policymakers, at 9, A.3.5.
[68] NOAA, Billion-Dollar Weather and Climate Disasters, https://www.ncdc.noaa.gov/billions/events/US/1980-2021 (accessed Dec. 10, 2021) ("The combined drought and heat also assisted in drying out vegetation across the West that contributed to the Western wildfire potential and severity.")
[69] *Id.*
[70] USGCRP 2017 at 416.
[71] U.S. Envt'l Protection Agency, Climate Change and Social Vulnerability in the United States (2021), available at https://www.epa.gov/system/files/documents/2021-09/climate-vulnerability_september-2021_508.pdf [hereinafter "EPA Climate & Social Vulnerability Report"].

occur."[72] While "[i]t is very likely that some physical and ecological impacts will be irreversible for thousands of years, while others will be permanent,"[73] the report also explains that "[m]any climate change impacts and associated economic damages in the United States can be substantially reduced over the course of the 21st century through global-scale reductions in greenhouse gas emissions."[74] The report also emphasizes that, without "significant global mitigation efforts, climate change is projected to impose substantial damages on the U.S. economy, human health, and the environment."[75] Specifically, with "high emissions and limited or no adaptation, annual losses in some sectors are estimated to grow to hundreds of billions of dollars by the end of the century."[76]

Despite pledges at global climate summits, the "Production Gap Report 2021" facilitated by the U.N. Environment Programme has found that "the world's governments still plan to produce more than double the amount of fossil fuels in 2030 than would be consistent with limiting global warming to 1.5°C."[77] Preventing the worst impacts of climate change "requires steep and sustained reductions in fossil fuel production and use" in addition to measures that reduce production-cycle emissions.,.[78] Reducing methane emissions from oil and gas production is an important component in the U.S. government's strategy to "tackle the climate crisis,"[79] but "minimizing methane emissions from fossil fuel extraction and distribution alone is not a substitute for a rapid wind-down in fossil fuel production itself."[80] Alongside reducing methane pollution, governmental actors must take separate steps to accelerate a rapid, just, and equitable transition to clean sources of energy, in line with the Paris Agreement's temperature limits.[81]

Second, even more recently, the IPCC's August 2021 AR6 paints a staggering and terrifying picture of a climate-destabilized future absent urgent and aggressive carbon emission reductions. For instance, the report confirms that "[h]uman-induced climate change is already affecting many weather and climate extremes in every region across the globe," and evidence demonstrating the link between human GHG emissions and "changes in extremes such as heatwaves, heavy precipitation, droughts, and tropical cyclones . . . has strengthened since" the prior IPCC report.[82] Based on current evidence, "[i]t is *virtually certain* that hot extremes (including heatwaves) have become more frequent and more intense across most land regions since the 1950s, while cold

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[72] Jay et al. In USGCRP 2018 at 34.
[73] Martinich, J., B.J. DeAngelo, D. Diaz, B. Ekwurzel, G. Franco, C. Frisch, J. McFarland, and B. O'Neill, 2018: Reducing Risks Through Emissions Mitigation. In Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, pp. 1346–1386. doi: 10.7930/NCA4.2018.CH29 at 1347.
[74] *Id.*
[75] *Id.*
[76] *Id*.
[77] SEI, IISD, ODI, E3G, and UNEP, (2021), The Production Gap Report 2021, at 1. http://productiongap.org/2021report.
[78] *Id.*
[79] Executive Office of the President, Executive Order 13990, Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis, 86 Fed. Reg. 7037 (Jan 25, 2021).
[80] SEI, IISD, ODI, E3G, and UNEP, (2021), The Production Gap Report 2021, at 5. http://productiongap.org/2021report.
[81] *Id.* at 6.
[82] IPCC AR6, Summary for Policymakers, at 8, A.3.

extremes (including cold waves) have become less frequent and less severe, with *high confidence* that human-induced climate change is the main driver of these changes." [83] Moreover, certain "hot extremes observed over the past decade would have been *extremely unlikely to occur* without human influence on the climate system."[84] In addition to exacerbating extreme weather, "[h]eating of the climate system has caused global mean sea level rise through ice loss on land and thermal expansion from ocean warming." Increasing sea level rise is caused in part by the rate of ice-sheet loss globally, which quadrupled between the 1990s and 2010s.[85]

Looking to the future, AR6 reports that, although "[g]lobal surface temperature will continue to increase until at least mid-century under all emissions scenarios considered," "[g]lobal warming of 1.5°C and 2°C will be exceeded during the 21st century unless deep reductions in CO2 and other greenhouse gas emissions occur in the coming decades."[86] Cutting GHG emissions now is critical because "there is a near-linear relationship" between human-caused GHG emissions and related global warming, meaning that each additional increment of global warming exacerbates changes in extreme weather events. For example, the IPCC reports that "every additional 0.5°C of global warming causes clearly discernible increases in the intensity and frequency of hot extremes, including heatwaves (*very likely*), and heavy precipitation (*high confidence*), as well as agricultural and ecological droughts in some regions (*high confidence*)." [87] Globally, the IPCC forecasts that each additional 1°C of global warming will cause about a 7% increase in the intensity of extreme daily precipitation events (*high confidence*).[88] Based on this demonstrated relationship, the IPCC concludes that "reaching net zero anthropogenic CO2 emissions is a requirement to stabilize human-induced global temperature increase at any level." [89] In order to limit global warming to a specific temperature level, global, cumulative CO2 would need to be kept within a discrete carbon budget.[90]

Third, the EPA's September 2021 report "Climate Change and Social Vulnerability in The United States: A Focus on Six Impacts" finds that, within the United States, communities of color and low-income communities are at increased risk of climate-driven harms compared to other communities. [91] For instance, "Black and African American individuals are 40-59% more likely than non-Black and non-African American individuals to currently live in . . . areas with the highest projected increases in temperature mortality from climate-driven changes in extreme temperatures."[92] The report also found that, with 2°C of warming, "Hispanic and Latino individuals are 43% more likely than non-Hispanic and non-Latino individuals to live" in areas that have "the highest projected labor hours losses due to climate-driven increases in high-temperature days."[93] Indigenous individuals are similarly 37% more likely to live in these high-

[83] *Id.* at 8, A.3.1.
[84] *Id.* at 8, A.3.1.
[85] *Id.* at 11, A.4.3.
[86] *Id.* at 14, B.1.
[87] *Id.* at 15, B.2.2.
[88] *Id.* at 16, B.2.4.
[89] *Id.* at 28, D.1.1.
[90] *Id.*
[91] EPA Climate & Social Vulnerability Report.
[92] *Id.* at 35.
[93] *Id.* at 40.

labor-impact areas than non-Indigenous counterparts.[94] In addition, "[c]oastal road networks and the communities they support are increasingly at risk of impacts from sea level rise and intensifying coastal flood events," a risk which again disproportionately impacts communities of color and low-income communities. Communities of color are 41% more likely to live in areas projected to have the highest increase in traffic delays due to climate-driven changes in high-tide flooding with 50 cm of global sea level rise;[95] and Pacific Islanders are 112% more likely to live in areas likely to be excluded from protective adaptation measures that would reduce flooding-related delays.[96]

The takeaway from these most recent reports is clear: the scientific evidence consistently reaffirms that human-caused climate change is already and will continue causing vast and escalating harms—which disproportionately impact communities of color and low-income communities—absent urgent action to reduce GHG emissions.

### C. Climate change threatens human health.

Anthropogenic climate change is already affecting public health, and will pose even more severe threats without action to greatly limit GHGs.[97] EPA has previously recognized that "climate change is expected to increase ozone pollution over broad areas of the U.S., especially on the highest ozone days and in the largest metropolitan areas with the worst ozone problems, and thereby increase the risk of morbidity and mortality."[98] It further summarized findings that "climate change, in addition to chronic stresses such as extreme poverty, is negatively affecting Indigenous peoples' health in the U.S. through impacts such as reduced access to traditional foods, decreased water quality, and increasing exposure to health and safety hazards."[99] The agency also explained that

> children's unique physiology and developing bodies contribute to making them particularly vulnerable to climate change. Impacts on children are expected from heat waves, air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events.[100]

Heat is the most direct health threat from climate change,[101] particularly for older adults and young children, outdoor workers, low-income communities, communities of color, and people with chronic illnesses (*very high confidence*).[102] A 2017 review found evidence for 27 different ways in which extreme heat leads to deadly organ failure, including (but not limited to) such pathologies

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[94] *Id.* at 41.
[95] *Id.* at 48.
[96] *Id.* at 50.
[97] USGCRP, A., J. Balbus, J.L. Gamble, C.B. Beard, J.E. Bell, D. Dodgen, R.J. Eisen, N. Fann, M.D. Hawkins, S.C. Herring, L. Jantarasami, D.M. Mills, S. Saha, M.C. Sarofim, J. Trtanj, and L. Ziska Crimmins, The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment (2016) at 26, https://health2016.globalchange.gov/ [hereinafter USGCRP 2016].
[98] Clean Power Plan, 80 Fed. Reg. at 64,682.
[99] *Id.* at 64,683.
[100] *Id.*
[101] USGCRP 2016 at 30.
[102] *Id.* at 44.

as ischemia (inadequate blood supply), heat cytotoxicity, and inflammatory response—conditions that can affect the brain, heart, intestines, kidneys, and liver.[103] It is very likely that the United States will see thousands to tens of thousands more premature heat-related deaths in the summer under business as usual. The increase in heat deaths will likely be larger than a concomitant decrease in cold-related deaths.[104] Climate-related disasters like inland flooding, wildfires, and hurricanes are also associated with myriad health threats including injuries, skin infections, mental health conditions, and deaths (*high confidence*).[105]

The danger of extreme heat was horrifically clear during the unprecedented heat wave in the Pacific Northwest in June 2021, which resulted in hundreds of deaths.[106] Over a 5 day period, heat records were broken in seven different states,[107] including Oregon which suffered from 117 degree temperatures.[108] The Centers for Disease Control found that, during the height of the Pacific Northwest heat wave from June 25-30, 2021, the number of heat-related emergency room visits was 69 times higher than that during corresponding days in 2019.[109]A recent study concluded that this extreme heat event "was *virtually impossible* without human-caused climate change."[110] While this type of extreme heat event is currently considered a 1 in 1000 year event, if global warming reaches 2°C, the report concludes that this type of extreme event would occur roughly once every 5 to 10 years.[111]

By one estimate, nearly one-third of the world's population is currently exposed to a deadly combination of heat and humidity for at least 20 days a year; without deep cuts in global GHG emissions, that percentage is projected to rise to nearly three-quarters of the world's population by the end of the century.[112] By 2090, 49 U.S. cities will see an estimated 9,300 additional premature

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[103] Mora, C., *et al*., Twenty-Seven Ways a Heat Wave Can Kill You: Deadly Heat in the Era of Climate Change, 10 CIRC. CARDIOVASC. QUAL. OUTCOME e004233 (2017), http://circoutcomes.ahajournals.org/content/10/11/e004233 [hereinafter Mora *et al*. Circ. Cardiovasc. Qual. Outcome].
[104] USGCRP 2016 at 44.
[105] *Id.* at 100.
[106] Eleanor Aspegren, Authorities investigate hundreds of deaths linked to torrid Pacific Northwest weather, USA Today (Jun. 30, 2021) https://www.usatoday.com/story/news/weather/2021/06/30/heat-wave-deaths-pacific-northwest-authorities/7819604002/; Nadja Popovich & Winston Choi-Schagrin, Hidden Toll of the Northwest Heat Wave: Hundreds of Extra Deaths, NY Times (Aug. 11, 2021), https://www.nytimes.com/interactive/2021/08/11/climate/deaths-pacific-northwest-heat-wave.html.
[107] NOAA, Record-breaking June 2021 heatwave impacts the U.S. West (Jun. 23, 2021), https://www.climate.gov/news-features/event-tracker/record-breaking-june-2021-heatwave-impacts-us-west.
[108] Jaclyn Diaz, The West Coast Heat Has Killed Dozens and Hospitalized More in Canada and the U.S., Nat'l Public Radio (Jun. 30, 2021), https://www.npr.org/2021/06/30/1011622492/the-west-coast-heat-has-killed-dozens-and-hospitalized-more-in-canada-and-the-u-
[109] Schramm PJ, Vaidyanathan A, Radhakrishnan L, Gates A, Hartnett K, Breysse P. Heat-Related Emergency Department Visits During the Northwestern Heat Wave — United States, June 2021. MMWR Morb Mortal Wkly Rep 2021;70:1020–1021. DOI: http://dx.doi.org/10.15585/mmwr.mm7029e1.
[110] Philip, S. et al., Rapid attribution analysis of the extraordinary heat wave on the Pacific Coast of the U.S. and Canada June 2021, https://www.worldweatherattribution.org/wp-content/uploads/NW-US-extreme-heat-2021-scientific-report-WWA.pdf.
[111] *Id.*
[112] Mora, C. *et al*., Global Risk of Deadly Heat, 7 NATURE CLIMATE CHANGE 501 (2017), www.nature.com/articles/nclimate3322.

deaths due to heat.[113] Although air conditioning and other response measures can help limit heat-related deaths and illnesses, future increases in heat could "recurrently 'imprison people' indoors and may turn infrastructure failures (e.g., power outages) into catastrophic events."[114] Florida got a taste of that future in 2017 after Hurricane Irma knocked out electricity at a nursing home and at least 14 residents tragically lost their lives due to heat.[115] Extreme heat similarly meant that an Arizona woman's inability to pay her $176 electric bill tragically led to her death in 2019.[116] Similarly, a preliminary study of the June 2021 heat wave showed that all of the people who died in Multnomah County, Oregon, which includes Portland, lacked air conditioning.[117]

Climate change also is likely to worsen air quality by accelerating the formation of ground-level ozone pollution (*high confidence*), increasing fine particle pollution and ozone pollution from wildfires (*high confidence*), and making pollen and mold allergy seasons longer and more severe (*high confidence*).[118] For example, there is consistent evidence that wildfire smoke exacerbates existing respiratory health problems, including increased risk of respiratory infections.[119] One recent study estimated that wildfire smoke from August 1 through September 10, 2020, indirectly led to as many as 3,000 excess deaths in California alone.[120] Similarly, the severe wildfires in summer and fall of 2017 sent people across Washington and California to triage centers, hospitals, and doctors' offices with breathing problems.[121] Communities already suffer a considerable economic burden from the illnesses and deaths related to wildfire smoke. A study that modeled wildfire smoke exposures over the continental U.S. from 2008 to 2012 found that health costs from short-term smoke exposures totaled $63 billion in net present value over the study period, and $450 billion for long-term exposure effects.[122]

In addition to heat-related health risks, the IPCC reports that changes in temperatures and precipitation resulting from climate change will impact the "distribution and range of vector-borne

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[113] US EPA, Multi-Model Framework for Quantitative Sectoral Impacts Analysis: A Technical Report for the Fourth National Climate Assessment, 209-10 (2017), *available at* https://cfpub.epa.gov/si/si_public_record_Report.cfm?dirEntryId=335095 at 48 [hereinafter USEPA 2017].
[114] Mora *et al*., Circ. Cardiovasc. Qual. Outcome.
[115] Nedelman, M., *Husband and Wife Among 14 Dead After Florida Nursing Home Lost A/C*, CNN (Oct. 9, 2017), www.cnn.com/2017/10/09/health/florida-irma-nursing-home-deaths-wife/index.html.
[116] Whitman, E., *On 107-Degree Day, APS Cut Power to Stephanie Pullman's Home. She Didn't Live*, Phoenix New Times (June 13, 2019), https://www.phoenixnewtimes.com/news/aps-cut-power-heat-customer-dead-phoenix-summer-shutoff-11310515.
[117] Nadja Popovich & Winston Choi-Schagrin, Hidden Toll of the Northwest Heat Wave: Hundreds of Extra Deaths, NY Times (Aug. 11, 2021), https://www.nytimes.com/interactive/2021/08/11/climate/deaths-pacific-northwest-heat-wave.html.
[118] USGCRP 2016 at 70.
[119] Reid, C.E., *et al*., Critical Review of Health Impacts of Wildfire Smoke Exposure, 124 ENVIRON. HEALTH PERSPECT. 1334 (2016), http://dx.doi.org/10.1289/ehp.1409277.
[120] A. Buis, NASA, Global Climate Change, The Climate Connections of a Record Fire Year in the U.S. West (Feb. 22, 2021), https://climate.nasa.gov/ask-nasa-climate/3066/the-climate-connections-of-a-record-fire-year-in-the-us-west/ (last accessed Dec. 15, 2021).
[121] Upton, J., Breathing Fire, Climate Central (Nov. 7, 2017), https://californiahealthline.org/news/breathing-fire-health-is-a-casualty-of-climate-fueled-blazes/.
[122] Fann N., *et al*., The Health Impacts and Economic Value of Wildland Fire Episodes in the U.S.: 2008–2012, 610-611 SCI. TOTAL ENVIRON. 802 (2018), www.sciencedirect.com/science/article/pii/S0048969717320223?via%3Dihub.

diseases, such as malaria."[123] The USGCRP has similarly determined with *high confidence* that climate change will alter the geographical extent and seasonal timing of tick- and mosquito-borne diseases like Lyme disease and West Nile Virus.[124] The two species of ticks capable of spreading Lyme disease—the most common vector-borne illness in the U.S.[125]—have already expanded to new regions of the U.S. partly because of rising temperatures,[126] and their range expanded by roughly 45 percent between 1998 and 2015.[127] Globally, climate change has also increased the capacity of mosquitoes to generate new infections of dengue fever, and the number of dengue cases each year has doubled every decade since 1990.[128]

In addition, rising temperatures, more extreme rainfall, and coastal storm surges are expected with *medium confidence* to increase the risk of water-[129] and food-borne illnesses. [130] For example, vibriosis is an infection contracted through contaminated shellfish or seawater that can lead to diarrhea, skin infections, or even death.[131] The bacteria that cause vibriosis grow more quickly in warmer waters and are restricted to warmer months of the year along much of the eastern U.S. coast.[132] Reported cases of vibriosis tripled in the U.S. from 1996 to 2010.[133]

### D. Climate change and ocean acidification harm biodiversity, ecosystem services, and public lands.

In addition to warming Earth's climate generally, it is *virtually certain* that temperatures in the top layer of global oceans have increased since the 1970s, with human influence as the *extremely likely* main driver. [134] Beyond warming the oceans, $CO_2$ emissions have made the surface of global

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[123] Department of Defense, Office of the Undersecretary for Policy, Department of Defense Climate Risk Analysis at 4 (2021), (report submitted to National Security Council), https://media.defense.gov/2021/Oct/21/2002877353/-1/-1/0/DOD-CLIMATE-RISK-ANALYSIS-FINAL.PDF [hereinafter "DoD 2021"] at 9.
[124] USGCRP 2016 at 130.
[125] Schwartz, A.M., *et al*., Surveillance for Lyme Disease — United States, 2008-2015, 66 MMWR 1 (2017), www.cdc.gov/mmwr/volumes/66/ss/ss6622a1.htm.
[126] Eisen, R.J., *et al*., Tick-Borne Zoonoses in the United States: Persistent and Emerging Threats to Human Health, ILAR Journal (2017), https://academic.oup.com/ilarjournal/advance-article/doi/10.1093/ilar/ilx005/3078806.
[127] Eisen, R.J., County-Scale Distribution of *Ixodes scapularis* and *Ixodes pacificus* (Acari: Ixodidae) in the Continental United States, 53 J. MED. ENTOMOL. 349 (2016), https://academic.oup.com/jme/article/53/2/349/2459744.
[128] Watts, N., et al., The *Lancet* Countdown on Health and Climate Change: From 25 Years of Inaction to a Global Transformation for Public Health, Lancet Online First (2017) (Watts et al., 2017), www.thelancet.com/journals/lancet/article/PIIS0140-6736(17)32464-9/fulltext.
[129] USGCRP 2016 at 158.
[130] *Id.* at 190.
[131] Centers for Disease Control and Prevention, *Vibrio vulnificus* & Wounds, https://www.cdc.gov/vibrio/wounds.html?CDC_AA_refVal=https%3A%2F%2Fwww.cdc.gov%2Fdisasters%2Fvibriovulnificus.html (accessed Jan. 27, 2021).
[132] Muhling, B.A., *et al*., Projections of the Future Occurrence, Distribution, and Seasonality of Three Vibrio Species in the Chesapeake Bay Under a High-Emission Climate Change Scenario, 1 GEOHEALTH 278 (2017), doi:10.1002/2017GH000089.
[133] USGCRP 2016 at 164.
[134] IPCC AR6 at 5, A.1.6

oceans about 30 percent more acidic over the last 150 years.[135] There is *medium confidence* that the current rate of acidification is higher than at any time in at least the last 66 million years.[136] Under continued high emissions of $CO_2$, surface acidity is expected with *high confidence* to increase by another 100 to 150 percent by the end of the century.[137] Human-caused CO2 emissions are *virtually certain* to be the main driver of acidification in the open ocean.[138]

Species can respond to climate change in three ways: they can cope through temporary changes or evolutionary adaptation, relocate to new habitats, or go extinct.[139] Both geographic shifts and extinctions will have dramatic consequences for biodiversity and the ecosystem functions on which humans depend.[140]

Because attempting to shift its range is often a species' first response to new environmental pressures, climate change is already "impelling a universal redistribution of life on Earth."[141] In fact, many species have experienced local extinctions at the warm edge of their range as they have shifted to cooler latitudes or elevations. A recent review of 976 plant and animal species around the world found that 47 percent have experienced climate-related local extinctions, with the highest extinction rates occurring in tropical species, animals, and freshwater habitats.[142] The redistribution of species has been linked to reduced terrestrial productivity, alterations in ecological networks in marine habitats, and the development of toxic algal blooms.[143]

Many species will be unable to move quickly enough—or at all—due to geographical barriers such as oceans or mountains, characteristics of their life history, a lack of suitable new habitat, or the rapid pace of local changes in climate.[144] For instance, high temperatures, ocean acidification, and non-climate stressors are already causing significant losses of shallow coral reefs in the U.S.[145] By one estimate, 4.3ºC of additional global warming caused by continued high levels of GHGs could lead to the extinction of 1 in 6 of the world's species.[146]

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[135] USGCRP 2017 at 372. Acidification is causing many parts of the ocean to be undersaturated with the calcium carbonate minerals that are the building blocks for the skeletons and shells of many marine organisms, which impairs these organisms' ability to produce and maintain their skeletons and shells. *See* Pacific Marine Environmental Laboratory, National Oceanic and Atmospheric Administration, What Is Ocean Acidification (accessed Jan. 27, 2021), https://www.pmel.noaa.gov/co2/story/What+is+Ocean+Acidification%3F.
[136] USGCRP 2017 at 364.
[137] *Id.*
[138] IPCC AR6 at 5, A.1.6
[139] Wiens, J.J., Climate-Related Local Extinctions are Already Widespread Among Plant and Animal Species, 14 PLOS Biology e2001104 (2016), http://journals.plos.org/plosbiology/article?id=10.1371/journal.pbio.2001104 [hereinafter Wiens 2016].
[140] Pecl, G.T., *et al*., Biodiversity Redistribution Under Climate Change: Impacts on Ecosystems and Human Well-Being, 355 SCIENCE eaai9214 (2017) [hereinafter Pecl *et al*. 2017]; *see also* Wiens 2016.
[141] Pecl *et al*. 2017.
[142] Wiens 2016.
[143] Pecl *et al*. 2017.
[144] Wiens 2016; Vázquez, D.P., *et al*., Ecological and Evolutionary Impacts of Changing Climatic Variability, 92 BIOL. REV. 22 (2017; first published Aug 2015), http://onlinelibrary.wiley.com/doi/10.1111/brv.12216/abstract.
[145] USEPA 2017 at 171.
[146] Urban, M.C., Accelerating Extinction Risk from Climate Change, 348 SCIENCE 571 (2015), http://science.sciencemag.org/content/sci/348/6234/571.full.pdf.

America's national parks are bellwethers for many of these changes. A recent spatial analysis, which examined past and future impacts at 417 national parks, concluded that "climate change exposes the national park area more than the US as a whole."[147] Because national parks are often located in already more extreme environments, they are more vulnerable to climate change. For example, the study concluded that the average annual temperature in national parks increased at twice the rate of the rest of the country between 1895 and 2010.[148] Looking forward to 2100, "under the highest emissions scenario . . . , park temperatures would increase 3°C–9°C, with climate velocities outpacing dispersal capabilities of many plant and animal species." [149] While reducing emissions would not eliminate this trend, "greenhouse gas emissions reductions could reduce projected temperature increases in national parks by one-half to two-thirds."[150] Our national parks are living emblems of our nation's heritage, and they warrant regulations and policies that promote ecosystem resilience, enhance restoration and conservation of the system's essential resources, and preserve America's natural and cultural legacy.

### E. Climate change hurts the U.S. economy.

Climate- and weather-related disasters are already harming the U.S. economy. Since 1980, there have been 308 weather and climate disasters that cost the country at least $1 billion each, for a total cost of more than $2 trillion.[151] And data indicates that the economic damage from extreme weather events has been increasing in recent years.[152] In the last five years, there have been 81 such events, resulting in nearly 4,000 deaths and over $640 billion in damages.[153] In 2017 alone, there were 16 separate weather and climate disaster events in the U.S. with damages exceeding $1 billion each, totaling $306 billion—a new single-year record.[154] In 2020, there were 22 weather and climate disaster events with losses exceeding $1 billion each.[155] Overall, with annual losses exceeding $95 billion, 2020 ranked as the fourth highest annual loss year on record.[156]

According to a 2017 technical assessment by EPA's Climate Change Impacts and Risk Analysis ("CIRA") project, climate change will cost the U.S. economy hundreds of billions of dollars each year under conservative estimates.[157] Projected damages are significantly larger under a high-emissions scenario. Damages also increase over time, but not necessarily gradually; abrupt

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[147] Gonzalez P, et al., Disproportionate magnitude of climate change in United States national parks, 13 Environmental Research Letters 104001 (Oct. 2018), https://iopscience.iop.org/article/10.1088/1748-9326/aade09.
[148] *Id.*
[149] *Id.*
[150] *Id.*
[151] NOAA National Centers for Environmental Information (NCEI), U.S. Billion-Dollar Weather and Climate Disasters (accessed Dec. 14, 2021), https://www.ncdc.noaa.gov/billions/.
[152] NOAA, 2020 Annual National Climate Report, "Billion-Dollar Weather and Climate Disasters", https://www.ncdc.noaa.gov/sotc/national/202013.
[153] NOAA National Centers for Environmental Information (NCEI), U.S. Billion-Dollar Weather and Climate Disasters (2021), https://www.ncdc.noaa.gov/billions/.
[154] *Id.*
[155] NOAA, 2020 Annual National Climate Report, "Billion-Dollar Weather and Climate Disasters", https://www.ncdc.noaa.gov/sotc/national/201713
[156] *Id.*
[157] USEPA 2017.

changes in climate may likewise lead to abrupt increases in economic harm.[158] Some of the major climate-related economic impacts examined include: labor losses ($160 billion per year), heat-related deaths ($140 billion per year),[159] damage to coastal property ($120 billion per year), damage to roads ($20 billion per year), need for increased electricity generation ($9.2 billion per year),[160] and disruption of international supply chains.[161]

Changes in extreme temperature, particularly heat, are expected to reduce the number of suitable working hours in the contiguous U.S. by 1.9 billion hours in 2090.[162] Globally, heat has already reduced outdoor labor capacity in rural areas by approximately 5.3 percent from 2000 to 2016.[163] In 2013, 16,320 U.S. workers missed work because of heat-related illnesses.[164] By the end of the century, warming on our current high emissions trajectory could cost the U.S. economy hundreds of billions of dollars each year and up to 10 percent of U.S. gross domestic product due to damages including lost crop yields, lost labor, increased disease incidence, property loss from sea level rise, and extreme weather damage.[165] To put that worst case estimate into context, 10 percent of the U.S.' gross domestic product for 2020 amounts to nearly 2.1 trillion dollars.[166]

### F. Climate change threatens national security.

Military and intelligence leaders have long recognized the national security threats of climate change.[167] Most recently, in a 2021 report to the National Security Council, the Department of Defense concluded:

> To keep the nation secure, we must tackle the existential threat of climate change. The unprecedented scale of wildfires, floods, droughts, typhoons, and other extreme weather events of recent months and years have damaged our installations and bases, constrained force readiness and operations, and contributed to instability around the world.[168]

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[158] *Id.* at 3, 4.
[159] *Id.* at 48.
[160] *Id.* at 120.
[161] DoD 2021 at 9 ("Global supply chains are at risk to extreme weather events exacerbated by climate change. For example, the 2011 floods in Thailand disrupted production of components for global companies including computer disk drives and cars.").
[162] *Id.* at 54.
[163] Watts et al., 2017 at 581.
[164] Office of Congressional Workplace Rights, Fast Facts — Heat Stress: Don't Let the Heat Get You Down, https://www.ocwr.gov/publications/fast-facts/heat-stress/ (accessed Jan. 27, 2022).
[165] Jay, et al. In 2018: Reducing Risks Through Emissions Mitigation. In Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II, at 1357 to 1361.
[166] Countryeconomy.com, United States (USA) GDP – Gross Domestic Product (accessed Dec. 14, 2021), https://countryeconomy.com/gdp/usa?year=2020.
[167] The Climate and Security Advisory Group, A Responsibility to Prepare (2018), https://climateandsecurity.files.wordpress.com/2018/02/climate-and-security-advisory-group_a-responsibility-to-prepare_2018_02.pdf.
[168] DoD 2021 at 4, 8 ("As the frequency and intensity of these hazards increase, impacts are likely to expand competition over regions and resources, affect the demands on and functionality of military operations, and increase the number and severity of humanitarian crises, at times threatening stability and security.").

The Department of Defense "sees climate change as a present security threat, not strictly a long-term risk," and is "already observing the impacts of climate change in shocks and stressors to vulnerable nations and communities, including in the United States, and in the Arctic, Middle East, Africa, Asia, and South America."[169]

The threats posed to national security will only increase as climate change gets worse. In its 2021 report, the Department explained that, "in worst-case scenarios, climate change-related impacts could stress economic and social conditions that contribute to mass migration events or political crises, civil unrest, shifts in the regional balance of power, or even state failure."[170] In fact, the Department warned that, "[a]s the likelihood of multiple converging extreme events increases with climate change, risks can compound and put enormous pressure on any government's capacity to respond, increasing the possibility of cascading security impacts."[171] Extreme heat, storms and floods, sea level rise, and loss of natural resources will damage military installations, disrupt supply chains, imperil the safety of personnel, hamper training and readiness, increase the need for deployments in high risk areas of the world, and dramatically increase operating costs—exposing America's service personnel and citizens at home and abroad to needless risks and preventable harms.[172]

### G. Methane is an extremely potent greenhouse gas that exacerbates climate change.

Methane is far more potent as a greenhouse gas than CO2, especially over shorter time periods. AR6 reports that, over a twenty-year timeframe, methane has approximately 83 times the global warming potential (GWO") of CO2, and approximately 30 times the CO2 value over a 100-year time frame.[173] Given the urgency of near-term GHG reductions, particularly dramatic cuts in the next two decades, the twenty-year GWP is the more appropriate metric to use when evaluating the climate impacts of government policies (such as the current rule proposal) that will affect methane emissions.

In a 2021 report, the United Nations Environment Programme and the Climate and Clean Air Coalition concluded that "[r]educing human-caused methane emissions is one of the most cost-effective strategies to rapidly reduce the rate of warming and contribute significantly to global

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[169] *Id.* at 14.
[170] *Id.* at 8.
[171] *Id.* 2021 at 9.
[172] National Intelligence Council, Implications for US National Security of Anticipated Climate Change (2016), https://www.dni.gov/index.php/newsroom/reports-publications/reports-publications-2016/item/1629-implications-for-us-national-security-of-anticipated-climate-change; Office of the Under Secretary of Defense for Acquisition, Technology, and Logistics, Climate-Related Risk to DoD Infrastructure Initial Vulnerability Assessment Survey (SLVAS) Report (2018), https://reliefweb.int/report/world/department-defense-climate-related-risk-dod-infrastructure-initial-vulnerability; Gregg Garfin, Climate Change Impacts and Adaptation on Southwestern DoD Facilities (2017), https://www.serdp-estcp.org/Program-Areas/Resource-Conservation-and-Resiliency/Infrastruct 7607ure-Resiliency/Vulnerability-and-Impact-Assessment/RC-2232; USDOD 2021 at 9.
[173] IPCC AR6, WG 1, The Physical Science Basis at 7-125.

efforts to limit temperature rise to 1.5°C." [174] That report found that targeted cuts in methane emissions of ~45% (180 metric tons a year) by 2030 are considered necessary to meet the 1.5°C climate limit and would "avoid nearly 0.3°C of global warming by the 2040s." [175] Such cuts would also, each year, "prevent 255,000 premature deaths, 775,000 asthma-related hospital visits, 73 billion hours of lost labour from extreme heat, and 26 million tonnes of crop losses globally." [176] Because methane has a relatively short lifetime, urgent steps to reduce methane emissions "can quickly reduce atmospheric concentrations and result in similarly rapid reduction in climate forcing and ozone pollution."[177] Reducing methane emissions also reduces the risk of dangerous climate-warming feedback loops.[178] In total, the report estimates that "global monetized benefits for all market and non-market impacts are approximately $4300 per tonne of methane reduced." [179]

Along with $CO_2$, methane is considered one of the "well-mixed" GHGs that *unequivocally* "are the main driver of increases in atmospheric GHG concentrations since the pre-industrial period."[180] It is also *unequivocal* that the increased concentration of methane, as well as other well-mixed GHGs, "over the industrial era is the result of human activities (*very high confidence*)." [181] Comparisons between $CO_2$ and methane depend on methane's "shorter atmospheric lifetime, stronger warming potential, and variations in atmospheric growth rate over the past decade."[182] Methane also contributes to the creation of ground-level ozone, which is itself a powerful greenhouse gas that also causes direct health harms.[183] For this reason, "[c]ontrolling methane has been shown to be a win-win, benefiting both climate and air quality."[184]

Over the past two centuries, methane emissions have nearly doubled, humans have been the primary cause of the growth since 1900, and emissions increases have "persistently exceeded the losses," leading to accumulation of methane in the atmosphere.[185] According to AR6, the average global concentration of methane increased over 150% between 1750 and 2019 (high confidence),

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[174] Climate and Clean Air Coalition & United Nations Environment Programme, Global Methane Assessment: Summary for Decision Makers at 1 (2021), https://www.ccacoalition.org/en/resources/global-methane-assessment-summary-decision-makers [hereinafter "Global Methane Assessment 2021"].
[175] *Id.*; *see also* Sun et al., *Path to net zero is critical to climate outcome*, 11 Sci. Reports 22173 (2021), https://www.nature.com/articles/s41598-021-01639-y ("[D]ifferent pathways of carbon dioxide and methane . . . can lead to nearly 0.4 °C of warming difference in midcentury and potential overshoot of the 2°C target, even if they technically reach global net zero greenhouse gas emissions in 2050.")
[176] Global Methane Assessment 2021 at 1.
[177] *Id.* at 8.
[178] *Id.*
[179] *Id.*
[180] IPCC AR6, WG 1, The Physical Science Basis at 5-6.
[181] *Id.*
[182] Saunios, M. et al., The Global Methane Budget 2000–2017, 12 Earth Syst. Sci. Data 1561–1623 (2020), https://doi.org/10.5194/essd-12-1561-2020.
[183] Global Methane Assessment 2021.
[184] He, J., Naik, V., Horowitz, L. W., Dlugokencky, E., and Thoning, K., Investigation of the global methane budget over 1980–2017 using GFDL-AM4.1, 20 Atmos. Chem. Phys. 805–827 (2020), https://doi.org/10.5194/acp-20-805-2020.
[185] IPCC AR6, WG 1, The Physical Science Basis at 5-34.

[186] and "[c]urrent atmospheric concentrations of [methane and other well-mixed] GHGs are higher than at any point in the last 800,000 years."[187] Most recently, from 2010-2019, the atmospheric methane concentration grew on average 7.6 ppb per year, although the growth rate was faster (9.3 ppb/yr) from 2014-2019 (high confidence). Methane concentration increased by nearly 15 ppb in 2020, "which is by far the largest annual increase since systematic atmospheric CH4 measurements began."[188] The IPCC recently concluded with *high confidence* that the growth in methane since the early 2000s "is dominated by anthropogenic activities," primarily "emissions from both fossil fuels and agriculture (dominated by livestock) sectors (*medium confidence*)." [189] The Global Methane Assessment concluded that fossil fuels were responsible for 35% of human-caused methane emissions globally. [190]

### H. Methane emissions from the oil and gas sector are significant and can be easily mitigated to slow the rate of global warming.

Over the past decade, a substantial body of scientific literature has developed documenting the significance of methane emissions caused by oil and gas production.[191] Numerous studies have found that official inventory estimates of oil and gas methane emissions are inaccurate – far lower than what is typically actually observed in the field.[192] Official inventory estimates are generated using "bottom up" methods, which rely on component or equipment level emission factors and scaling using activity data to form a picture of overall emissions.[193] Using "top down" methods that employ field observations of actual emissions, scientists have found emissions roughly 1.5-2 times higher than official estimates.[194] This large discrepancy is attributed to the failure of bottom up methods to account for large, intermittent emission events that can represent 50% or more of

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[186] *Id.* at 5-6; State of the Climate 2020, (Aug. 2021), https://ametsoc.net/sotc2020/State_of_the_Climate_in_2020_LowRes96.pdf ("[Methane's] abundance in the atmosphere increased to 1879.2 ± 1.0 ppb (parts per billion by moles in dry air) in 2020, a 160% increase compared to its pre-industrial level of 722 ± 15 ppb.").

[187] IPCC AR6, WG 1, The Physical Science Basis at 5-6.

[188] State of the Climate 2020, (Aug. 2021), https://ametsoc.net/sotc2020/State_of_the_Climate_in_2020_LowRes96.pdf.

[189] IPCC AR6, WG 1, The Physical Science Basis at 5-7.

[190] Global Methane Assessment 2021.

[191] *E.g.*, Ramón A. Alvarez et al., *Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain*, 361 SCIENCE 186, 186 (2018); Benjamin Hmiel et al., *Preindustrial 14CH4 Indicates Greater Anthropogenic Fossil CH4 Emissions*, 578 NATURE 409, 409 (2020); Stefan Schwietzke et al., *Upward Revision of Global Fossil Fuel Methane Emissions Based on Isotope Database*, 538 NATURE 88 (2016); Howarth, R. W. *A bridge to nowhere: methane emissions and the greenhouse gas footprint of natural gas*, 2 Energy Sci. Eng. 47–60 (2014).

[192] *See, e.g.*, Zavala-Araiza et al., Reconciling divergent estimates of oil and gas methane emissions, 51 Proc. Natl. Acad. Sci. 15597 (2015), https://www.pnas.org/content/112/51/15597; Vaughn, et al., Temporal variability largely explains top-down/bottom-up difference in methane emission estimates from a natural gas production region. 46 Proc. Natl. Acad. Sci. 11712 (2018), https://doi.org/10.1073/pnas.1805687115.

[193] EPA, Inventory of Greenhouse Gas Emissions and Sinks (2019), https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks.

[194] Rutherford et al., *Closing the methane gap in US oil and natural gas production emissions inventories*, 12 Nature Comms. 4715 (2021), https://www.nature.com/articles/s41467-021-25017-4.

the sector's total emissions.[195] These large emission events, referred to as "super-emitters," typically result from abnormal operating conditions and equipment failures.[196]

Methane emissions from the oil and gas sector are a significant driver of near-term climate change, and reducing them is one of the easiest and most cost-effective ways to immediately slow the rate of global warming.[197] Under the International Energy Agency's (IEA) "net-zero by 2050" scenario, methane from fossil fuel operations needs to decline by around 75% between 2020 and 2030.[198] The IEA also found that almost 45% of oil and gas methane emissions could be avoided at no net cost.[199] Because of methane's extreme climate-forcing power and its relatively short atmospheric lifespan, immediate reductions are critical. A recent report found that "[p]ursuing all [methane] mitigation measures now could slow the global-mean rate of near-term decadal warming by around 30%, avoid[ing] a quarter of a degree centigrade of additional global-mean warming by midcentury, and set[ting] ourselves on a path to avoid more than half a degree centigrade by end of century."[200] The report examines abatement potentials across methane-emitting sectors, categorizing mitigation policies with no net cost as "economically feasible" and other mitigation policies as "technically feasible."[201] As shown in Figure 1 below, the oil and gas sector has the greatest abatement potential, with nearly all measures coming at no net cost.

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[195] *Id.*

[196] Zavala-Araiza et al., *Toward a Function Definition of Methane Super-Emitters: Application to Natural Gas Production Sites*, 49 Env. Sci. Tech. 8167 (2015), https://pubs.acs.org/doi/pdf/10.1021/acs.est.5b00133; Zavala-Araiza et al., *Super-emitters in natural gas infrastructure are caused by abnormal process conditions*, 8 Nature Comms. 14012 (2017) https://doi.org/10.1038/ncomms14012.

[197] Ocko et al., Acting rapidly to deploy readily available methane mitigation measures by sector can immediately slow global warming, 16 Env. Research Letters 054042 (2021), https://iopscience.iop.org/article/10.1088/1748-9326/abf9c8; IEA, Methane Emissions from Oil and Gas (2021), [hereinafter "IEA 2021"] https://www.iea.org/reports/methane-emissions-from-oil-and-gas ("Fossil fuel operations generated nearly one-third of all methane emissions from human activity. Action on methane is therefore one of the most effective steps the energy sector can take to mitigate climate change.").

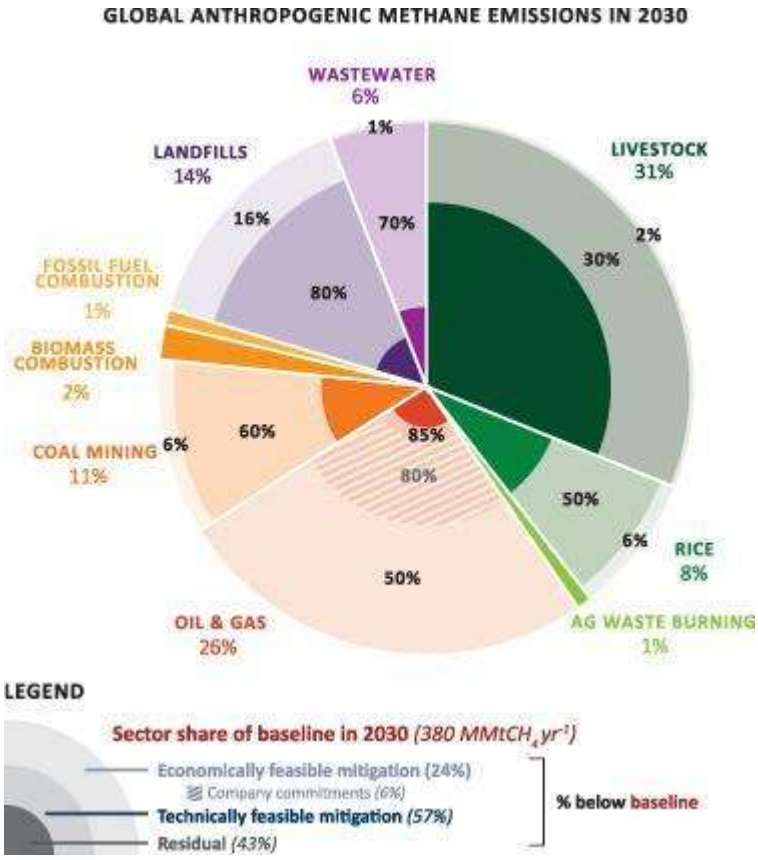
[198] IEA 2021 ("Methane emissions from oil and gas operations must be the first to go.").

[199] *Id.*

[200] Ocko et al., Acting rapidly to deploy readily available methane mitigation measures by sector can immediately slow global warming, 16 Env. Research Letters 054042 (2021), https://iopscience.iop.org/article/10.1088/1748-9326/abf9c8;

[201] *Id.*

**Figure 1: Global Methane Abatement Potential by Sector**[202]




The UNEP has similarly highlighted the critical importance of reducing methane from fossil fuel operations, finding that these emissions must decline 59% from 2020 levels by 2030 in scenarios where the 1.5°C goal is attained.[203] The UNEP also finds that up to 80% of oil and gas sector mitigation measures could be implemented at low (less than $600/ton) or no cost, and in North America, up to 92% of oil and gas sector emissions could be reduced at a negative cost.[204] Reducing oil and gas methane emissions is one of the most attainable and cost-effective climate mitigation strategies, and it must be done as quickly as possible to limit global temperature rise to 1.5°C.

EPA's OOOOb and c rulemaking therefore is of critical importance: without sharp and immediate reductions in oil and gas sector methane, the United States will be unable to meet its GHG reduction targets that are necessary for avoiding the most devastating impacts of climate change that are anticipated for Earth's near- and long-term future.

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[202] *Id.*

[203] United Nations Environment Programme and Climate and Clean Air Coalition, Global Methane Assessment: Benefits and Costs of Mitigating Methane Emissions 89 (2021).

[204] UNEP SPM at 10; United Nations Environment Programme and Climate and Clean Air Coalition, Global Methane Assessment: Benefits and Costs of Mitigating Methane Emissions 101 (2021).

## I. Oil and Gas Operations Cause Adverse Health Impacts

### 1. *Ozone-forming Volatile Organic Compounds (VOCs) and Hazardous Air Pollutants (HAPs) like Benzene Harm Human Health*

***VOCs and Ozone***. In addition to methane, oil and gas operations emit volatile organic compounds which contribute to the formation of ground-level ozone (a primary component of smog).

A longstanding body of scientific research, including numerous EPA assessments, demonstrates that exposure to ground-level ozone harms human health. In its 2013 Integrated Scientific Assessment for Ozone, EPA concluded that "a very large amount of evidence spanning several decades supports a relationship between exposure to [ozone] and a broad range of respiratory effects."[205] These effects range from decreases in lung function among healthy adults to increases in respiratory-related hospital admissions and emergency room visits, to premature death.[206] For example, there is a strong link between ozone and asthma. Multiple studies across various states (California, Georgia, North Carolina), counties (Maricopa County, AZ; Erie County, NY) and cities (Seattle, New York, Newark, Atlanta, Houston, Dallas, San Antonio, Austin, Indianapolis, St Louis) have found that changes in ozone concentrations were associated with higher asthma emergency room visits, most at concentrations below the current standard.[207] According to the Centers for Disease Control and Prevention, asthma affects 25 million Americans and results in 1.7 million emergency room visits, 9.7 million visits to the physician and 188 thousand hospitalizations.[208] Asthma costs the U.S. economy more than $80 billion annually in medical expenses, missed work and school days, and deaths.[209] It is estimated that up to 11% of all asthma emergency room visits in the United States are attributed to ozone.[210]

Long-term exposure to ozone can have particularly severe health implications. EPA has concluded that there is "likely to be a causal relationship between long-term exposure to [ozone] and respiratory effects."[211] Similarly, EPA notes that "recent evidence is suggestive of a causal relationship between long-term [ozone] exposures and total mortality."[212] Some longitudinal studies have further demonstrated that "long-term [ozone] exposure influences the risk of asthma

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[205] *2013 Final Report: Integrated Science Assessment of Ozone and Related Photochemical Oxidants* ("ISA") (EPA/600/R-10/076F) at 1-6.
[206] *Id.* at 6-131 to 6-158, 6-162 to -163.
[207] Stephanie Holm, John Balmes, Ananya Roy, *Human Health Effects of Ozone: The State of Evidence Since EPA's Last Integrated Science Assessment*, EDF 2018.
[208] *Available at* https://www.cdc.gov/asthma/most_recent_national_asthma_data.htm, last accessed on Jan. 27, 2022.
[209] Tursynbek Nurmagambetov, Robin Kuwahara, Paul Garbe, *The Economic Burden of Asthma in the United States, 2008 – 2013,* Annals of the American Thoracic Society, 2018).
[210] Susan C. Anenberg, Daven K. Henze, Veronica Tinney, Patrick L. Kinney, William Raich, Neal Fann, Chris S. Malley, Henry Roman, Lok Lamsal, Bryan Duncan, Randall V. Martin, Aaron van Donkelaar, Michael Brauer, Ruth Doherty, Jan Eiof Jonson, Yanko Davila, Kengo Sudo, Johan C.I. Kuylenstierna, *Estimates of the Global Burden of Ambient PM2.5, Ozone, and NO2 on Asthma Incidence and Emergency Room Visits*, Environmental Health Perspectives, 2018; 126 (10): 107004.
[211] ISA at 1-8.
[212] *Id.*

development in children"[213] and a recent study of 5,780 adults followed for a decade across 6 US metropolitan regions found that long-term ozone was significantly associated with development of emphysema. This was equal to that of 29 pack-years of smoking or 3 years of aging.[214] Additionally, in a study of 11 million Medicare enrollees in the Southeastern U.S., long-term ozone was associated with increased risk of first hospital admissions for stroke, chronic obstructive pulmonary disease, pneumonia, myocardial infarction, lung cancer, and heart failure.[215]

However, even short-term exposure to ozone can be quite damaging to cardiovascular and respiratory systems. For instance, there is evidence of an association between out-of-hospital cardiac arrests and short-term exposure to ozone, as reported in Ensor, et al., 2013.[216] Other studies indicate higher rates of stroke in populations following higher exposures to ozone. A study in Pennsylvania that used a time-stratified case-crossover analysis to evaluate the relationships between stroke hospital admissions and ozone among 26,219 patients in Allegheny County, PA, found that exposures to ozone on the current day increased the risk of total stroke hospitalization.[217] Another study in Nunces County, Texas evaluated associations with incident stroke and stroke severity in cases identified in the Brain Attack Surveillance in Corpus Christi project between 2000 and 2012 and found elevated risk of having a first stroke with higher ozone concentrations in the preceding 2 days.[218] This is supported by two independent meta- analyses of multiple studies.[219] This evidence augments the long-standing body of literature demonstrating the serious impacts from short-term exposure to ozone pollution, including the increased risk of premature death.[220] EPA has also recognized that positive associations have been reported between "short-term [ozone] exposures and respiratory mortality, particularly during the summer months."[221]

Health effects other than those impacting cardiovascular or respiratory systems are also likely. A 2017 study suggested that ozone exposure may be linked to approximately 8,000 stillbirths per year.[222] Studies carried out in California and Florida, of over 400,000 births each, found that

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[213] ISA at 7-2.
[214] Wang, Meng, et al. *Association between long-term exposure to ambient air pollution and change in quantitatively assessed emphysema and lung function*. JAMA 322.6 (2019): 546-556.
[215] Yazdi, Mahdieh Danesh, et al. "Long-term exposure to PM2. 5 and ozone and hospital admissions of Medicare participants in the Southeast USA." Environment international 130 (2019): 104879.
[216] Katherine B. Ensor, *et al*., *A Case-Crossover Analysis of Out-of-Hospital Cardiac Arrest and Air Pollution*, 127 CIRCULATION 1192 (2013), https://www.ncbi.nlm.nih.gov/pubmed/23406673.
[217] Xu X, Sun Y, Ha S, Talbott EO, Lissaker CT, *Association between ozone exposure and onset of stroke in Allegheny County, Pennsylvania, USA, 1994-2000,* Neuroepidemiology, 2013; 41(1):2-6.
[218] Wing JJ, Adar SD, Sánchez BN, Morgenstern LB, Smith MA, Lisabeth LD, *Short-term exposures to ambient air pollution and risk of recurrent ischemic stroke*, Environmental Research, Jan. 2017; 152:304-7.
[219] Shah, Anoop SV, et al., *Short term exposure to air pollution and stroke: systematic review and meta-analysis*, BMJ 350 (2015): h1295; Yang, Wan-Shui, et al., *An evidence-based appraisal of global association between air pollution and risk of stroke*, International Journal of Cardiology 175.2 (2014): 307-313.
[220] *ISA* at 1-14 (concluding that there is "likely to be a causal relationship between short-term exposures to [ozone] and total mortality").
[221] EPA, *National Ambient Air Quality Standards for Ozone*, 80 Fed. Reg. 65,292, 65,307 (Oct. 26, 2015); *see also ISA* 6-220 to 6-221.
[222] Mendola et al., *Chronic and Acute Ozone Exposure in the Week Prior to Delivery is Associated with the Risk of Stillbirth*, 14 INT'L J. ENVT'L RESEARCH AND PUB. HEALTH 731 (2017).

elevated exposure to ozone during pregnancy was associated with higher risk of preterm birth.[223] There is also now accumulating evidence that suggests that ozone exposure during pregnancy can result in Autism Spectrum Disorder among children.[224] Prolonged exposure to ozone may also accelerate cognitive decline in the early stages of dementia.[225]

Ozone pollution is particularly harmful for vulnerable populations, such as people with respiratory diseases or asthma, older adults, and people who are active outdoors, especially outdoor workers.[226] Children with asthma face heightened risks from ozone exposure. Many studies have demonstrated that children with asthma experience decrements in lung function and increases in respiratory symptoms when exposed to ozone pollution.[227]

***Hazardous Air Pollutants***. Hazardous Air Pollutants ("HAPs"), which are also released alongside methane during the course of oil and gas operations, can cause cancer and seriously impair human neurological systems.

For example, EPA has found that benzene, found naturally in oil and gas, is a "known human carcinogen (causing leukemia) by all routes of exposure, and… that exposure is associated with additional health effects, including genetic changes in both humans and animals."[228] Further, several adverse noncancer health effects have been associated with chronic inhalation of benzene in humans including arrested development of blood cells, anemia, leukopenia, thrombocytopenia, and aplastic anemia.[229]

Along with benzene, EPA has also cataloged the harmful effects of other specific air toxics emitted from oil and gas operations, including toluene, carbonyl sulfide, ethylbenzene, mixed xylenes, n-hexane, and other air toxics.[230] Each of these hazardous pollutants is harmful to human health. For instance, the serious health effects associated with exposure to toluene range from dysfunction of the central nervous system to narcosis, with effects "frequently observed in humans acutely exposed to low or moderate levels of toluene by inhalation."[231]
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[223] Laurent O, Hu J, Li L, et al. *A statewide nested case-control study of preterm birth and air pollution by source and composition: California, 2001-2008.* Environ Health Perspect. 2016;124(9):1479-1486; Ha S, Hu H, Roussos-Ross D, Haidong K, Roth J, Xu X. *The effects of air pollution on adverse birth outcomes.* Environ Res. 2014;134:198-204.
[224] Becerra, Tracy Ann, et al, *Ambient air pollution and autism in Los Angeles county, California*, Environmental Health Perspectives 121.3 (2012) 380-386; Volk HE, Lurmann F, Penfold B, Hertz-Picciotto I, McConnell R, *Traffic-related air pollution, particulate matter, and autism*, JAMA Psychiatry (Jan. 1, 2013); 70(1):71-7.
[225] Galkina Cleary et al., *Association of Low-Level Ozone with Cognitive Decline in Older Adults*, 61 J. ALZHEIMERS DISEASE 1, 67-78 (2018).
[226] *ISA* at 1-8.
[227] K. Mortimer et al., *The Effect of Air Pollution on Inner-City Children with Asthma*, 19 EUR. RESPIRATORY J. 699 (2002), *ISA*, 6-120–21, 6-160.
[228] RIA at 3-22.
[229] *Id.* at 3-23.
[230] RIA at 3-23-326.
[231] RIA at 3-24.

### 2. *The Oil and Gas Sector is a Substantial Source of Ozone and HAP Emissions*

***VOCs, NOx, and Ozone.*** The oil and natural gas sector is a substantial source of ozone-forming emissions like NOx and VOCs. According to EPA's most recent National Emissions Inventory (NEI), "Oil and Gas Production" is the largest source of human-caused VOCs nationally and a major contributor to NOx emissions.[233] Regional analyses likewise underscore the significant VOC emissions from these sources, including work in the Uinta Basin in Utah,[234] the Barnett Shale in Texas,[235] and in Colorado.[236] For example, a recent study by NOAA scientists at the Cooperative Institute for Research in Environmental Sciences ("CIRES") found that, on Colorado's Northern Front Range, oil and gas operations contribute roughly 50% to regional VOC reactivity and that these activities are responsible for approximately 20% of all regional ozone production.[237] Another study analyzing ozone impacts associated with unconventional natural gas development in Pennsylvania concluded that "natural gas emissions may affect compliance with federal ozone standards,"[238] and an analysis in the Haynesville Shale in Texas found that emissions associated with projected future production from the oil and gas sector could be responsible for as much as a

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[233] Calculation based on EPA, National Emissions Inventory (NEI) Sector Data, *available at* https://www.epa.gov/air-emissions-inventories/2017-national-emissions-inventory-nei-data.

[234] Warneke, C. et al., "Volatile organic compound emissions from the oil and natural gas industry in the Uintah Basin, Utah: oil and gas well pad emissions compared to ambient air composition," 14 Atmos. Chem. Phys., 10977–10988 (2014), *available at* www.atmos-chem- phys.net/14/10977/2014/; DEQ, ENVIRON, "Final Report: 2013 Uinta Basin Winter Ozone Study," (Mar. 2014), *available at* https://deq.utah.gov/locations/U/uintahbasin/ozone/docs/2014/06Jun/UBOS2013FinalReport/Title_Contents_UBOS_2013.pdf

[235] David T. Allen, "Atmospheric Emissions and Air Quality Impacts from Natural Gas Production and Use," Annu. Rev. Chem. Biomol. Eng. 5:55–75 (2014), *available at* http://www.annualreviews.org/doi/abs/10.1146/annurev-chembioeng-060713-035938.

[236] Helmig, D., "Air quality impacts from oil and natural gas development in Colorado," 8,4 Elem Sci. Anth. (2020), *available at* https://doi.org/10.1525/elementa.398; Brantley, et al., "Assessment of volatile organic compound and hazardous air pollutant emissions from oil and natural gas well pads using mobile remote and onsite direct measurements," Journal of the Air & Waste Management Association 1096-2247 (Print) 2162- 2906 (Online) (2015); Pétron, G., et al., "A new look at methane and non-methane hydrocarbon emissions from oil and natural gas operations in the Colorado Denver-Julesburg Basin," 119 J. Geophys. Res. Atmos., 6836–6852 (2014), *available at* http://onlinelibrary.wiley.com/doi/10.1002/2013JD021272/full.

[237] McDuffie, E. E., et al. (2016), Influence of oil and gas emissions on summertime ozone in the Colorado Northern Front Range, J. Geophys. Res. Atmos., 121, 8712–8729, doi:10.1002/2016JD025265. http://onlinelibrary.wiley.com/doi/10.1002/2016JD025265/abstract. *See also* Gilman, J. B., B. M. Lerner, W. C. Kuster, and J. A. de Gouw (2013), *Source signature of volatile organic compounds from oil and natural gas operations in northeastern Colorado*, Environ. Sci. Technol., 47(3), 1297–1305, *available at* http://pubs.acs.org/doi/abs/10.1021/es304119a (finding 55% of VOC reactivity in the metro- Denver area is due to nearby O&NG operations and calling these emissions a "significant source of ozone precursors."); Cheadle, LC et al., *Surface ozone in the Colorado northern Front Range and the influence of oil and gas development during FRAPPE/DISCOVER-AQ in summer 2014*, Elementa (2017), *available at* http://doi.org/10.1525/elementa.254 (finding on "individual days, oil and gas O3 precursors can contribute in excess of 30 ppb to O3 growth and can lead to exceedances" of the EPA ozone standards).

[238] Swarthout, R. F., R. S. Russo, Y. Zhou, B. M. Miller, B. Mitchell, E. Horsman, E. Lipsky, D. C. McCabe, E. Baum, and B. C. Sive (2015), *Impact of Marcellus Shale natural gas development in southwest Pennsylvania on volatile organic compound emissions and regional air quality*, Environ. Sci. Technol., 49(5), 3175–3184, doi:10.1021/es504315f, *available at* https://www.ncbi.nlm.nih.gov/pubmed/25594231.

5 ppb increase in 8-hour ozone design levels.[239] There are also well-documented connections between oil and gas development and ozone formation in Wyoming's Upper Green River Basin and Utah's Uinta Basin, among others.[240]

***HAPs***. In addition to VOC and NOx emissions, in issuing its proposed rule, EPA recognized the negative health and welfare consequences of HAPs emitted from oil and gas extraction and the health benefits the proposed rule provides by reducing HAP emissions.[241]

### 3. *Recent Studies Suggest Proximity to Oil and Gas Development is Associated with Adverse Health Outcomes*

There are over 120 million people living in ozone non-attainment areas in the U.S. according to EPA calculations[242] and nationwide, it is estimated that almost 18 million people live within 1 mile of at least one active oil and/or gas site.[243]

New studies document associations between such proximity to nonconventional oil and gas development and negative human health effects generally. Studies have documented that living near natural gas wells is associated with lower birth weight babies[244] and preterm birth.[245] Other studies have found an association between oil and gas proximity and congenital heart defects (CHDs) in infants.[246] CHDs are the leading cause of death due to birth defects.[247] A 2014 Colorado study found that babies whose mothers had large numbers of natural gas wells within a 10-mile radius of their home had an increased risk of birth defects of the heart, compared to babies whose

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[239] Kemball-Cook, S., A. Bar-Ilan, J. Grant, L. Parker, J. Jung, W. Santamaria, J. Mathews, and G. Yarwood (2010), *Ozone impacts of natural gas development in the Haynesville Shale*, Environ. Sci. Technol., 44(24), 9357–9363, doi:10.1021/es1021137, *available at* https://www.ncbi.nlm.nih.gov/pubmed/21086985.

[240] *See* B. Rappenglück et al., *Strong wintertime ozone events in the Upper Green River basin, Wyoming*, Atmos. Chem. Phys. (2014), *available at* https://doi.org/10.5194/acp-14-4909-2014.

[241] EPA*, Regulatory Impact Analysis of the Final Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector Sources* ("EPA RIA")*,* 3-21-3-26 (October 2021).

[242] EPA, Summary Nonattainment Area Population Exposure Report (2021) https://www3.epa.gov/airquality/greenbook/popexp.html.

[243] Eliza D. Czolowsk et al., *Toward Consistent Methodology to Quantify Populations in Proximity to Oil and Gas Development: A National Spatial Analysis and Review,* 125 Envtl. Health Perspectives 6, *available at* https://doi.org/10.1289/EHP1535.

[244] *See* Stacy, et al., *Perinatal Outcomes and Unconventional Natural Gas Operations in Southwest Pennsylvania*, PLoS ONE (June 3, 2015), *available at* https://doi.org/10.1371/journal.pone.0126425.

[245] Casey et al., *Unconventional Natural Gas Development and Birth Outcomes in Pennsylvania, USA,* Epidemiology (Mar. 2016), *available at* https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4738074/.

[246] McKenzie et. al., *Birth Outcomes and Maternal Residential Proximity to Natural Gas Development in Rural Colorado,* Envtl. Health Perspectives (Jan. 28, 2014) *available at* https://ehp.niehs.nih.gov/1306722/; McKenzie et al., *Congenital Heart Defects and Intensity of Oil and Gas Well Site Activities in Early Pregnancy,* Environment International (July 28, 2019), *available at* https://www.sciencedirect.com/science/article/pii/S0160412019315429.

[247] McKenzie et. al., *Birth Outcomes and Maternal Residential Proximity to Natural Gas Development in Rural Colorado,* Envtl. Health Perspectives (Jan. 28, 2014) *available at* https://ehp.niehs.nih.gov/1306722/; McKenzie et al., *Congenital Heart Defects and Intensity of Oil and Gas Well Site Activities in Early Pregnancy,* Environment International (July 28, 2019), *available at* https://www.sciencedirect.com/science/article/pii/S0160412019315429.

mothers had no wells within 10 miles of their home.[248] A 2019 follow-up study by the same research team fortified these results.[249] Perhaps most notably, a recent study of over 1.1 million births in Pennsylvania demonstrated evidence for negative health effects (including low birth weight) from in utero exposure to fracking sites within 3 kilometers of a mother's residence, with the largest health impacts seen for in utero exposure within 1 kilometer of oil and gas sites.[250] Another recent study of 2.9 million births in California also found that among rural populations, living in proximity to higher production oil and gas development was associated with increased odds of having a low birth weight baby.[251]

Studies also document correlations between proximity to oil and gas drilling and human health effects in otherwise healthy populations. For example, a study from 2016 demonstrated that oil and gas well proximity was correlated with an increase in the likelihood of asthma exacerbations, including mild, moderate, and severe asthma attacks.[252] A 2015 study documented increased hospitalization rates in counties with a high density of oil and gas wells.[253] Similarly, other studies, including a 2017 study, have demonstrated an increase in the reporting of nasal, sinus, and migraine headaches, and fatigue symptoms in areas with high volumes of oil and gas drilling.[254]

Exposure to pollutants and the resulting health impacts can also be directly linked to the proximity of populations to oil and gas sites. Analysis carried out by the Clean Air Task Force found that 2,000 asthma-related emergency room visits and over 600 respiratory related hospital admissions nationally were due to ozone smog resulting from VOC and NOx emissions from oil and gas, and that children miss 500,000 days of school each year due to poor health associated with smog pollution.[255] A recent study published by scientists at EPA found that oil and gas emissions in 2015 could be attributed to cause 1,900 deaths in that year alone.[256]

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[248] McKenzie et. al., *Birth Outcomes and Maternal Residential Proximity to Natural Gas Development in Rural Colorado,* Envtl. Health Perspectives (Jan. 28, 2014), *available at* https://ehp.niehs.nih.gov/1306722/.

[249] McKenzie et al., *Congenital Heart Defects and Intensity of Oil and Gas Well Site Activities in Early Pregnancy,* Environment International (July 28, 2019), *available at* https://www.sciencedirect.com/science/article/pii/S0160412019315429.

[250] Currie, Janet, et al., *Hydraulic Fracturing and Infant Health: New Evidence from Pennsylvania*, Science Advances, American Association for the Advancement of Science (Dec. 1, 2017), *available at* advances.sciencemag.org/content/3/12/e1603021.

[251] Tran, Kathy V., et al. "*Residential Proximity to Oil and Gas Development and Birth Outcomes in California: A Retrospective Cohort Study of 2006–2015 Births.*" Environmental Health Perspectives 128.6 (2020): 067001.

[252] Rasmussen et al, *Association between Unconventional Natural Gas Development in the Marcellus Shale and Asthma Exacerbations,* 176 J. Am. Med. Assn. Internal Med. 1334-43 (Sept. 2016), *available at* https://www.ncbi.nlm.nih.gov/pubmed/27428612.

[253] Jemielita et al., *Unconventional Gas and Oil Drilling Is Associated with Increased Hospital Utilization Rates,* PLoS ONE (July 15, 2015), *available at* https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4503720/.

[254] *See* Tustin et al., *Associations between Unconventional Natural Gas Development and Nasal and Sinus, Migraine Headache, and Fatigue Symptoms in Pennsylvania,* 125 ENV. HEALTH PERSPECTIVES 189 (Feb. 2017), *available at* https://ehp.niehs.nih.gov/EHP281/.

[255] Clean Air Task Force, *Gasping for Breath: An analysis of the health effects from ozone pollution from the oil and gas industry* (2016).

[256] Fann, Neal, et al., *Assessing human health PM2. 5 and ozone impacts from US oil and natural gas sector emissions in 2025*, Environmental Science & Technology 52.15 (2018): 8095-8103.

An important 2019 study funded by the Colorado Department of Public Health and Environment used weather and emissions data measured in Colorado, with state of the science dispersion modeling tools to map concentrations of air toxics from 3 sizes of oil and gas fields, finding both an elevated lifetime cancer risk and non-cancer health risks for the population living in close proximity to oil and gas fields.[257] Benzene exposures from production emissions (from existing wells), and all activities combined (drilling, fracking, flow back and production), were associated with an increased lifetime risk (above one in a million) of leukemia for the average individual at 500 feet. Risks in the most exposed populations (people who live downwind and spend more time outdoors) only dropped below the one-in-a-million risk threshold after a distance of 2000 feet from the well. Exposures of benzene were more than 10 times higher than considered safe for acute exposure, a risk for blood disorders. Blood disorders can result in anemia, disturbances in clotting or the ability to fight infections, and can manifest as fatigue, nose bleeds or infections. The study also found the potential for neurotoxic effects, such as headaches, blurred vision and dizziness, from combined acute exposures of benzene and 2-ethyltoluene. The study only assessed pollution dispersion from single well pads. This potentially underestimates the risks faced by almost two-thirds of the roughly 240,000 Coloradoans living within 2000 ft of two or more well pads.

Another study in Colorado (2018) found that communities living in close proximity to oil and gas activity had higher measured exposures to HAPs and face increased risks to their health, including a heightened risk of cancer.[258] The study found that the lifetime cancer risk was 8.3 per 10,000 people for populations living within approximately 500 feet of oil and gas activity, above EPA's allowable risk. The study also found elevated levels of acute and chronic blood system and developmental risks, and acute nervous system risks for the same population. Benzene exposures contributed to 80-95% of risks across the different health effects.

#### 4. *Communities of Color Face Disproportionate Health Impacts*

The aforementioned impacts can disproportionately affect communities of color living in the vicinity of oil and gas activity. In Texas there are over 800,000 Latinos living within half a mile of an oil or gas well, in Colorado nearly 3 out of 10 people living near a well are Latino, and in California 2 out of 5 people living near a well are Latino.[259] In the U.S. overall, more than 1.81 million Latinos live within a half mile of existing oil and gas facilities and more than 1 million African Americans live within a half mile of existing natural gas facilities.[260]

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[257] *See* Carr et al., Final Report: Human Health Risk Assessment for Oil & Gas Operations in Colorado. ICF. Submitted to Colorado Department of Public Health and Environment. October 17, 2019 https://drive.google.com/file/d/1pO41DJMXw9sD1NjR_OKyBJP5NCb-AO0I/view.

[258] Lisa McKenzie et al., Ambient Non-Methane Hydrocarbon Levels Along Colorado's Northern Front Range: Acute and Chronic Health Risks, forthcoming in Envt'l Sci. & Tech. (Mar. 27, 2018), *available at* https://pubs.acs.org/doi/10.1021/acs.est.7b05983.

[259] *Latino Communities at Risk: The Impact of Air Pollution from the Oil and Gas Industry*, Clean Air Task Force (CATF), League of United Latin American Citizens (LULAC), National Hispanic Medical Association (NHMA) 2016.

[260] Clean Air Task Force, *Latino Communities at Risk: The Impact of Air Pollution from the Oil and Gas Industry* (2016) ("CATF Latino Communities") at 2; Clean Air Task Force, *Fumes Across the Fence-Line: The Health Impacts of Air Pollution from Oil & Gas Facilities on African American Communities* (2017) ("CATF African American Communities") at 4.

A recent study of almost 61 million Medicare patients conducted nationwide indicates a strong association between exposure to harmful pollutants associated with oil and gas facilities and mortality for minorities.[261]

***African Americans***. Disproportionate air pollution exposure burdens among African Americans have been implicated in racial disparities in health outcomes such as asthma[262] and cancer.[263] Approximately 13.4 percent of African American children have asthma (over 1.3 million children), compared to 7.3 percent for white children.[264] As a result of ozone increases due to natural gas emissions during the summer ozone season, African American children are burdened by 138,000 asthma attacks and 101,000 lost school days each year.[265] Over 1 million African Americans live in counties that face a cancer risk above EPA's level of concern from toxics emitted by natural gas facilities.[266]

***Latinos.*** Latinos are 51 percent more likely to live in counties with unhealthy levels of ozone than are whites.[267] Approximately 8.5 percent of Hispanic children have asthma, including 23.5 percent of Puerto Rican children.[268] As a result of ozone increases due to oil and gas emissions during the summer ozone season, Latino communities are burdened by 153,000 childhood asthma attacks and 112,000 lost school days each year.[269] Further, nearly 1.78 million Latinos live in counties that face a cancer risk above EPA's level of concern from toxics emitted by oil and gas facilities.[270] While Latinos made up 17% of the total U.S. population in 2014, they make up 20% of the population in counties with high cancer risk due to oil and gas air pollution.[271]

*Native Americans*. As EPA notes in its environmental justice analysis, Native American populations on average may be exposed to a higher concentration of ozone from oil and natural gas VOC emissions than white populations.[272] Native Americans who are part of the Navajo Nation in Utah and New Mexico and the Fort Berthold Indian Reservation are two times more likely to live within a half mile of an oil and gas faility compared to individuals in encompassing states, and those in Uintah-Ouray (Northern Ute) are 42 times more likely to be within a half mile than individuals in encompassing states.[273]

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[261] Di et al., *Air Pollution and Mortality in the Medicare Population*, NEW ENGLAND J. OF MEDICINE (June 29, 2017); Di Q, Dai L, Wang Y, Zanobetti A, Choirat C, Schwartz JD, Dominici F, *Association of short-term exposure to air pollution with mortality in older adults*, JAMA (Dec. 26, 2017); 318(24):2446-56.
[262] Hill, T.D., LeRoy, M.G., et al., 2011. Racial disparities in pediatric asthma: a review of the literature. Curr. Allergy Asthma Rep. 11 (1), 85–90; Nachman, K.E., Parker, J.D., 2012. Exposures to fine particulate air pollution and respiratory outcomes in adults using two national datasets: a cross-sectional study. Environ. Health 11 (1), 2012.
[263] Apelberg, B.I., Buckley, T.J., et al., 2005. Socioeconomic and racial disparities in cancer risk from air toxics in Maryland. Environ. Health Perspect. 113 (6), 693–699.
[264] CATF African American Communities at 8
[265] CATF African American Communities at 4
[266] *Id*. at 4.
[267] CATF Latino Communities at 4
[268] *Id.* at 5
[269] *Id*. at 3
[270] *Id.* at 3.
[271] *Id.* at 13.
[272] RIA 4-18.
[273] Clean Air Task Force, *Tribal Communities at Risk: The Disproportionate Impacts of Oil and Gas Air Pollution on Tribal Air Quality* (2018) 3.

## III. Legal Authority

### A. EPA is Authorized Under the Clean Air Act to Issue Protective Methane and VOC Controls for the Oil and Gas Sector.

#### 1. *Section 111's Framework.*

Section 111 of the Clean Air Act requires EPA to issue new source performance standards for listed categories of stationary sources.[274] Standards of performance are "standard[s] for emissions of air pollutants which reflect[] the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."[275] However, "if in the judgment of the Administrator, it is not feasible to prescribe or enforce a standard of performance, he may instead promulgate a design, equipment, work practice, or operational standard, or combination thereof."[276] Furthermore, section 111(h)(5) makes clear that "[a]ny design, equipment, work practice, or operational standard, or any combination thereof, described in this subsection shall be treated as a standard of performance for purposes of the provisions of this chapter (other than the provisions of subsection (a) and this subsection)."[277] Thus, throughout these comments, all references to "standards of performance" also encompass design, equipment, work practice, or operational standards (which, hereafter, we will refer to simply as "work practice standards" for the sake of simplicity).

No less than once every eight years, EPA must "review and, if appropriate, revise such standards following the procedure required by this subsection for promulgation of such standards."[278] In addition, once EPA has issued standards of performance covering new sources in a given category, it must issue emission guidelines for each existing source in that category "to which a standard of performance under this section would apply if such existing source were a new source."[279] Under section 111(d)(1), EPA's guidelines may only cover emissions of pollutants that are neither regulated under section 108-110's national ambient air quality standards ("NAAQS") program nor under section 112's hazardous air pollutant ("HAP") program.[280] Once EPA has issued emission guidelines for a particular category's existing sources, states issue plans that establish performance standards for sources within their borders that are "no less stringent" than EPA's guidelines.[281] However, EPA's guidelines "shall permit the State in applying a standard of performance to any

[274] 42 U.S.C. § 7411(b)(1)(B).
[275] *Id.* § 7411(a).
[276] *Id.* § 7411(h)(1).
[277] *Id.* § 7411(h)(5).
[278] *Id.*
[279] *Id.* § 7411(d)(1).
[280] *Id.*
[281] 40 C.F.R. § 60.24a(c); 42 U.S.C.§ 7411(d)(1).

particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."[282]

As noted above, Section 111(a)(1) requires performance standards for both new and existing sources to reflect "the degree of emission limitation achievable through the application of the best system of emission reduction"—or BSER—"which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."[283] Work practice standards, which do not establish numerical emission limitations but actions, practices, or equipment that sources must use to reduce emissions, must reflect "the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."[284] As EPA notes in the OOOOb and c preamble, while the differences between a "system of emission reduction" and a "technological system of continuous emission reduction" may be meaningful in other contexts, for purposes of evaluating the sources and systems of emission reduction at issue [for the oil and gas source category], the EPA has applied these concepts in an essentially comparable manner."[285] Thus, throughout these comments, any reference to the best system of emission reduction or BSER should be understood to encompass the best technological system of continuous emission reduction as well.

EPA's designation of the BSER cannot achieve merely nominal or marginal emission reductions; it must cut pollution as much as feasible. In *Sierra Club v. Costle*, 657 F.2d 298, 326 (D.C. Cir. 1981), the D.C. Circuit held that "we can think of no sensible interpretation of the statutory words 'best technological system'[286] which would not incorporate the amount of air pollution as a relevant factor to be weighed when determining the optimal standard for controlling . . . emissions." The court also rejected an argument that "'EPA may not consider total air emissions in deciding on a proper NSPS'" with the explanation that "this position [is] untenable given that one of the agreed upon legislative purposes . . . *requires* that the standards must maximize the potential for long term economic growth 'by reducing emissions *as much as practicable*.'"[287]

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[282] 42 U.S.C. § 7411(d)(1).
[283] *Id.* § 7411(a).
[284] *Id.* § 7411(h)(1).
[285] 86 Fed. Reg. at 63,133 n.94.
[286] As discussed below, in 1977 Congress amended section 111(b) to require new source standards reflecting "the best technological system of continuous emission reduction." Clean Air Act Amendments of 1977, Pub. L. No. 95-95, § 109(c)(1)(A), 91 Stat. 685, 699-700. In 1990, Congress restored the original "best system of emission reduction" for this provision. Clean Air Act Amendments of 1990, Pub. L. No. 101-549, § 403(a), 104 Stat. 2399, 2631. This change had important implications for EPA's authority to include non-technological factors in a BSER determination. However, under both the BSER and "best technological system" language, EPA must take into account the quantity of air pollution reductions that its chosen system would achieve.
[287] *Id.* (emphasis added); *see also* 42 U.S.C. § 7401(b) (the Clean Air Act's fundamental purpose is "to protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population." Three additional purposes are itemized, all of which aim to achieve "the prevention and control of air pollution." 42 U.S.C. § 7401(b). *See also* Summary of the Provisions of Conference Agreement on Clean Air Act Amendments of 1970, 116 Cong. Rec. 42,385 (Dec. 18, 1970) (sources regulated under section 111 "must be controlled to the maximum practicable degree regardless of location").

To fulfill its duty to maximize emission reductions, EPA must (as discussed above) establish performance standards for new sources that reflect the "best system of emission reduction," or BSER.[288] The text of section 111 and governing legal decisions interpreting it make clear that in designating BSER, EPA must first identify the various "systems of emission reduction" that have been "adequately demonstrated" for a given source category.[289] Of those systems, it must then select the "best," taking into account the "extent of emission reduction" achieved by the system," "costs," "nonair quality health and environmental impacts," "energy requirements," and "technological innovation."[290] Lastly, EPA must set the standard at a level that is "achievable"[291] but reflects the "maximum practicable degree" of "control[]."[292]

The D.C. Circuit has made clear that section 111 is a "technology-forcing statute." In this regard, when selecting the best system, EPA must look broadly at systems and techniques that may be in use in other, comparable industrial sectors; consider future improvements and refinements in emission reduction systems; and consider systems that are not necessarily in "actual, routine use somewhere."[293] Although EPA may not designate "purely theoretical or experimental means of preventing or controlling air pollution" as the BSER, or rely on a "crystal ball inquiry" to make its determination, it must reasonably "look[] toward what may fairly be projected for the regulatory future, rather than the state of the art at present." [294]

With regard to section 111's cost factor, courts will uphold EPA's designation of the BSER so long as it is not "exorbitantly costly in an economic or environmental way"[295] or "unreasonable."[296]To that end, the agency need only ensure that the costs related to the BSER are not "greater than the industry could bear and survive."[297] Therefore, EPA must consider whether the industry as a whole – not an individual affected source or company – is able to "adjust itself in a healthy economic fashion" in achieving the emission reductions associated with the BSER.[298] Thus, EPA may not calibrate the stringency of the BSER based on the economic impacts on any specific source or sources, but must consider the entire oil and gas source category. For convenience and because it considers several cost-effectiveness formulations established by courts

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[288] 42 U.S.C. § 7411(a)(1).
[289] *See, e.g.*, 83 Fed. Reg. at 65,433-34 (expounding upon 42 U.S.C. § 7411(a)(1) and citing relevant cases, including *Costle*, 657 F.2d at 326, 343, 346-7, *Lignite Energy Council v. EPA*, 198 F. 3d 930, 933 (D.C. Cir. 1999), *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973), and *Portland Cement Ass'n v. EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975)).
[290] 83 Fed. Reg. at 65,433-34.
[291] *Id.*
[292] 116 Cong. Rec. at 42,385.
[293] *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973); *see also* H. Rep. No. 91-1146, 91st Cong., 2d Sess. 10 (1970).
[294] *Id. See also ASARCO Inc. v. EPA*, 578 F.2d 319, 322 & 322 n.6 (D.C. Cir. 1978) (best system standard is designed to "*enhance* air quality and not merely to maintain it") (emphasis added); *Costle*, 657 F.2d at 347 n.174 (Congress's intent in enacting section 111 was "to induce, to stimulate, and to augment the innovative character of industry in reaching for more effective, less costly systems to control air pollution").
[295] *Essex Chemical Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973).
[296] *Sierra Club v. Costle*, 657 F.2d 298, 343 (D.C. Cir. 1981).
[297] *Portland Cement Ass'n v. EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975); *see also Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999) ("EPA's choice will be sustained unless the environmental or economic costs of using the technology are exorbitant.").
[298] *Portland Cement*, 513 F.2d at 508.

to be synonymous, EPA has decided, as it has in previous rulemakings, to use "reasonableness" as a standard for determining cost-effectiveness, meaning that a control measure may be considered the "best system of emission reduction…adequately demonstrated" if its costs are reasonable for the industry, but not if they would be unreasonable.[299]

Section 111 does not specify a particular manner in which EPA must evaluate costs, and the case law makes clear that the statute does not require a formal cost-benefit balancing test.[300] As discussed in the preamble, EPA has historically used a number of metrics for evaluating the reasonableness of costs for its proposed best system, including an analysis of the standard's compliance costs for each ton of pollutant reduced (evaluated on both a single pollutant basis, with all costs assigned to reductions of one regulated pollutant, and on a multipollutant basis, with costs distributed across reductions of multiple regulated pollutants); an evaluation of those costs in comparison to the industry's overall capital spending; and an evaluation of costs in comparison to the industry's overall revenues.[301] For this industry, EPA also assesses costs in light of cost savings to operators due additional revenue earned through the sale of captured gas that would otherwise have been emitted.

In the proposal, EPA considers cost-effectiveness values of up to $5,540/ton of VOC reduced to be reasonable based on precedents set in past EPA rulemakings.[302] EPA also finds that control measures with costs of up to $1,800/ton of methane reduced are cost-effective and thus reasonable in this proposal, although it mentions in multiple instances in the preamble that in 2016's OOOOa rulemaking, the agency found that measures costing up to $2,185/ton of methane reduced were reasonable.[303]

As discussed in more detail below in these comments, the current interim global social cost of methane provides an estimate of the cost that each additional metric ton of methane pollution imposes on society by driving climate change. The current interim global social cost figure likely significantly underestimates the true cost of methane pollution, for reasons discussed in detail in Section VI and acknowledged by EPA.[304] Nevertheless, this metric provides an appropriate *minimum* benchmark for determining the costs that may be considered reasonable with regard to the cost per ton of pollution abated and offers additional support for EPA's determination that the costs of the proposed standards are reasonable overall. Indeed, much higher costs per ton of methane reduction are likely also reasonable once the full set of harms caused by methane are properly accounted for.

When considered in light of these metrics, the proposed standards and emission guidelines are reasonable and thus easily meet section 111's cost requirement. However, as we discuss in more detail in later sections of this letter, EPA could – and should – increase the stringency of the rulemaking in numerous regards while avoiding unreasonable costs. The agency therefore must

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[299] 86 Fed. Reg. at 63,133.
[300] *See, e.g.*, *Essex Chem. Corp.*, 486 F.2d at 437 (cost-benefit analysis was not required for acid mist standards).
[301] *See* 86 Fed. Reg. at 63,154.
[302] *Id.* at 63,155.
[303] *Id.*
[304] RIA at 3-13.

consider whether its historical benchmark for determining the per-ton cost-effectiveness threshold for methane reductions should be adjusted upward.

Furthermore, the measures that EPA includes in a BSER determination are not limited to bolt-on control devices, but may also encompass industrial *process* factors such as methods of production.[305] In fact, not only may EPA set standards that reflect certain production processes and not others, it may effectively eliminate higher-polluting processes so long as alternative processes are available and are not unreasonably costly.[306] Furthermore, the lower-emitting processes need not be "[less] onerous than those which would be associated with controlling the process under a less stringent standard."[307] For example, in its NSPS for primary copper, zinc, and lead smelters, EPA established emission limits that effectively eliminated the practice of reverberatory copper smelting in most circumstances because the lower-polluting process of flash copper smelting was available at an economically reasonable cost.[308]

Indeed, where EPA allows a certain high-polluting practice to continue in NSPS without good reason, that decision is arbitrary and capricious. For instance, in *State of New York v. Reilly*, the D.C. Circuit rejected EPA's decision not to effectively eliminate the combustion of lead-acid vehicle batteries in its performance standards for municipal waste combustors ("MWCs").[309] EPA had admitted that the combustion of these batteries was "a significant source of lead in MWC emissions," and that "a ban [on their combustion] would achieve air benefit[s]," but nonetheless selected a more lenient standard that did not prohibit this practice.[310] Because the agency had not justified its decision to adopt the weaker standard, the court remanded the rule to the agency as unlawful.[311]

Moreover, not only may section 111 standards effectively eliminate certain higher-emitting processes, but they may be set at a level that would allow for *no* emissions from the source in question. Under section 111(a)(7), the term "technological system of continuous emission reduction"—which, under section 111(h)(1), informs EPA's work practice standards—includes "a technological process for production or operation by any source which is *inherently low-polluting or nonpolluting*."[312] (emphasis added). This leaves no doubt that Congress quite intentionally granted EPA the authority to include non-emitting technology as the basis for section 111 standards where appropriate. Although section 111 does not include a separate definition for "system of emission reduction," which informs EPA's selection of numerical performance standards (as distinguished from non-numerical work practice standards), it is clear that the range

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[305] *See* n. 286, *supra*, discussing Congress's conscious decision in the 1990 amendments to abolish the requirement that section 111 standards for new sources be limited to "technological" measures.
[306] *See, e.g.,* EPA, Office of General Counsel, Legal Memorandum: Authority to Prescribe Processes (Sept. 28, 1973), 1973 WL 21924, at *1 ("[W]here the application of a standard to a given process would effectively ban the process," EPA need not establish a separate, more lenient standard for the banned process so long as "some other process(es) is (are) available to perform the function at reasonable cost.").
[307] *Id.*
[308] 41 Fed. Reg. 2,332, 2,333-34 (Jan. 15, 1976). *See also* 79 Fed. Reg. 1430, 1467 (Jan. 8, 2014) (proposed rule for current $CO_2$ NSPS for fossil fuel-fired power plants) (citing example of copper smelter NSPS).
[309] 969 F.2d 1147, 1153 (D.C. Cir. 1992).
[310] *Id.*
[311] *Id.*
[312] 42 U.S.C. § 7411(a)(7).

of options for any "system of emission reduction" would necessarily include, and would potentially extend beyond, those options available for the more precisely defined "technological system of continuous emission reduction."[313] And, as noted above, EPA is within its authority to consider these two terms as functionally interchangeable for the purpose of oil and gas sector regulations. Thus, regardless of which of these "systems" EPA is considering, it may designate a non-emitting technological process as the "best" system, provided it is within the parameters of section 111's other factors.

In short, section 111 standards must reduce air pollution as much as practicable within the parameters of what is achievable, adequately demonstrated, and not exorbitantly costly.[314] EPA must also advance innovation by looking to the technological future, not the past, and must consider non-emitting processes where they are available and consistent with the BSER factors. As we will discuss throughout these comments, all of the standards that EPA has proposed for the oil and gas sector in its OOOOb and c proposal are easily achievable, adequately demonstrated, economically reasonable, and consistent with the need for technological innovation. We do, however, believe that EPA must achieve still greater emission reductions in a number of specific areas of the oil and gas sector consistent with section 111's requirements. Later in this comment document, we will describe our recommendations for how EPA should lawfully increase the protectiveness of its proposed standards and emission guidelines to more fully safeguard the public against climate and health injuries resulting from oil and gas pollution.

### 2. *EPA's History of Regulating Oil and Gas Emissions Under Section 111*

The OOOOb and c rulemakings represent EPA's latest action to control emissions from a source category that the agency has regulated for decades under section 111. In 1979, EPA first listed "Crude Oil and Natural Gas Production" under section 111(b)(1)(A) as a stationary source category that causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.[315] The agency made this listing decision in response to a Congressional command to expeditiously list priority categories of stationary sources that emit pollutants endangering human health and welfare.[316] Despite section 111(b)(2)'s requirement that EPA propose standards of performance within one year of listing a source category and finalize standards within one year of that proposal, the agency did not actually

[313]Thus, when discussing the theoretical differences between a system of emission reduction and a technological system of continuous emission reduction, EPA explains that "[a]lthough the differences in these phrases may be meaningful in other contexts, for purposes of evaluating the sources and systems of emission reduction at issue [for the oil and gas source category], the EPA has applied these concepts in an essentially comparable manner." 86 Fed. Reg. at 63,133 n. 94.
[314] *Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999).
[315] 44 Fed. Reg. 49,222, 49,226 (Aug. 21, 1979).
[316] *Id.* at 49,222 (citing 42 U.S.C. § 7411(f)).

regulate oil and gas sources until 1985, when it issued VOC and $SO_2$ standards for gas processing plants.[317][318]

Although the Clean Air Act requires EPA to review and (if appropriate) revise a source category's performance standards no less frequently than every eight years,[319] the agency failed to review its oil and gas source standards until August 2011, when it proposed additional requirements for this sector targeting emissions of VOC from the production, processing, transmission and storage segments of the industry.[320] EPA also acknowledged in that proposal that "processes in the Oil and Natural Gas source category emit significant amounts of methane," and that such emissions are equivalent to more than 328 million metric tons of carbon dioxide each year.[321] However, EPA did not propose any standards for methane emissions, despite having previously determined in 2009 that methane and other greenhouse gases endanger public health and welfare.[322]

In August 2012, EPA issued a final rule (the OOOO rule) revising some aspects of the proposed VOC standards, but declining to establish methane standards for the sector, stating that EPA "intend[ed] to continue to evaluate the appropriateness of regulating methane with an eye toward taking additional steps if appropriate."[323] A group of environmental NGOs—including many of the Joint Environmental Commenters—filed litigation in the D.C. Circuit objecting to (among other issues) the agency's failure to issue methane standards for this sector under section 111(b), but concurrently defended the agency's VOC standards against attacks from industry groups and others who deemed them unlawful.[324] After the agency subsequently granted the NGOs' petition for and initiated reconsideration of the methane question and other issues related to the OOOO rule, the petitions for judicial review were placed in abeyance, where they have remained since 2013.[325]

In June 2013, EPA released for public comment and peer review five technical white papers[326] regarding sources of and mitigation techniques to control methane and VOC emissions in the oil and natural gas sector. In September 2015, EPA proposed long-overdue methane standards for

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[317] The fact that EPA's initial NSPS for this source category addressed gas *processing plant* emissions makes clear that the reference to oil and gas "*production*" in the source category's title was never intended to limit that category just to equipment in the production segment like wellheads and gathering and boosting compressor stations. Rather, EPA intended for the regulated source category to include the oil and gas industry broadly defined, as we discuss in more detail in Part III.C below.

[318] *See* 50 Fed. Reg. 26,122 (June 24, 1985) (VOC standards); 50 Fed. Reg. 40,158 (Oct. 1, 1985) (SO2 standards).

[319] 42 U.S.C. § 7411(b)(1)(A).

[320] 76 Fed. Reg. 52,738 (Aug. 23, 2011).

[321] *Id.* at 52,756.

[322] *See* 74 Fed. Reg. at 66,496.

[323] 77 Fed. Reg. 49,490, 49,513 (Aug. 16, 2012).

[324] *See* Statement of Issues, Doc. No. 1405564, ¶ 7, Natural Resources Defense Council, et al. v. EPA, No. 12-1409 (D.C. Cir. Nov. 16, 2012); Joint Mot. of Envtl. Pet'rs. To Intervene on Behalf of Respondents, Doc. No. 1405110, American Petroleum Institute vs. EPA, No. 12-1405 (D.C. Cir. Nov. 14, 2012).

[325] *See* Order, Doc. No. 1428803, *American Petroleum Institute vs. EPA*, No. 12-1405 (D.C. Cir. Apr. 3 2013).

[326] These five white papers, which address compressors, gas well completions and associated gas during production, equipment leaks, liquids unloading, and pneumatic devices, are available at https://web.archive.org/web/20150221161004/http://www.epa.gov/airquality/oilandgas/whitepapers.html (last visited Jan. 28, 2022). In the Appendix, the five white papers can be found individually by finding the filenames starting with "EPA_White Paper."

new oil and gas equipment in the production, processing, transmission, and storage segments, as well as updated VOC standards that operated in parallel with the methane controls.[327]

On June 3, 2016, EPA promulgated final performance standards for methane and VOC emissions from new and modified oil and natural gas sources (the OOOOa rule). Among other things, the OOOOa rule required reduced emission completions at fracked or re-fracked wells. Although the agency did not concurrently propose or finalize guidelines for limiting such emissions from existing oil and natural gas sources, it recognized its legal obligation to do so. Accordingly, on the same day that it issued the 2016 Rule, EPA published notice that it would be issuing an information collection request ("ICR") directed toward existing sources and their emissions.[328] On November 10 of that year, the agency issued the final ICR.[329] In addition, a few weeks prior, EPA issued VOC control techniques guidelines (CTGs) for the oil and gas sector pursuant to sections 108, 172, 182, and 184 of the Clean Air Act.[330] EPA's guidelines established a presumptive level of reasonably available control technology for VOC emissions from existing oil and gas sources. States to which these guidelines were applicable included oil- and gas-producing states with moderate, serious, severe, or extreme ozone nonattainment areas, as well as oil- and gas-producing states in the ozone transport region.

In January 2017, the new administration initiated a sharp reversal of policy in EPA's approach to regulating oil and gas air emissions. In March 2017, EPA Administrator Scott Pruitt withdrew the ICR without requesting notice and comment.[331] He then initiated a reconsideration proceeding for the OOOOa and implemented a 90-day stay of, among other things, the rule's leak detection and repair ("LDAR") requirements.[332] Administrator Pruitt cited section Clean Air Act section 307(d)(7)(B) for authority and declined once again to solicit public comment.[333] Many of the Joint Commenters immediately brought suit in the U.S. Court of Appeals for the D.C. Circuit, alleging that the Administrator had provided no legitimate basis under section 307(d)(7)(B) to justify the stay. The Court agreed, finding the stay "arbitrary, capricious, and . . . in excess of its . . . statutory . . . authority," and vacated it on those grounds.[334]

While the Court's decision was pending, the Trump EPA issued two proposals (this time submitted for public comment) suspending OOOOa's LDAR standards and other requirements for three

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[327] 80 Fed. Reg. 56,593 (Sept. 18, 2015).
[328] 81 Fed. Reg, 35,763 (June 3, 2016).
[329]EPA Information Collection Request Supporting Statement, Information Collection Effort for Oil and Gas Facililties, EPA ICR No. 2548.01(Nov. 9, 2016), available at https://www.epa.gov/sites/default/files/2016-11/documents/oil-natural-gas-icr-supporting-statement-epa-icr-2548-01.pdf.
[330] EPA, Control Techniques Guidelines for the Oil and Natural Gas Industry (Oct. 2016), a*vailable at* ; *see also* 81 Fed. Reg. 74,798 (Oct. 27, 2016); *see also* 42 U.S.C. §§ 7408(b)(1), 7502(c)(1), 7511a(b)(2)(A), 7511a (c), 7511a (d), 7511a (e), § 7511c(b)(1)(B).https://www.epa.gov/sites/default/files/2016-10/documents/2016-ctg-oil-and-gas.pdf; *see also* 81 Fed. Reg. 74,798 (Oct. 27, 2016); *see also* 42 U.S.C. §§ 7408(b)(1), 7502(c)(1), 7511a(b)(2)(A), 7511a (c), 7511a (d), 7511a (e), § 7511c(b)(1)(B).
[331] 82 Fed. Reg. 12,817 (March 7, 2017).
[332] 82 Fed. Reg. 25,730 (June 5, 2017).
[333] *Id.* (citing 42 U.S.C. 7607(d)(7)(B)).
[334] *Clean Air Council v. Pruitt*, 862 F.3d 1, 14 (D.C. Cir. 2017) (citing 42 U.S.C. § 7607(d)(9)(A), (C)) (internal quotations and brackets omitted).

months and an additional two years, respectively.[335] The following March, the agency proposed to withdraw the 2016 oil and gas CTGs, citing its reconsideration of the OOOOa rule as its only justification.[336] Joint Environmental Commenters vigorously opposed all three proposals and submitted detailed technical and legal comments explaining the many ways in which they violated the Clean Air Act and were arbitrary and capricious.

EPA never finalized any of these three rule proposals. However, it subsequently proposed—and in the fall of 2020 finalized—two rules known commonly as the "Methane Policy Rule" and the "Methane Technical Rule."[337] The Methane Policy Rule implemented two major changes to the OOOOa rule. First, it rescinded all methane and VOC standards applicable to transmission and storage equipment, claiming that the 1979 source category listing covered only the production and processing segments of the industry.[338] EPA also argued that the agency's early action in 2016 to amend the source category definition to include transmission and storage equipment was invalid because those sources were "not sufficiently related' to production and processing equipment.[339]

Second, EPA rescinded the methane standards for the equipment that still remained in the source category definition (i.e., production and processing equipment), leaving only VOC standards on the books.[340] EPA reasoned that OOOOa's methane standards were "unnecessary insofar as they impose redundant requirements" with the VOC standards, dismissing as a mere "legal consequence" the fact that only its methane controls for new sources—and not VOC controls—can establish a legal predicate for regulating existing oil and gas sources under section 111(d).[341] The Agency further asserted that even if such requirements were not redundant, EPA had not properly determined in 2016 that methane emissions from this source category "significantly contribute" to dangerous air pollution, and could not issue such a determination in the absence of a more-defined "intelligible standard or threshold for determining when an air pollutant contributes significantly to dangerous air pollution."[342]

EPA's Methane Technical Rule did not address the agency's underlying regulatory authority over the oil and gas source category, but instead made a number of amendments to the control requirements included in the OOOOa rule. Because the agency finalized the Policy Rule the day before it issued the final Technical Rule, the latter's amendments applied only to those standards that had not been rescinded—that is, VOC controls for the production and processing segments Of particular note, the Technical Rule rescinded LDAR requirements for VOC emissions from oil and gas wells that produce 15 barrels of oil per day equivalents based on a 12-month rolling average.[343] The Technical Rule also revised the required frequency of LDAR inspections at gathering and

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[335] 82 Fed. Reg. 27,642 (June 16, 2017); 82 Fed. Reg. 27,645 (June 16, 2017).
[336] 83 Fed. Reg. 10,478 (Mar. 9, 2018).
[337] 84 Fed. Reg. 50,244 (Sept. 24, 2019) (proposed Methane Policy Rule); 85 Fed. Reg. 57,018 (Sept. 14, 2020) (final Methane Policy Rule); 83 Fed. Reg. 52,056 (Oct. 15, 2018) (proposed Methane Technical Rule); 85 Fed. Reg. 57,399 (Sept. 15, 2020) (final Methane Technical Rule).
[338] 85 Fed. Reg. at 57,024.
[339] *Id.* at 57,046.
[340] *Id.* at 57,019.
[341] *Id.* at 57,019.
[342] *Id.* at 57,038.
[343] 85 Fed. Reg. at 57,405.

boosting compressor stations from quarterly to semi-annually.[344] In both cases, EPA asserted that the OOOOa requirements for these sources were not justified from a cost-effectiveness standpoint.[345]

Joint Environmental Commenters immediately filed lawsuits in the D.C. Circuit challenging both the Policy and Technical Rules.[346] Before either case was fully briefed on the merits, the Biden Administration took office and the president immediately ordered EPA both to review the prior administration's regulatory rollbacks for the oil and gas sector and to consider initiating a rulemaking to propose existing source requirements for the sector.[347] The following month, the D.C. Circuit granted EPA's motions to hold both cases in abeyance while EPA reviewed the rules.[348]

On June 30, 2021, President Biden signed into law a Congressional Review Act ("CRA") resolution passed by both houses of Congress disapproving the prior administration's Methane Policy Rule.[349] As a result, the Policy Rule was "made of no force or effect" and "shall be treated as though [it] had never taken effect," and EPA is now prohibited from issuing "a new rule that is substantially the same as" the Policy Rule in the absence of new legislation authorizing it. 5 U.S.C. § 801(f), (b)(2). Accordingly, OOOOa's requirements that had been rescinded by the Policy Rule—methane and VOC standards for transmission and storage equipment and methane standards for production and processing equipment—were immediately restored.[350] Furthermore, those restored standards were not affected by the amendments implemented by the later-promulgated Technical Rule, which only applied to VOC standards for production and processing equipment.[351] As a result of the methane CRA resolution, the litigation over the Policy Rule was rendered moot, and the D.C. Circuit granted petitioners' motion for voluntary dismissal.[352] The litigation over the Technical Rule, which was not directly affected by the methane CRA resolution, remains in abeyance.

On November 15, 2021, after extensive outreach and consultation with stakeholders, and in response to Executive Order 13,990, EPA issued the OOOOb and c rule proposals, which amended OOOOa's new source methane and VOC standards for the oil and gas sector and established

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[344] *Id.* at 57,412.
[345] *Id.* at 57,418-21.
[346] *See Environmental Defense Fund, et al. v. Andrew Wheeler et al.* [original caption], No. 20-1359 (D.C Cir.) (consolidated under *State of California, et al. v. Andrew Wheeler, et al.* [original caption], No. 20-1357 (D.C. Cir.)) (Policy Rule challenge); *Environmental Defense Fund, et al. v. Andrew Wheeler, et al.* [original caption], No. 20-1360 (D.C Cir.) (Technical Rule challenge).
[347] Protecting Public Health and the Environment and Restoring Science To Tackle the Climate Crisis, Exec. Order. No. 13,990, §§2(a)(i), (c)(i), 86 Fed. Reg. 7,037 (Jan. 20, 2021).
[348] Order, *State of California, et al. v. Andrew Wheeler, et al.*, Doc. No. 1885114, No. 20-1357 (D.C Cir. Feb. 12, 2021) (holding Policy Rule lawsuit in abeyance); Order, *Environmental Defense Fund, et al. v. Andrew Wheeler, et al.*, Doc. No. 1886335, No. 20-1360 (D.C Cir. Feb. 19, 2021) (holding Technical Rule lawsuit in abeyance).
[349] Pub. L. No. 117-23 (June 30, 2021).
[350] *See* 86 Fed. Reg. at 63,136-37.
[351] *Id.* at 63,137.
[352] Order, *State of California, et al. v. Andrew Wheeler, et al.*, Doc. No. 1911434, No. 20-1357 (D.C Cir. Aug. 25, 2021).

emission guidelines for existing sources. This submission represents Joint Environmental Commenters' technical and legal views of the OOOOb and c proposals.

3. *Under Section 111, EPA is Authorized to Regulate Greenhouse Gas Emissions from Oil and Gas Sources, With Methane as the Designated Pollutant.*

There is no question that EPA is authorized to regulate greenhouse gas emissions under section 111 of the Clean Air Act. In *Massachusetts v. EPA*,[353] the Supreme Court held that the statute's general definition of "air pollutant" appearing at 42 U.S.C § 7602(g) includes greenhouse gases, a finding it reaffirmed in *Utility Air Regulatory Group v. EPA* ("*UARG*").[354] The Court further ruled unanimously in *American Electric Power Company v. Connecticut* that section 111 of the Clean Air Act in particular "speaks directly" to greenhouse gas regulation, and that in enacting this provision, "Congress designated . . . EPA . . . as best suited to serve as primary regulator of greenhouse gas emissions."[355]

In fact, in *Massachusetts*, the Court made clear that EPA *must* regulate sources' greenhouse gas emissions—new motor vehicles, in that case—unless "it determines that greenhouse gases do not contribute to climate change or if it provides some reasonable explanation as to why it cannot or will not exercise its discretion to determine whether they do."[356] Following the Court's instructions, in 2009, EPA concluded that emissions of six well-mixed greenhouse gases from mobile sources—including methane—do, indeed, "cause or contribute to, air pollution which may reasonably be anticipated to endanger public health or welfare."[357] The Endangerment Finding was made after an extraordinarily thorough scientific review and careful consideration of public comments. It was reaffirmed after full consideration of petitions for reconsideration and was upheld in its entirety by the D.C. Circuit in the face of a vigorous industry challenge.[358] The court found that the Endangerment Finding was procedurally sound, consistent with Supreme Court case law, and amply supported by the administrative record, observing that "[t]he body of scientific evidence marshaled by EPA in support of the Endangerment Finding is substantial."[359] And while it granted certiorari on one component of the D.C. Circuit's holding in *CRR I*, the Supreme Court declined to review any aspect of the lower court's holding on the Endangerment Finding.[360]

The 2009 Finding fully satisfies any requirement for an endangerment determination under section 111, not only for the OOOOa rule and these OOOOb and c proposals, but for any other listed source category for which EPA may set greenhouse gas standards going forward. EPA made very

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[353] 549 U.S. 497, 529 (2007).
[354] 573 U.S. 302, 316 (2014).
[355] 564 U.S. 410, 424, 428 (2011).
[356] *Massachusetts*, 549 U.S. at 533.
[357] Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, 74 Fed. Reg. 66,496 (Dec. 15, 2009) ("the Endangerment Finding").
[358] *Coal. for Responsible Regulation, Inc. v. EPA (CRR I)*, 684 F.3d 102, 116-27 (D.C. Cir. 2012), *aff'd in part, rev'd in part sub nom. Util. Air Regulatory Grp. v. EPA*, 134 S. Ct. 2427 (2014) *and amended sub nom. Coal. for Responsible Regulation, Inc. v. EPA (CRR II)*, 606 F. App'x 6 (D.C. Cir. 2015).
[359] *Id.* at 120.
[360] *See Util. Air Regulatory Grp. v. EPA*, 134 S. Ct. 418, 2013 U.S. LEXIS 7380 (Oct. 15, 2013).

clear in 2009 that the endangerment component of its finding rule applied generally to the sum total of all anthropogenic greenhouse gas "air pollution," irrespective of the sources from which the individual "air pollutants" were emitted.[361] This distinction originates in the Clean Air Act itself. Section 202(a)(1) provides that

> [t]he Administrator shall by regulation prescribe (and from time to time revise) in accordance with the provisions of this section, standards applicable to the emission of any *air pollutant* from any class or classes of new motor vehicles or new motor vehicle engines, which in [her] judgment cause, or contribute to, *air pollution* which may reasonably be anticipated to endanger public health or welfare.[362]

Thus, the statutory provision applied in the 2009 Endangerment Finding required EPA to consider whether "air pollution" may reasonably be anticipated to endanger, not the "pollutant" itself. As EPA explained,

> to help appreciate the distinction between air pollution and air pollutant, the *air pollution* can be thought of as the total, cumulative stock in the atmosphere, while the *air pollutant* can be thought of as the flow that changes the size of the total stock.[363]

EPA therefore determined in 2009 that the "total, cumulative stock" of GHGs—not just mobile source emissions—could reasonably be anticipated to endanger public health and welfare. And as the Endangerment Finding makes clear, the total, cumulative stock of GHGs includes atmospheric methane resulting from man-made activities. In the Finding, EPA cites methane as the second-largest well-mixed GHG on a $CO_2$-equivalent basis, after carbon dioxide itself.[364] EPA further notes that "[t]he global atmospheric concentration of methane has increased by 149 percent since pre-industrial levels (through 2007)[,] . . . [and] [t]he observed concentration increase in th[is] gas[] can . . . be attributed primarily to anthropogenic emissions."[365] In comparison, global concentrations of carbon dioxide have increased by 38 percent since pre-industrial times and nitrous oxide by 23 percent—large increases, to be sure, but several times smaller than the corresponding percentage increase in atmospheric methane.[366]

As discussed in detail in Part II above, the scientific research conducted in the 12 years since the Endangerment Finding was issued has not merely reaffirmed the Finding's fundamental conclusion, but has made clear that climate change is much more dire—and that deep and immediate cuts to anthropogenic greenhouse gas emissions are much more urgently needed—than was understood even a decade ago. And as discussed in Parts II and IV.A, research conducted after

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[361] *See, e.g.*, 74 Fed. Reg. 66,496, 66,506 (Dec. 15, 2009) ("[T]he Administrator is to consider *the cumulative impact* of sources of a pollutant in assessing the risks from air pollution, and is not to look only at the risks attributable to a single source or class of sources.").
[362] 42 U.S.C. § 7521(a)(1) (emphasis added).
[363] 74 Fed. Reg. at 66,536 (emphasis in original).
[364] *Id.* at 66,549.
[365] *Id.* at 65,517.
[366] *Id.*

EPA issued the OOOOa rule in 2016 demonstrates that methane emissions, in particular from the oil and gas sector, are not only enormous, but are markedly higher than previous estimates (including EPA's) suggested. While EPA need only articulate a rational basis for issuing methane regulations from this source category under section 111, it would be justified in issuing such regulations even if it *were* required (which it is not) to formally determine that an individual pollutant emitted by a source category significantly contributes to dangerous pollution.[367] There can thus be no legitimate dispute that, consistent with *Massachusetts*, *UARG*, and *American Electric Power*, EPA not only *may* regulate oil and gas methane emissions under section 111, but *must* do so.

Although the Endangerment Finding technically addresses a pollutant it defines as "the mix of six long-lived and directly-emitted greenhouse gases"—carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluorides[368]—EPA is well within its authority to regulate methane in particular as the designated pollutant. In *American Electric Power*, the Supreme Court left no doubt that EPA may, under section 111, regulate specific greenhouse gases (carbon dioxide, in that case) among the six well-mixed pollutants that were the subject of the 2009 Endangerment Finding.[369]

Furthermore, as discussed in more detail below, EPA correctly determined in the OOOOa rulemaking that the quantity of methane emitted by the oil and gas source category easily qualifies as "significant" under any reasonable definition. Although the agency asserted in OOOOa that it need not make such a pollutant-specific significant finding in order to issue section 111 standards, and the House Report accompanying the 2021 Congressional Review Act resolution affirmed that position, the record leaves no doubt that oil and gas sector methane emissions are "significant" in any event. Thus, under any feasible interpretation of section 111, EPA may thus issue greenhouse gas regulations for the oil and gas sector in the form of methane standards.

4. *EPA's Section 112 Regulations for the Oil and Gas Sector Do Not Limit the Agency's Authority to Issue Methane Emission Guidelines for Existing Oil and Gas Sources Under Section 111(d).*

In 2012, EPA issued the OOOO rule, which greatly expanded the section 111(b) VOC standards for the oil and gas sector, alongside two sets of section 112 national emission standards for hazardous air pollutants ("NESHAPs"), covering oil and gas production and transmission/storage equipment, respectively.[370] These section 112 standards built upon initial NESHAPs for the same sector that were finalized in 1999.[371] As they now stand, the requirements under the oil and gas

[367] For more discussion of this question, *see* Part III.D.2 below (OOOOa's "Significance" Finding for Oil and Gas Methane Emissions Is Neither Flawed Nor Required To Justify the Rule's Methane Standards.").
[368] *See* 74 Fed. Reg. at 66,497.
[369] *See generally Am. Elec. Power Co.*, 564 U.S. at 401.
[370] 77 Fed. Reg. at 49,501; 40 C.F.R. 63, Subpts. HH and HHH.
[371] 64 Fed. Reg. 32,610 (June 17, 1999).

NESHAPs establish HAP control requirements for glycol dehydrators, equipment leaks at gas processing plants, and storage vessels with flash emissions.[372]

The existence and scope of the oil and gas NESHAPs, however, in no way affect EPA's authority to issue the proposed OOOOc methane emission guidelines for the oil and gas sector.
Section 111(d) of the Clean Air Act specifies that, once it has issued new source standards for a source category under section 111(b), EPA must then issue emission guidelines covering

> any existing source for any air pollutant (i) for which air quality criteria have not been issued or which is not included on a list published under section [108(a)] of this title or emitted from a source category which is regulated under section [112] of this title but (ii) to which a standard of performance under this section would apply if such existing source were a new source.[373]

Historically, EPA has interpreted this language to mean that in issuing section 111(d) emission guidelines, the agency must address any pollutant for a given source category that was regulated as to new sources under section 111(b) standards *except* for pollutants regulated under section 108(a)'s national ambient air quality standards (i.e., criteria pollutants) *or* pollutants regulated under section 112's hazardous air pollutants program.[374] As EPA explained at length in the preamble to its final carbon dioxide emission guidelines for existing fossil fuel-fired electric generating units (commonly known as "the Clean Power Plan"), this interpretation accords with text, history, and structure of section 111(d), preserving the provision's long-standing "gap-filling" role to ensure that pollutants that were neither criteria pollutants nor air toxins would still be subject to regulation from existing sources.[375] It would also give legal effect to both of the two separate provisions amending (through different language) section 111(d) that were enacted into law through the 1990 Clean Air Act Amendments.[376]

Opponents of the Clean Power Plan, however, saw things differently. In litigation before the D.C. Circuit, they argued that in the 1990 Amendments, Congress intentionally meant to effectuate a change in the scope of section 111(d) such that EPA was now prohibited from issuing existing

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[372] 40 C.F.R. §§ 63.765-66, 63.769, 63.1275. Furthermore, the oil and gas NESHAPs expressly exclude from coverage storage vessels and equipment leaks at gas processing plants that are already subject to VOC standards under the OOOO rule. *See* 40 C.F.R. §§ 63.766(d), 63.769(b). Notably, many of the Joint Environmental Commenters have strongly urged EPA to strengthen and extend the coverage of the oil and gas NESHAPs, and a number of them submitted a petition for reconsideration to that effect on October 15, 2012. *See* Earthjustice, et al., Petition for Reconsideration of Oil and Natural Gas Sector: National Emission Standards for Hazardous Air Pollutants Reviews; Final Rule (Oct. 15, 2012). While EPA granted the petition in part, its process for reconsideration remains ongoing nine years later, and a group of environmental organizations—including one of the undersigned signatories—recently submitted a notice of intent letter to bring a citizen suit over EPA's unreasonable delay in completing the reconsideration process. *See* Adam Kron, Earthjustice, Notice of Intent to Bring Citizen Suit Concerning Clean Air Act Deadline and Unreasonable Delay of Action to Complete Reconsideration of the 2012 National Emission Standards for Hazardous Air Pollutants ("NESHAP"): Oil and Natural Gas Production and Natural Gas Transmission and Storage, 40 C.F.R. Part 63 Subparts HH, HHH (Dec. 9, 2021).
[373] 42 U.S.C. § 7411(d)(1).
[374] *See, e.g.*, 80 Fed. Reg. 64,662, 64,710 (Oct. 23, 2015).
[375] *Id.* at 64,710-15 (Oct. 23, 2015).
[376] *Id.* at 64,715.

source emission guidelines for *any* pollutant—including non-HAPs such as greenhouse gases—if the source category in question was already subject to HAP regulations under section 112. Although the D.C. Circuit ultimately dismissed the Clean Power Plan litigation as moot without deciding any issues in the case, it had occasion to consider the same legal question once again in litigation over EPA's "Affordable Clean Energy" rule, which was issued in 2019 as a replacement for the Clean Power Plan. In that litigation, the court rejected the argument that section 111(d) prohibited EPA from regulating *any* emissions from a source category already subject to section 112 NESHAPs.[377] Rather, the Court affirmed EPA's historical view: that the text, history, and structure of the Clean Air Act—and the 1990 Amendments—make clear that section 111(d) only prohibits EPA from regulatings in its existing source guidelines *hazardous air pollutants* from a source category already regulated under section 112, not from regulating *any air pollutant at all* emitted by a section 112-regulated category.[378]

As we discuss in detail in the following section of these comments, in the months that followed the D.C. Circuit's decision, Congress enacted and President Biden signed a Congressional Review Act resolution nullifying the 2020 Methane Policy Rule. In doing so, Congress took pains to emphasize that the D.C. Circuit ruling was correct and that the so-called "section 112 exclusion" argument was and always had been incorrect. The House Report accompanying the resolution affirmed that "[t]his argument is fundamentally incompatible with the language, structure, and Congressional intent in creating and adopting these CAA provisions," and would serve to "destroy the conscientious design of the CAA and perversely transform section 111(d) from a gap-filling provision to a gap-creating provision."[379]

On October 31, 2021, the Supreme Court granted certiorari to review a number of key issues decided by the D.C. Circuit in *American Lung Association v. EPA*. However, the Court denied certiorari over the D.C. Circuit's decision on the correct interpretation of section 111(d)'s so-called "112 exclusion." *See West Virginia*, 142 S. Ct. at 420 ("Petition for a writ of certiorari in No. 20-1778 granted limited to Question 2 presented by the petition"—i.e., the question not concerning the section 112 exclusion). Thus, the D.C. Circuit's decision on this issue is and will remain governing law, and the oil and gas NESHAPs in no way limit EPA's authority to issue methane emission guidelines under section 111(d) for existing oil and gas sources.

### B. The Impact of the Methane CRA Resolution.

#### 1. *By Enacting the CRA, Congress Nullified the Effect of the 2020 Methane Policy Rule and Foreclosed the Possibility of a Substantially Similar Rule in the Future.*

As discussed above, the Methane Policy Rule implemented two major changes to EPA's OOOOa regulations: it removed transmission and storage equipment from the source category definition (and thus the section 111(b) methane and VOC standards that applied to those sources), and it

[377] *Am. Lung Ass'n v. EPA*, 985 F.3d 914, 987 (D.C. Cir.), *cert. granted sub nom. West Virginia v. EPA*, 142 S. Ct. 420 (2021).
[378] *Id.* at 977-88.
[379] H.R. Rep. No. 117-64, 12 (2021).

rescinded methane standards for the entire source category. The effect of the methane CRA resolution signed into law by President Biden on June 30, 2021 was to permanently reverse these two changes and to reinstate OOOOa's source category definition, its methane standards for production and processing equipment, and its methane and VOC standards for transmission and storage equipment.[380]

As a result of the CRA Resolution, the 2020 Policy Rule was "made of no force or effect" and must "be treated as though [it] had never taken effect."[381] Moreover, EPA is now prohibited from issuing "a new rule that is substantially the same as" the Policy Rule unless Congress passes new legislation permitting it.[382] Any attempt by EPA either to remove the transmission and storage sector from the oil and gas source category as regulated under section 111 or to rescind methane standards for this source category would directly violate a congressional dictate and would be "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law."[383]

#### 2. *EPA's Proposed Actions Reversing the Methane Policy Rule Would Be Proper Even In The Absence of the Methane CRA Resolution.*

Even if Congress had not enacted (and the President had not signed) the Methane CRA Resolution, EPA would still have been compelled to reverse the Methane Policy Rule and reinstate the OOOOa rule's standards and source category definition. This is because the Policy Rule was based on patently incorrect legal foundations and was plainly arbitrary and capricious, as Joint Environmental Commenters explained in detail in our comments submitted to EPA on the Policy Rule.[384] Below, we provide a brief summary of these reasons.

### C. Removing Transmission and Storage Equipment from the Source Category Definition was Arbitrary and Capricious.

In the Policy Rule, EPA took the position that the oil and gas source category as established in the 1979 list only extended to production and processing equipment.[385] To the extent that the OOOOa rule amended the source category definition to include transmission and storage equipment, EPA then believed that it had "exceed[ed] the reasonable boundaries of [its] authority to revise source categories."[386] According to EPA, upstream (i.e., production and processing) segments and the downstream (i.e., transmission and storage) segments were not "not sufficiently related" to be placed in the same source category.[387] This was because (the argument went) the chemical composition of gas is slightly different in the upstream and downstream segments, with marginally

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[380] *See also* EPA, Congressional Review Act Resolution to Disapprove EPA's 2020 Oil and Gas Policy Rule: Questions and Answers (June 30, 2021), https://www.epa.gov/system/files/documents/2021-07/qa_cra_for_2020_oil_and_gas_policy_rule.6.30.2021.pdf.
[381] 5 U.S.C. § 801(f).
[382] *Id.* § 801(b)(2).
[383] 42 U.S.C. § 7607(9)(a).
[384] Env. Def. Fund, et. al., *Comments on Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review*, Dkt. No. EPA-HQ-OAR-2017-0757-2134, at 18-43 (discussing exclusion of downstream sources from source category), 43-90 (discussing withdrawal of methane standards) (Nov. 25, 2019).
[385] 83 Fed. Reg. at 57,025.
[386] *Id.* at 57,029.
[387] *Id.* at 57,027.

different amounts of methane, VOC, and HAPs; because gas undergoes a greater physical change in the upstream segments than in the downstream segments; and because certain specified pieces of equipment appear upstream but not downstream.[388] As a result, the agency concluded that it was "*required* to treat [downstream sources] as a separate source category and determine that in and of itself it causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare," which the agency had not previously done.[389]

These arguments simply collapse when subjected to basic logic. First, EPA properly determined in the OOOOa rulemaking that the 1979 source category listing was broad enough to encompass transmission and storage equipment in addition to production and processing equipment.[390] Since the early days of the NSPS program, EPA has taken a capacious approach to source categories, "intend[ing] [them] to be broad enough in scope to include *all processes associated with the particular industry*."[391] In 1978, in the process of determining which source categories to prioritize in forthcoming section 111 rules, EPA established "a list of sources not yet listed or regulated under NSPS provisions."[392] This list included a single line item for the oil and gas industry, and markedly did *not* include items for distinct oil and gas segments (such as the transmission or storage segments) either on the lists of "major" and "minor" categories or on the list of categories "not evaluated."[393] This leaves little doubt that EPA intended the 1979 listing of the oil and gas source category as inclusive of *all* segments of the industry.

Likewise, EPA's 1985 standards for natural gas processing plant emissions support the argument that the 1979 listing was broadly designed. The 1979 listing referred specifically to "Crude Oil and Natural Gas Production," yet there can be no dispute that natural gas *processing* is a distinct segment of the industry from natural gas (and especially oil) *production*. While EPA endeavored to argue in the Policy Rule that the production and processing segments are somehow more closely related to one another than either are to the transmission and storage segments,[394] the agency made no such indication either at the time that it listed the source category in 1979 or at the time that it regulated gas processing plants in 1985. Nor could it have: the main function of the production segment is to extract hydrocarbons from the ground, whereas the sole function of processing is to remove impurities from recovered gas. These functions bear no more inherent similarity to one another than they do to the transmission and storage segments. In particular, there can be no serious claim that *oil* production (which was explicitly included in the 1979 source category title) is more closely related to *natural gas processing* (which was the first segment EPA actually regulated under section 111(b)) than *any* of the segments of the natural gas supply chain are to one another.

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[388] *Id.* at 57,028-29.
[389] *Id.* at 57,029 (emphasis added).
[390] *See* 81 Fed. Reg. at 35,832-33.
[391] 45 Fed. Reg. 76,427-28 (Nov. 18, 1980).
[392] EPA, *Priorities for New Source Performance Standards Under the Clean Air Act Amendments of 1977*, EPA-450/3-78-019, at 3 (April 1978).
[393] *Id.* at 9, A-2, Table A-1 (listing "Source Categories Not Evaluated"), A-3 to A-6, Table A-2 (list of "Minor Sources"). *See also* 44 Fed. Reg. at 49,223 (noting that "two groups of sources in addition to minor sources are not included on the promulgated list" and that the first group of those sources "are identified in the [1978 Priority List]," while the second are those source categories listed prior to the 1977 Amendments).
[394] *See* 85 Fed. Reg. at 57,028.

In OOOOa, EPA resolved any ambiguities about the scope of the 1979 listing by, in the alternative, amending the oil and gas source category to cover transmission and storage equipment along with production and processing equipment.[395] As EPA explained, "[o]perations at production, processing, transmission, and storage facilities are a sequence of functions that are interrelated and necessary for getting the recovered gas ready for distribution," such that "segments that follow others are faced with increases in throughput caused by growth in throughput of the segments preceding (i.e., feeding) them."[396] Likewise, EPA noted that equipment such as storage vessels, pneumatic pumps, and compressors appear throughout all segments of the supply chain.[397] These factors, EPA concluded, justified including upstream and downstream sources in a single oil and gas source category.[398]

This should have been the end of the matter. However, in the Policy Rule, EPA reversed course and asserted that alleged differences in the gas composition at upstream and downstream sources *prohibited* EPA from including them in a single source category. This decision was plainly arbitrary. The plain fact remains that methane predominates in the gases contained in, and emissions from, equipment in *all* segments of the industry. The composition of the raw gas that comes out of wells varies greatly from basin to basin, and is a mixture of methane and other pollutants, including VOCs. Raw gas is then piped to gas processing plants to remove most of the VOCs and other impurities before it is piped further downstream as commercial gas. When leaks or intentional releases occur upstream of the processing plant, they reflect the composition of raw gas, (i.e., they are composed mostly of methane, plus some VOCs and other impurities). They generally (but not always) contain more VOCs and other impurities than leaks and releases downstream of the processing plant. But the whole way, methane predominates–usually by at least 70-90%.

For the purposes of establishing, revising, or rescinding methane standards, the Policy Rule offered no explanation as to *why* the relatively minor differences in gas composition between the upstream and downstream segments militate against including those segments in a single source category. The common element across the sector is methane. Every molecule of methane that moves through pipelines and compressor stations in the downstream segment originated in the upstream segment. The fact that more *additional* pollutants (VOCs and hazardous air pollutants) are co-emitted with methane upstream has no rational bearing on whether to regulate methane emissions from downstream sources as part of the same source category. Indeed, as explained elsewhere in the Policy Rule, "methane and VOC emissions occur through the same emission points and processes, and the same currently available technologies and techniques minimize both pollutants from these emissions sources."[399] In other words, the methane-to-VOC ratio of the gas stream is entirely irrelevant to how source owners control pollution, and thus has no rational bearing on the scope of the oil and gas source category under section 111.

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[395] *See* 81 Fed. Reg. at 35,832-33.
[396] *Id.* at 35,832.
[397] *Id.*
[398] *Id.*
[399] 85 Fed. Reg. at 57,051.

Notably, EPA has previously established section 111 categories with dramatically greater variances in throughput composition than those seen across the oil and gas segments. As one example, EPA's category for steam generating units encompasses sources that burn wood, solid waste, natural gas, distillate oil, residual oil, coal, and coal-derived synthetic fuels, all of which emit different quantities of pollution.[400] Thus, the nitrogen oxide standards for these units vary by a factor of *up to eight* depending upon the type of fuel burned.[401] This dwarfs the comparatively tiny differences in the chemical composition of gas between the upstream and downstream segments in the oil and gas industry.

Another notable example is fossil fuel-fired electric generating units, which EPA treats as a source category for the purpose of GHG regulations and includes two sub-categories: fossil steam electric generating units ("EGUs") and stationary combustion turbines. Consider just the units that fall within the fossil steam EGU subcategory, which include gas-, coal-, and oil-fired steam EGUs. According to a comprehensive EPA data set, these units emit on average 1,414 lbs CO2/MWh, 2,217 lbs CO2/MWh, and 2,356 lbs CO2/MWh.[402] Thus, the highest-emitting units– (oil-fired EGUs) emit approximately 67% more CO2 than the lowest-emitting units (gas-fired EGUs). This is a vastly greater range of emissions than the relatively tiny differences in gas composition that occur in different segments of the oil and gas supply chain: EPA found that in 2018, the average nationwide proportion of methane in gas in the transmission segment was only *five percent more* than in the production segment.[403] This is even smaller than the differences in CO2 emitted by coal plants alone: as these data show, EGUs that burn lignite emit over eight percent more CO2 per megawatt-hour than those that burn bituminous coal.[404] EPA's argument in the Policy Rule that the differences in gas composition *mandate* separate source categories for upstream and downstream sources borders on nonsensical when considered in the context of other long-standing source categories.

In the Policy Rule, EPA also cited the fact that gas undergoes a more significant physical change in the upstream segments compared to the downstream segments to justify removing transmission and storage equipment from the regulated category.[405] Once again, EPA provided no explanation as to why this fact matters in any way to the goal, means, or practice of regulating air emissions from this industry. Simply put, there is no such explanation: to owners and operators of gas equipment attempting to reduce their emissions, it is irrelevant that recovered gas undergoes a greater change in the production and processing segments compared to the transmission and storage segments. Finally, EPA argued that dividing the source category was necessary because "there are equipment types and processes present in the oil and natural gas production and

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[400] *See* 40 C.F.R. § 60.42b-44.b (setting standards with reference to these fuels).
[401] *Id.* § 60.44b(a).
[402] These data derive from EPA, Clean Power Plan Data File: Goal Computation Appendix 1-5 (Aug. 2015), https://archive.epa.gov/epa/cleanpowerplan/clean-power-plan-final-rule-technical-documents.html. This file provides CO2 emission data for all electric generating units operating in the United States in 2012. The figures cited above reflect generation from all units above 25 MW that generated at least some electricity in that year.
[403] 85 Fed. Reg. at 57,028 (EPA's 2018 survey of the most recent data found that "[t]he nationwide composition for the production segment consisted of approximately 88-percent methane," in comparison to its earlier finding that gas in the transmission segment consisted of 93-percent methane).
[404] *See* EPA, *supra* n. 402. The coal-fired EGUs in this data set that burned bituminous coal emitted 2,150 lbs $CO_2$/MWh, while the coal-fired EGUs that burned lignite emitted 2,332 lbs $CO_2$/MWh.
[405] 85 Fed. Reg. at 57,028.

processing segments that are not present, or not common, at natural gas transmission and storage facilities."[406] Yet it is equally true that there is equipment that is present in the production segment but not the processing segment and vice-versa, yet it is universally accepted that these upstream sources are properly included in the same source category.

For these reasons, EPA acted arbitrarily in the Policy Rule by removing transmission and storage equipment from the oil and gas source category. Even in the absence of the Methane CRA Resolution, EPA would have been obligated to rectify the Policy Rule's flaws and revert to the source category definition that appeared in the OOOOa rule. Congress clearly agreed, explaining in the House Report accompanying the Methane CRA Resolution that in OOOOa, EPA had "correctly" judged that the interrelated nature of the upstream and downstream segments and the general similarity of equipment across the segments justified s single source category.[407]

### D. Withdrawing Methane Standards for the Oil and Gas Sector Was Arbitrary and Capricious.

#### 1. *OOOOa's Methane Standards Are Not Redundant.*

EPA's decision in the Policy Rule to remove methane standards for the revised source category and leave only VOC regulations in place was likewise arbitrary. Specifically, EPA asserted that in OOOOa, it had "erred in establishing the methane NSPS because those requirements are redundant with the NSPS for VOC, establish no additional health protections, and are, thus, unnecessary."[408] First, as Joint Environmental Commenters discussed in detail in their commenter letter to EPA on the Policy Rule, the agency has a statutory obligation to regulate methane from the oil and gas sector in light of the 2009 Endangerment Finding. Claims of "redundancy" cannot revoke this statutory duty.

More importantly, oil and gas methane standards are not remotely redundant with VOC standards. EPA has consistently maintained that because VOCs from the oil and gas sector are ozone precursors, its issuance of VOC standards for this source category under section 111(b) do not provide EPA with the necessary legal predicate for issuing section 111(d) existing source emission guidelines, but that methane standards under section 111(b) *do* provide that legal predicate.[409] This is enormously consequential, since new sources contribute only a small fraction of the industry's regulated equipment and its emissions. Without the legal predicate for existing source regulation, the Policy Rule would permit EPA to regulate only a small fraction of the industry, including some 60,000 wells constructed since 2015. By contrast, there are more than 800,000 existing wells that would be subject to section 111(d) emission guidelines for existing sources. Collectively, these existing sources emit 10 million tons of methane, 2.3 million tons of VOCs and nearly 90,000 tons of hazardous air pollutants each year.[410]

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[406] *Id.* at 57,029.
[407] H. Rep. No. 117–64 at 24.
[408] 85 Fed. Reg. at 57,030.
[409] *Id.* at 57,040.
[410] Decl. of Dr. Renee McVay, Hillary Hull, and Katherine Roberts, Doc. No 1861564, *Environmental Defense Fund, et al. v. Andrew Wheeler et al.,* No. 20-1359 (D.C Cir. Sept. 15, 2020), at A90 (Table 6); *see also Envtl. Def. Fund et al., supra* n. 384, at 49.

Despite the fact that the Policy Rule's rescission of methane standards would have *barred* EPA from regulating existing sources, which it otherwise would have been *required* to regulate, the agency dismissed this crucial fact as nothing more than "a legal consequence that results from the application of the CAA section 111 requirements" and thus insisted on maintaining the fiction that methane standards were "redundant."[411] When confronted with the fact that, by its own logic, the oil and gas VOC standards were no less redundant than methane standards and could be rescinded without affecting EPA's obligation to issue existing source guidelines for the sector, EPA demurred that VOC standards should remain on the books because they were in place first and that "the decision of which NSPS to retain should not turn on the impact on existing sources,"[412] once again ignoring the massive environmental consequences of its decision. As described in the House report accompanying the CRA resolution, "the [Policy] Rule's misinterpretation of section 111 was glaring and enormously consequential" for ignoring the impacts on existing source emissions,[413] and was thus arbitrary and capricious.

2. *OOOOa's "Significance" Finding for Oil and Gas Methane Emissions Is Neither Flawed Nor Required To Justify the Rule's Methane Standards.*

Alternatively, EPA argued in the Policy Rule that the agency had no authority to issue methane standards in OOOOa because it had not properly "determine[d] that methane emissions from the Crude Oil and Natural Gas Production source category cause or contribute significantly to GHG air pollution as a predicate for promulgating [such] standards."[414] Again, this determination was arbitrary and capricious; OOOOa's "significance" determination is beyond dispute. In that rulemaking, EPA found that along with the 2009 Endangerment Finding, the oil and gas sector's large quantity of methane emissions—both as an absolute matter and as a percentage of both domestic and international GHG totals—supported a determination that the sector's methane emissions contributed significantly to dangerous air pollution.[415] As the agency noted, those emissions constitute approximately 3.4 percent of domestic GHG emissions and 0.5 percent of global GHG emissions, exceeding the GHG emission totals of over 150 countries and the *combined* emissions of over 50 countries.[416] This qualifies as "significant" emissions under any conceivable framework. Furthermore, these figures reflect the use of an outdated 100-year global warming potential ("GWP") of 25 for methane, and are based on EPA's own estimates of domestic oil and gas methane emissions, which research indicates dramatically underrepresent the true quantity of methane emitted by this sector.[417] Calculations using a more appropriate 20-year global warming potential of 82—or even a more updated 100-year GWP of 30—would present an even stronger

[411] *Id.*
[412] *Id.* at 57,052.
[413] H. Rep. No. 117–64 at 26.
[414] 85 Fed. Reg. at 57,033.
[415] 81 Fed. Reg. at 35,837-40, 35,877.
[416] *Id.* at 35,840.
[417] *See* Alvarez et al., *Assessment of methane emissions from the U.S. oil and gas supply chain*, 361 Science 186 (July 13, 2018) (indicating that sector-wide methane emissions are approximately 60 percent higher than EPA's GHG Inventory reflects); Robertson, et al., *New Mexico Permian Basin Measured Well Pad Methane Emissions Are a Factor of 5–9 Times Higher Than U.S. EPA Estimates*, 54 Environ. Sci. Technol. 13926–13934 (Oct. 15, 2020).

case for a significance determination,[418] as would those based on emission figures that more accurately reflect the quantity of methane resulting from domestic oil and gas development.

In the Policy Rule, EPA reversed course, finding that OOOOa's "significance" determination reflected estimates of methane emissions from the upstream and downstream segments together, whereas the appropriate source category definition covered upstream sources only. But as discussed above, the decision to remove downstream equipment from the source category was itself arbitrary and capricious, and cannot be the basis for reversing the agency's 2016 "significance" finding. The Policy Rule also included the argument that OOOOa's significance finding was invalid because EPA had not established a specific threshold or criteria for determining significance before issuing the rule.[419] Yet EPA has *never* established an across-the-board threshold or criteria for "significance" in the entire 50-year history of section 111. Nor should it have: the statute simply does require any such thing, but rather permits EPA to make significant contribution determinations suited to the characteristics of different pollutants and source categories in individual rulemakings. It is for this reason that the D.C. Circuit rejected a similar claim that EPA must enunciate precise criteria before determining that an air pollutant endangers public health and welfare.[420] The same reasoning applies here.

Finally, the Policy Rule's "alternative" basis for removing methane standards was arbitrary because under section 111, EPA need only make a significance finding for the *source category's total emissions* at section 111(b)(1)(A)'s *listing* stage. To actually issue standards for an individual pollutant emitted by a listed source category, the agency need only articulate a rational basis. This had been EPA's long-standing interpretation of section 111 prior to the Policy Rule, and in OOOOa, the agency maintained that interpretation, making a "significance" finding for the oil and gas sectors methane emissions only as a contingency.[421]

The Policy Rule's argument that EPA must make an *additional* significance finding whenever it seeks to regulate a new pollutant from a listed source category is entirely atextual. Section 111(b)(1)(A) is unambiguous: EPA must determine that "*a category of sources* . . . causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health" when determining whether to " include [that] category of sources in [a] list" required under section 111. 42 U.S.C. § 741(b)(1)(A) (emphasis added). That is, EPA must make an SCF in order to *list a source category*, and not for any other reason; indeed, the term "causes, or contributes significantly to, air pollution" appears only in section 111(b)(1)(A)—which is focused solely on listings—and nowhere else in the provision.

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[418] *See* IPCC, Sixth Assessment Report, Climate Change 2021: The Physical Science Basis, 7-125 (Aug. 2021). Because the next two decades are the critical window for taking action to avoid the worst impacts of climate change, the 20-year GWP for methane is much more appropriate for policymaking considerations than the 100-year GWP.
[419] 85 Fed. Reg. at 57,039-40.
[420] *Coal. for Responsible Regulation, Inc. v. EPA*, 684 F.3d 102, 122-23 (D.C. Cir. 2012) ("EPA need not establish a minimum threshold of risk or harm before determining whether an air pollutant endangers;" "the inquiry necessarily entails a case-by-case, sliding-scale approach."); *see also New York v. EPA*, 964 F.3d 1214, 1217 (D.C. Cir. 2020) (rejecting the "convoluted and seemingly unworkable showing [EPA] demanded" before regulating).
[421] 81 Fed. Reg. at 35,877.

The Policy Rule's interpretation of section 111 as additional pollutant-specific SCFs in order for EPA to regulate new pollutants from a previously-listed source category thus contravenes the basic language of the statute. The House Report accompanying the CRA resolution asserts that [t]he plain language of section 111 does not support this interpretation. The EPA's statutory interpretation prior to the [Policy Rule] is correct, and would be reinstated by this resolution of disapproval. This action reaffirms that once a source category is listed, regulation of any pollutant is reasonable provided that the EPA has a rational basis for concluding that regulation is appropriate to address dangerous air pollution."[422] As discussed above, EPA properly found that the quantity of methane emissions from the oil and gas sector easily satisfies the test for "significance" in any event. Thus, even under the "significance" test adopted in the Policy Rule, EPA has authority to control these emissions under section 111.

For these reasons, even if Congress had not enacted, and the President had not signed, the Methane CRA resolution, EPA's Policy Rule would still have been arbitrary, capricious, and unlawful.

### 3. *No Reliance Interests Arose as a Result of the Methane Policy Rule.*

The Methane CRA resolution is dispositive: unless and until Congress passes new legislation permitting it, EPA may not reinstate the Policy Rule for any reason, nor may it issue any "new rule that is substantially the same as" the Policy Rule.[423] Thus, no party can legitimately claim that any feature of the Policy Rule can be maintained in any way. But to the extent that oil and gas operators argue that any supposed reliance interests they may have based on the Policy Rule would justify more lenient OOOOb and c rules than might otherwise be the case, EPA must reject those claims. The Policy Rule was finalized on September 14, 2020; prior to that date, OOOOa remained fully in effect, despite EPA's never-finalized proposals to suspend LDAR and other requirements. Less than two months later, Joe Biden was confirmed as the winner of the 2020 U.S. presidential election. Mr. Biden had made explicit in his campaign materials an intention to "[r]equire[e] aggressive methane pollution limits for new and existing oil and gas operations,"[424] and specifically criticized then-President Trump's efforts to roll back methane policies in the first presidential debate that occurred soon after the Policy Rule was finalized.[425]

On his first day in office, President Biden issued Executive Order 13,390, which required the heads of all government agencies to "immediately review" and "consider suspending, revising, or rescinding" all regulations issued under the previous administration that conflicted with the new administration's climate and environmental policies.[426] Of particular note, the Order directed EPA to consider "proposing new regulations to establish comprehensive standards of performance and

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[422] H. Rep. No. 117–64 at 28.
[423] 5 U.S.C. § 801(b)(2).
[424] *The Biden Plan for a Clean Energy Revolution and Environmental Justice*, https://joebiden.com/climate-plan/ (last visited Dec. 27, 2021).
[425] USA Today, Read the full transcript from the first presidential debate between Joe Biden and Donald Trump (Sept. 30, 2020), https://www.usatoday.com/story/news/politics/elections/2020/09/30/presidential-debate-read-full-transcript-first-debate/3587462001/ (1:18:02 BIDEN: "He wants to make sure that methane is not a problem. We could, you could now emit more methane without it being a problem. Methane.").
[426] Exec. Order. No. 13,990 §2(a).

emission guidelines for methane and volatile organic compound emissions from existing operations in the oil and gas sector, including the exploration and production, transmission, processing, and storage segments, by September 2021."[427] Twelve days later, EPA moved the D.C. Circuit to hold the litigation over the Policy Rule in abeyance, explaining that "[]in light of [the] Presidential directive, the 2020 [Policy] Rule is under close scrutiny by EPA, and the positions taken by the Agency in this litigation to date may not reflect their ultimate conclusions. EPA should be afforded the opportunity to fully review the 2020 Rule consistent with the Executive Order, the Clean Air Act, and the agency's inherent authority to reconsider past decisions."[428] The Court granted the agency's motion on February 12, 2021.[429]

Soon thereafter, Congress took action to nullify the Policy Rule through the Methane CRA Resolution. Senator Martin Heinrich introduced the Resolution as S.J. Res.14 on March 25, 2021,[430] and the Senate approved it on April 28.[431] The House approved the Resolution in turn on June 25,[432] and the President signed the legislation into law on June 30.[433] Meanwhile, EPA proceeded with public outreach prior to issuing the OOOOb and c proposals. On May 14, EPA opened a pre-rulemaking docket for public comments regarding oil and gas emission reduction efforts; from May 25 through 26, the agency conducted "training webinars for communities, Tribes and small businesses to provide an overview of the oil and natural gas industry and share information to help members of those groups effectively engage in the regulatory process." The agency further held broad-based public listening sessions on June 15 through 17 and held a virtual public workshop August 23 and 24, 2021, to hear perspectives on innovative technologies that could be used to detect methane emissions from the oil and natural gas industry. Finally, on November 2, Administrator Regan signed the OOOOb and c proposals, which were released in pre-publication form that day and published in the Federal Register on November 15.

This timeline leaves no doubt that any reliance interests that oil and gas operators may have developed based on the Policy Rule were entirely baseless. Apart from the brief interlude between the time that EPA finalized the Policy Rule and the new administration took office and issued Executive Order 13,390, oil and gas operators have either had to comply with OOOOa in its entirety or have been on clear notice not only that OOOOa would likely be reinstated, but that stronger emissions standards—including requirements for existing sources—would likely be established by EPA. Any reliance interests that oil and gas operators may have had on the deregulatory effects of the Policy Rule are thus misplaced, and should play no role in EPA's regulatory design of the OOOOb and c rules.

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[427] *Id.* § 2(c)(i).
[428] Motion To Hold Cases In Abeyance, Doc. No. 1883156, *State of California, et al. v. Andrew Wheeler, et al.*, No. 20-1357 (D.C. Cir. Feb. 1, 2021).
[429] Order, 1883156, Doc. No. 1885114, *State of California, et al. v. Andrew Wheeler, et al.*, No. 20-1357 (D.C Cir. Feb. 12, 2021) (holding Policy Rule lawsuit in abeyance);
[430] S.J.Res.14 - A joint resolution providing for congressional disapproval under chapter 8 of title 5, United States Code, of the rule submitted by the Environmental Protection Agency relating to "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review, https://www.congress.gov/bill/117th-congress/senate-joint-resolution/14 (last visited Dec. 27, 2021).
[431] *Id.*
[432] *Id.*
[433] *Id.*

## IV. Source-Specific Comments

In this section we provide comments on the source-specific standards that EPA has proposed and those where EPA has solicited comment for development of a standard through a supplemental proposal. Our overarching recommendations are:

- **Fugitive Emissions Monitoring**: EPA should require quarterly or more frequent optical gas imaging at all sites regardless of the site-level emission estimate, particularly if EPA retains its well-head only exemption. If EPA retains the tiered approach, it should exclude sites with failure-prone equipment from tiers subject to less frequent monitoring and should revise the potential to emit calculation to account for the well-documented existence of super-emitters. Covering smaller, leak-prone wells with frequent inspections is critical as our analysis here shows that EPA's currently proposed one time only inspections at these well sites could reduce the overall effectiveness of its Leak Detection and Repair (LDAR) program by as much as half. At compressor stations, monthly monitoring should be required. EPA should also finalize an alternative standard that allows for screening with advanced technologies in combination with less frequent ground-based monitoring as long as equivalent emission reductions can be achieved. That alternative framework should likewise provide a pathway for continuous monitoring. Finally, EPA should finalize a community monitoring program that allows EPA to accept and use emissions data collected by third-parties.

- **Storage Vessels**: EPA's proposal to include tank batteries as affected facilities is a welcome revision. We also support EPA's new definition of modification for these sources. In determining what tanks or tank batteries are subject to the standards, EPA should base any applicability threshold on the affected facility's actual uncontrolled emissions. To the extent EPA retains a potential to emit based on legally and practicably enforceable limits, we support using the factors stated by EPA. However, if using a potential to emit approach EPA should revise the applicability threshold downward as leading states like Colorado have done.

- **Pneumatic Controllers**: EPA should finalize its zero-emission controller standard as proposed, with the exception of the functional need exemption currently proposed for processing plants. If EPA includes an exemption, the exemption should require that operators pursue secondary control options to reduce emissions to the greatest extent possible and provide clear justification for the technology implemented.

- **Liquids Unloading**: EPA should finalize a standard of zero emissions for liquids unloading events and should consider affected facilities any site that undergoes liquids unloading. EPA should require rigorous documentation of all liquids unloading events, and should set forth clear best practices that must be followed in limited situations in which liquids unloading cannot be conducted with zero emissions.

- **Compressors**: EPA should reduce the rod packing replacement threshold for reciprocating compressors based on annual monitoring from 2 scfm to 0.5 scfm. EPA should consider standards to reduce emissions from compressor exhaust and from dry seal centrifugal compressors.

- **Pneumatic Pumps**: EPA should set a zero-emission standard for pumps across the source category. If it includes a functional need exemption, the exemption's design should mirror that of pneumatic controllers.

- **Leaks at Processing Plants**: We support EPA's proposal to require bimonthly monitoring for leaks from pumps, valves, and connectors, as well as EPA's proposal to eliminate the "in VOC service" distinction. EPA should extend monitoring requirements to equipment designated with no detectable emissions.

- **Associated Gas at Oil Wells:** EPA should adopt performance standards that would eliminate the wasteful and unnecessary practice of disposing of associated gas through routine flaring. Specifically, EPA should determine that the BSER for emissions from associated gas during production is to capture and sell, productively use or reinject the gas. With respect to completions, we urge EPA to set performance standards that would eliminate venting throughout the flowback process except in case of narrowly-defined emergency; and eliminate flaring except in case of emergency or if necessary for pressure test purposes.

- **Abandoned Wells**: EPA should take steps to prevent wells from being improperly abandoned and orphaned by requiring operators to develop and comply with closure plans. EPA should also work with states to identify wells at high risk of abandonment and develop solutions.

- **Pigging and Blowdowns**: EPA should include proposed performance standards and emission guidelines for pigging and blowdown activities on gathering pipelines in its supplemental proposal, and should consider proposing such standards for transmission pipelines as well. EPA should continue to coordinate with PHMSA to ensure comprehensive oversight of pipeline methane emissions across agencies.

EDF used the Methane Policy Analyzer (explained fully in Attachment H) to analyze the total predicted effects of the proposed rule (methodology and detailed results included in the appendix). We compared the emissions levels predicted with the proposed regulations to baseline emissions predicted with current regulations (NSPS OOOO and OOOOa). We project that the baseline emissions in 2026, accounting for the effects of NSPS OOOO and OOOOa and current state regulations, will be approximately 17.3 million metric tons of methane. We did not model the effects of the pneumatic controllers provision and instead relied upon EPA's estimates since EPA used different emission factors that we were not yet able to incorporate into our model. In 2026, we estimate that the proposed rules could achieve the following reductions:

| **Rule provisions** | **Reductions from baseline (metric tons methane)** |
|---|---|
| Fugitive emissions | 3,739,500* |
| Storage Vessels | 44,400 |
| Liquids unloading | 56,700 |
| Compressors | 659,100 |
| Pneumatic pumps | 137,000 |
| Associated gas from oil wells | 110,200 |
| Well completions | 61,800 |
| Pneumatic controllers | 1,919,200** |
| Total | 6,727,900 |

* This estimate is based on the proposed alternative advanced screening LDAR standard, it therefore includes reductions from sites below 3 tpy PTE. We estimate that the reductions associated with LDAR could be *significantly* lower if, as proposed for the OGI standard, EPA does not require site below 3 tpy to undergo regular inspections. It is difficult to estimate how many sites fall below 3 tpy and, further, to estimate actual emissions (versus calculated PTE) from those sites. *See* Part IV.A.2.c. If sites below 3 tpy are subject to only a one-time inspection under the OGI program, this estimated fugitive emission reductions could *be reduced by as much as half*.

**Estimates for pneumatic controllers taken from EPA's RIA

### A. Fugitive Emissions Monitoring

Fugitive emissions from leaks and equipment failures are the most significant source of methane emissions from the oil and gas sector, and readily available technologies exist to find and fix these leaks and malfunctions. Rigorous leak detection and repair (LDAR) standards are therefore an indispensable element of a comprehensive program to address methane emissions across the supply chain. Some smaller leaks may be difficult to prevent, but as EPA has recognized, "large emission events are often attributable to malfunctions or abnormal process conditions that should not be occurring at a well-operating, well-maintained, and well-controlled facility that has

implemented the various BSER measures identified in [EPA's] proposal."[434] Nonetheless, significant emission events occur frequently and repeatedly across the oil and gas supply chain from all types of facilities operated by large and small companies.[435]

EPA should seek to reduce fugitive emissions to the greatest extent possible—at least equivalent to the reductions EPA estimates that quarterly to monthly Optical Gas Imaging (OGI) would achieve—through a comprehensive and frequent monitoring and repair regime. Existing and widely available technologies and practices allow for cost-effective detection and measurement of leaks that can then be repaired, leading to significant emission reductions, cost savings from captured gas, and improved health outcomes for nearby residents.

We support EPA's two-track approach outlined in the proposal which would allow operators to choose between a traditional OGI program and an advanced alternative utilizing newer technologies in conjunction with less frequent OGI surveys. Both of these LDAR options have the potential to significantly reduce fugitive emissions—including smaller component-level leaks and large super-emitter events stemming from abnormal process conditions. EPA should, however, increase the coverage and frequency of the OGI program to achieve greater emission reductions, something that can be done cost-effectively at all facilities. EPA should also maintain or increase the proposed frequencies for the advanced alternative and allow for a broader array of technologies to qualify as long as equivalent emission reductions can be achieved.

EPA's current methodology for estimating overall emissions from the oil and gas sector as well as reductions achieved by various standards does not account for super-emitters—the large intermittent emission events that are frequently observed across the oil and gas sector. This creates various analytical problems that lead EPA to underestimate emission reductions and overestimate the cost-per-ton reduced by control measures. It also creates problems for evaluating the effectiveness of fugitive monitoring programs, some of which put greater emphasis on quickly detecting super-emitters than others. EPA's assumptions about the effectiveness of optical gas imaging (OGI) are derived through analysis where super-emitters are not accounted for. This does not mean that EPA's assumptions about the effectiveness of OGI are necessarily incorrect, but rather that the percentage of total emissions reduced may be different than EPA has assumed if a the larger baseline of emissions is considered. Advanced leak detection methods may be capable of achieving greater overall reductions than OGI, if deployed protectively, when super-emitters are accounted for because advanced methods more quickly find the largest emission events. Conversely, advanced methods may be less effective when super-emitters are not accounted for because they do not capture as many component-level leaks as OGI.

In Section 1, we discuss nearly a decade's worth of scientific evidence documenting the magnitude of fugitive methane emissions from the oil and gas sector, and in particular, the problem of super-emitters and the persistent underestimation of super-emitters in official estimates. In Section 2, we discuss the proposed OGI standards at well sites, tank batteries, and compressor stations, including

[434] 86 Fed. Reg. 63,177.
[435] *See* Permian Methane Analysis Project, Operator Emissions, https://data.permianmap.org/pages/operators (showing ten operators with the highest number of detected emissions with emission rates greater than 1000 kg/hrl).

affected facility definitions and repair requirements, cost and cost-effectiveness estimates, site-level emissions estimates, and finally our recommendations. In Section 3, we discuss the proposed alternative advanced-screening approach. And finally, in Section 4, we discuss the community and third-party monitoring proposal. Our top level recommendations are summarized below.

**Optical Gas Imaging:**

*Scope*. EPA should clarify the definition of "fugitive emissions component" by including a non-exhaustive list of both components and equipment containing components that are common sources of fugitive emissions, and likewise should include control devices and venting components. EPA should also clarify and broaden the definition of "major production and processing equipment."

*Costs*. EPA should evaluate costs in a manner that better accounts for the reality in which operators will contract with LDAR providers and spread costs across multiple sites, some with higher and lower baseline emissions. If EPA retains tiered OGI standards, it should evaluate costs consistently across monitoring tiers and tpy increments. As proposed, EPA's cost analysis tends to overstate costs (and understate cost-effectiveness), particularly at smaller sites because it analyzes those sites individually and at single-ton increments. EPA should also revisit its assumptions underlying the costs of OGI monitoring, which are far higher than most other estimates. EPA should lower its cost estimates for recordkeeping and database management costs, and in particular, revise aspects of that analysis that double count and overestimate costs.

*Site-Level Emissions*. EPA should revise the site-level emission calculation so operators more accurately estimate emissions by accounting for equipment failures and abnormal process conditions. To do this, EPA should: 1) use emission factors that account for malfunctions; 2) use uncontrolled emissions for tanks; and 3) ensure emissions from all potentially emitting onsite equipment—like flares—are accounted for in the calculation.

*Recommendations - Well Sites*. EPA should require at least quarterly monitoring at all sites, particularly if EPA retains its wellhead only exemption. EPA must extend regular monitoring requirements to smaller, leak-prone sites, which are disproportionately large emitters and are prone to equipment failures. If EPA retains its tiered monitoring structure, it should categorically exclude sites with failure-prone equipment (i.e., tanks, flares, separators, and bleeding pneumatics) from any category subject to less frequent monitoring. Similarly, at larger sites, where an emission event could be very consequential, EPA should require more frequent monitoring—monthly or six times per year.

*Recommendations - Compressor Stations*. EPA should require more frequent monitoring–monthly or six times per year–at compressor stations and prompt repairs. This can be done cost-effectively and is necessary to ensure large emission events are quickly stopped to reduce emissions and protect the health of nearby residents.

**Advanced Monitoring**:

We support EPA's proposal to offer an alternative standard that allows monitoring with advanced technologies in combination with regular but less frequent OGI inspections. EPA should consider an approach that allows for technologies with differing minimum detection limits and continuous monitoring systems to be used if equivalent emission reductions can be achieved. As part of this, EPA should only allow proven technologies and should establish protective requirements for determining the capability of those technologies to repeatedly achieve the targeted minimum detection thresholds. In addition to this approach, EPA should continue to incentivize innovation by allowing operators to submit new technologies and approaches that can achieve the performance defined by EPA–which must be able to reduce emissions at least as much as the OGI standards.

**Community Monitoring:**

EPA should finalize a framework allowing third-parties to detect and report emissions to EPA, after which, and in response to credible data, the operator would be required to fix the leak. EPA can set parameters to ensure reported data is accurate, ensure the program helps to empower communities to use different technologies and methods, and ensure technologies are used safely and properly. EPA should also make all reported emissions publicly available. This type of program will foster public trust and accountability, while increasing knowledge on leaks and helping to further reduce emissions.

1. *Fugitive Emissions Studies*

Fugitive emissions are generally not intended as part of normal operations and can be broadly classified as leaks and unintentional vents. Sources of fugitive emissions include valves, flanges, connectors, thief hatches, pump diaphragms, seals, and open-ended lines, and many others. Causes of these emissions include persistent issues, such as equipment malfunctions (e.g., stuck open separator dump valve), as well as intermittent, short duration events (e.g., uncontrolled flashing from condensate tanks).[436] Fugitive emissions can also result from devices that vent as part of normal operations, such as natural-gas driven pneumatic controllers, and control devices or equipment combusting natural gas, like flares, when those devices are not operating as intended. Fugitive emissions that result from abnormal operating conditions or equipment failures are often referred to as abnormal process emissions and may also result in very large emission events, often termed "super-emitters."

Super-emitters and abnormal process emissions are often not well-represented (and may not be represented at all) in official inventories because they can be intermittent and are easily missed when taking equipment- or component-level measurements.[437] Bottom-up methods that estimate emissions using component or equipment counts and emission factors fail to account for super-emitter events and result in artificially low overall emission estimates. These measurement

[436] Zavala-Araiza et al., *Toward a Function Definition of Methane Super-Emitters: Application to Natural Gas Production Sites*, 49 Env. Sci. Tech. 8167 (2015), https://pubs.acs.org/doi/pdf/10.1021/acs.est.5b00133
[437] *See* IEA, *Methane Tracker Database* (October 2021), https://www.iea.org/articles/methane-tracker-database (summary of inventory estimates).

techniques capture only a snapshot of time; therefore, they may not be representative of emissions over longer timescales and are likely to miss intermittent emissions. Aerial detection methods and other top-down measurement and quantification techniques have documented the significance of large emission events and their large contribution to total emissions. This well-documented "fat-tailed" emission distribution means that 5-10% of sites are often responsible for 50% or more of total emissions.

Over the last decade, research by EDF and others has quantified the significance of methane emissions caused by oil and gas production and the persistent underestimation of fugitive and abnormal process emissions.[438] A large body of measurement-based studies have consistently found higher oil and gas methane emissions than is estimated in EPA inventories.[439] Bottom-up approaches like the EPA inventory greatly underestimate emissions because they are based on assumptions that do not account for large events caused by malfunctions and other abnormal conditions.[440] Accounting for these emission events can increase inventory estimates by 60-70%, underscoring the importance of quickly detecting and fixing major leaks.[441]

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[438] EDF, Methane research series: 16 studies, https://www.edf.org/climate/methane-research-series-16-studies

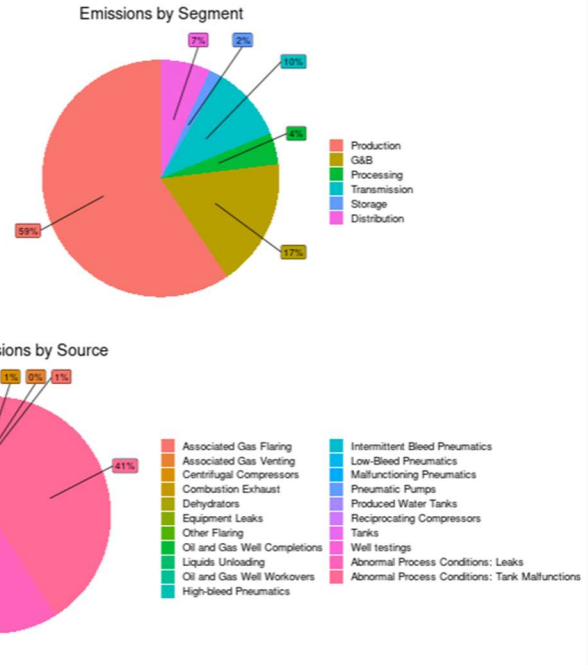
[439] Lyon et al., Constructing a spatially resolved methane emission inventory for the Barnett Shale region, 49 Env. Sci. Tech. 49, 8147–8157 (2015); Zavala-Araiza et al., Reconciling divergent estimates of oil and gas methane emissions, 112 Proc. Natl. Acad. Sci. 15597–15602 (2015); Zavala-Araiza et al.,. Super-emitters in natural gas infrastructure are caused by abnormal process conditions, 8 Nat. Comms. 14012—1421 (2017); Zimmerle et al., Methane emissions from the natural gas transmission and storage system in the United States, 49 Env. Sci. Tech. 9374–9383 (2015); Omara et al., Methane emissions from conventional and unconventional natural gas production sites in the Marcellus Shale region, 50 Env. Sci. Tech. 2099—2107 (2016); Peischl, J. et al., Quantifying atmospheric methane emissions from Haynesville, Fayetteville, and northeastern Marcellus shale gas production regions. 120 J. Geo. Res. Atmospheres, 2119–2139 (2015); Caulton et al., Importance of superemitter natural gas well pads in the Marcellus Shale. 53 Env. Sci. Tech. 4747—4754 (2019); Robertson, New Mexico Permian Basin measured well pad methane emissions are a factor of 5—9 times higher than U.S. EPA estimates, 54 Env. Sci. Tech. 13926—13934 (2020); Zhang et al., Quantifying methane emissions from the largest oil-producing basin in the United States from space, 6 Sci. Adv. 5120 (2020); Lyon et al., Concurrent variation in oil and gas methane emissions and oil price during the COVID-19 pandemic, 21 Atmos. Chem. Phys. 6605-6626 (2021).

[440] Rutherford et al., *Closing the methane gap in US oil and natural gas production emissions inventories*, 12 Nature Comms. 4715 (2021), https://www.nature.com/articles/s41467-021-25017-4#citeas

[441] Alvarez et al., *Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain*, 361 Science 186 (2018), https://science.sciencemag.org/content/361/6398/186

**Figure 2: Alvarez Synthesis Model Inventory Estimates[442]**

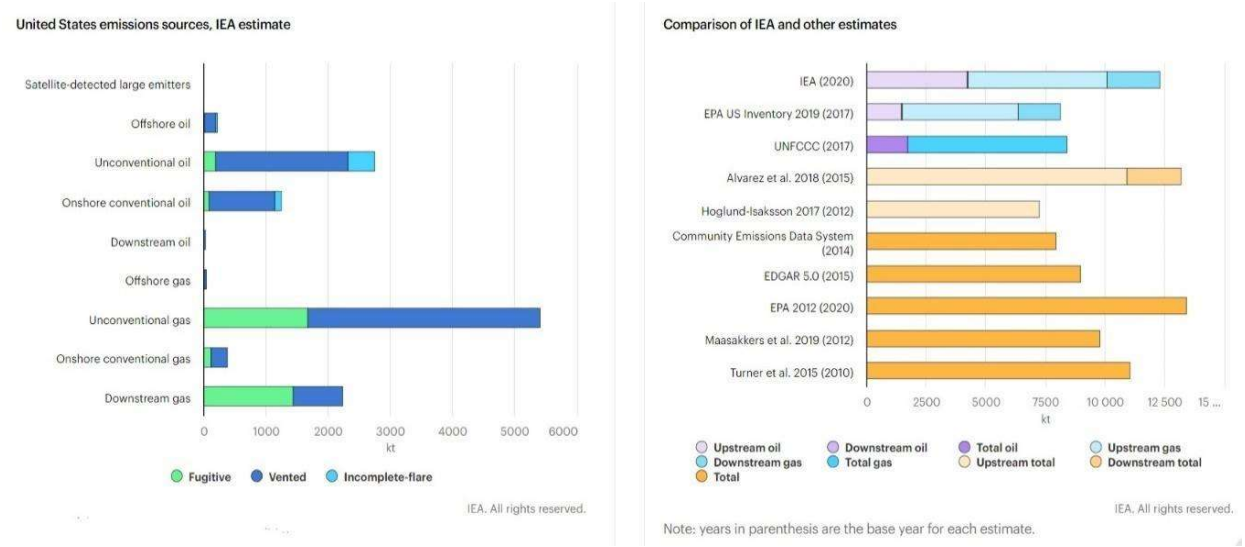
| | |
|---|---|
| Total Emissions (Metric tons methane): | 16,561,978 |
| Methane Leak Rate (based on gross production): | 2.4% |
| Methane Leak Rate (based on marketed production): | 2.7% |
| Total VOC Emissions (Metric tons): | 5,135,638 |




In 2012, EDF launched a series of research studies to quantify methane emissions from the U.S. oil and gas supply chain with diverse, measurement-based methodologies.[443] This collaborative work with over one hundred and forty experts from academia, industry, and government has resulted in more than forty peer-reviewed papers. In 2018, Alvarez et al., synthesized previous studies to estimate U.S. oil and gas supply chain methane emissions were 13 million metric tons in 2015, equivalent to 2.3% of natural gas production and about 70% higher than estimated by EPA's current Greenhouse Gas Inventory.[444] Numerous other studies have confirmed that bottom-up approaches like the EPA inventory greatly underestimate oil and gas methane emissions, largely capturing only component-level leaks and often missing the largest emission events.[445]

[442] For an explanation of the methodology used to create this inventory, *see* EDF, *2019 U.S. Oil & Gas Methane Emissions Estimate*, http://blogs.edf.org/energyexchange/files/2021/04/2019-EDF-CH4-Estimate.pdf
[443] *See* EDF, Methane research series: 16 studies, https://www.edf.org/climate/methane-research-series-16-studies
[444] Alvarez et al., *Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain*, 361 Science 186 (2018), https://science.sciencemag.org/content/361/6398/186.
[445] *See, e.g.*, Rutherford et al., *Closing the methane gap in US oil and natural gas production emissions inventories*, 12 Nature Comms. 4715 (2021), https://www.nature.com/articles/s41467-021-25017-4#citeas

**Figure 3: IEA Comparison of Emission Inventory Estimates**[446]




Recent research has found several common characteristics of oil and gas industry methane emissions. First, emissions occur across the value chain from well to end use, but are concentrated in the production and gathering segments, including well pads, tank batteries, and gathering compressor stations. EDF's emission inventory, derived from the Alvarez synthesis model (see Figure 2), estimates that production segment fugitive emissions represent nearly 50% of all oil and gas sector methane emissions. Second, all oil and gas facility types have a skewed distribution in which 5-10% of the highest emitting sites are responsible for about half of total emissions; however, the identity of these high-emitting sites can change with time and is difficult to predict. Third, low production or marginal wells tend to have lower absolute emissions than high production wells, but much higher loss rates as a percentage of gas production. And because roughly three quarters of all wells are marginal, they cumulatively contribute a substantial fraction of total emissions–up to 50% of production sector emissions according to a forthcoming study.[447] Fourth, emissions can almost always be mitigated once detected, sometimes with a simple repair to stop a leak, and other times by implementing operational or equipment changes that improve a site's efficiency.

EDF's Permian Methane Analysis Project (PermianMAP) uses several peer-reviewed measurement approaches to quantify oil and gas methane emissions in the Permian Basin, the nation's largest oil field, and then posts the emissions data on the public website PermianMAP.org to facilitate mitigation. This project and the associated studies have generated several important findings, which we briefly summarize here.

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[446] IEA, *Methane Tracker Database* (October 2021), https://www.iea.org/articles/methane-tracker-database (summary of inventory estimates).
[447] EDF, Marginal Well Factsheet (2021), https://www.edf.org/sites/default/files/documents/MarginalWellFactsheet2021_0.pdf; Attachment A (Omara AGU Slides 2021).

Zhang et al., a 2020 paper, estimates the Permian Basin loss rate is 3.7% of gas production, substantially higher than the national average.[448] In 2021, Lyon et al., found a similar loss rate of 3.3% in the core production area of the Delaware sub-basin in March 2020 using aircraft and tower-based measurements. The paper reports that the loss rate temporarily dropped to 1.9% in April 2020 when oil prices declined, but recovered to prior levels by summer 2020.[449] The authors hypothesize that the Permian Basin typically has a high loss rate because wells are developed faster than the pipelines and compressor stations needed to transport the gas to market. This leads to both high rates of associated gas flaring and abnormal emissions due to gathering systems with inadequate capacity. Therefore, the decline in well development during low oil prices temporarily relieved capacity issues and reduced emissions, bringing the leak rate closer to but still higher than EPA estimates. This study suggests that permanent reductions could be achieved by ensuring adequate gathering infrastructure before permitting new well development.[450]

Robertson et al., a 2020 paper, determined that New Mexico Permian well pad emissions were five to nine times higher than EPA estimates; complex pads including tanks or compressors had about twenty times higher average emissions than simple pads with only a wellhead.[451] Finally, Cusworth et al. in 2021 used an aerial remote sensing approach to quantify over 1,100 large methane sources in the Permian.[452] In support of previous research, the paper found that both the gathering sector and flares are large sources of emissions. They also assess the intermittency of large sources and determine that, on average, large emission sources are emitting 26% of the time.

In addition to quantifying methane emissions, EDF scientists have assessed flare performance in the Permian with a series of helicopter-based infrared camera surveys. Based on over one-thousand flare observations, approximately 5% of large flares are unlit and venting gas at any given time, and another 5% have visible slip of methane or other hydrocarbons–meaning the flare is only partially combusting the methane and the rest is escaping to the atmosphere. On-the-ground flare combustion efficiency is thus much worse than EPA has assumed and than regulatory standards require. Flares are consequently one of the largest sources of methane in the Permian Basin, and the latest surveys have found even worse performance among smaller, intermittent flares.[453]

Studies examining emissions from low-producing or marginal wells—those that produce an average of less than 15 BOE/day—find even greater leak rates. And because there are hundreds of thousands of these sites nationwide, the cumulative emissions are very problematic and may

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[448] Zhang et al., *Quantifying methane emissions from the largest oil-producing basin in the United States from space*, 6 Sci. Advances 17 (2020), https://advances.sciencemag.org/content/6/17/eaaz5120/tab-pdf

[449] Lyon et al., *Concurrent variation in oil and gas methane emissions and oil price during the COVID-19 pandemic*, 21 Atmos. Chem. Phys. 6605 (2021), https://acp.copernicus.org/articles/21/6605/2021/.

[450] See Part IV.XX (associated gas at oil wells)

[451] Robertson et al., *New Mexico Permian Basin Measured Well Pad Methane Emissions Are a Factor of 5–9 Times Higher Than U.S. EPA Estimates*, 54 Envtl. Sci. Tech. 13926 (2020), https://pubs.acs.org/doi/abs/10.1021/acs.est.0c02927.

[452] Cusworth et al., *Intermittency of Large Methane Emitters in the Permian Basin*, Envtl. Sci. Tech. Letters __ (2021), https://pubs.acs.org/doi/abs/10.1021/acs.estlett.1c00173

[453] *See* Attachment B (PermianMAP November 2021 Flyover Results).

represent more than half of total production-segment emissions.[454] In West Virginia, researchers found that wellhead methane emissions from marginal wells were 7.5 times larger than EPA's estimate, with an average methane loss rate of 8.8% of production leaked at the wellhead.[455] In the Appalachian Basin, researchers reported that marginal well sites in Pennsylvania and West Virginia have enormously varied methane loss rates, ranging anywhere from 0.35% to 91% of their production.[456] Based on a preliminary analysis of recent site-level measurements in the Permian, nearly half of observable production site methane emissions are from marginal well sites.[457] For the very low production category of 0-1 BOE/day wells, which contribute just 0.2% and 0.4% of national oil and gas production, respectively, research in the Appalachian Basin estimated that wellhead methane emissions account for 11% of the production-related methane emissions in the EPA's Greenhouse Gas Inventory.[458] The same research observed that many marginal wells emit as much or more gas than they reported producing—in a region where natural gas is the primary product operators are aiming to sell.

The scientific understanding of oil and gas methane emissions has expanded greatly over the last decade and can inform effective regulations for reducing emissions, especially fugitive monitoring programs. First, it shows that emissions can occur across the supply chain so regulations must have comprehensive coverage. Second, due to the skewed distribution of emission rates and the intermittency of some large emission events, the speed of detecting and stopping large emission sources is most critical for reducing total emissions—underscoring the importance of frequent monitoring and quick repair timelines. Third, because emissions are often episodic, after a screening approach finds a high emitting site, follow-up surveys must not only look for ongoing leaks, but include a root-cause analysis evaluating equipment and operational issues that could trigger high emission events. For example, an undersized tank control system could cause the tank hatch to intermittently pop open; closing the hatch will temporarily reduce emissions, but the problem will likely recur until the control system is fixed. And finally, smaller sites are disproportionate emitters of methane and should not be exempted from leak detection and repair or other regulatory requirements.

### 2. *Optical Gas Imaging Program*

In this section, we summarize, assess, and recommend changes to the proposed OOOOb and OOOOc's approach to a) the scope of fugitive monitoring (affected facilities), b) estimating costs, and c) calculating and estimating site-level emissions. Finally, we provide our policy recommendations for d) well sites and e) compressor stations.

#### a. Scope

[454] Attachment A (Omara AGU Slides 2021).
[455] Riddick et al., *Measuring methane emissions from abandoned and active oil and gas wells in West Virginia*, 651, Sci. of the Total Env. 1849 (2019), https://doi.org/10.1016/j.scitotenv.2018.10.082
[456] Omara et al., *Methane Emissions from Conventional and Unconventional Natural Gas Production Sites in the Marcellus Shale Basin*, 50 Env. Sci. Tech. 2099 (2016), https://pubs.acs.org/doi/10.1021/acs.est.5b05503
[457] Attachment B (PermianMAP November 2021 Flyover Results).
[458] Deighton et al., *Measurements show that marginal wells are a disproportionate source of methane relative to production*, 70 J. of the Air and Waste Mgmt. Assn. 1030 (2020), https://doi.org/10.1080/10962247.2020.1808115

As EPA has recognized that "[a] key factor in evaluating how to target fugitive emissions is clearly identifying the emissions of concern and the sources of those emissions."[459] EPA has also correctly recognized that "data shows that the universe of components with potential for fugitive emissions is broader than the illustrative list included in the 2016 NSPS OOOOa, and that the majority of the largest emissions events occur from a subset of components that may not have been clearly included in the definition."[460] We support EPA's proposal to expand the definition of fugitive emission components to more broadly encompass significant emissions sources and offer a few recommendations on how EPA can further strengthen this definition to achieve the aims articulated in the proposal.

EPA has proposed to amend the definition of "fugitive emissions component" to:

> any component that has the potential to emit fugitive emissions of methane and VOC at a well site or compressor station, including valves, connectors, PRDs, open-ended lines, flanges, all covers and closed vent systems, all thief hatches or other openings on a controlled storage vessel, compressors, instruments, meters, natural gas-driven pneumatic controllers or natural gas-driven pumps. However, natural gas discharged from natural gas-driven pneumatic controllers or natural gas-driven pumps are not considered fugitive emissions if the device is operating properly and in accordance with manufacturers specifications. Control devices, including flares, with emissions resulting from the device operating in a manner that is not in full compliance with any Federal rule, State rule, or permit, are also considered fugitive emissions components.

For reasons explained below, we recommend amending the definition as follows (additions underlined and deletions struck out):

> any component or <u>piece of equipment with components</u> that has the potential to emit fugitive emissions of methane and VOC at a well site <u>(including a centralized production facility or tank battery)</u> or compressor station, including <u>but not limited to all</u> valves, connectors, PRDs, open-ended lines, flanges, ~~all~~ covers and closed vent systems, ~~all~~ thief hatches ~~or~~ <u>and</u> other openings on ~~a controlled~~ <u>any</u> storage vessel, compressors, instruments, meters, natural gas-driven pneumatic controllers<u>,</u> ~~or~~ natural gas-driven pumps<u>, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals and diaphragms, separators, pressure vessels, dehydrators, heaters, flares, and other control devices</u>. ~~However, natural gas discharged from natural gas-driven pneumatic controllers or natural gas-driven pumps are not considered fugitive emissions if the device is operating properly and in accordance with manufacturers specifications. Control devices, including flares, with emissions resulting from~~ <u>Emissions detected during fugitive monitoring from natural gas-driven pneumatic controllers, natural-gas driven pneumatic pumps, flares, and other control devices are not considered fugitive emissions only if</u> the

[459] 86 Fed. Reg. 63,169
[460] *Id.*

> device is operating ~~in a manner that is not~~ in full compliance with ~~any~~ all applicable Federal rules, State rules, ~~or~~ and permits. ~~are also considered fugitive emissions components.~~

These recommended changes would reduce ambiguity about the scope of fugitive monitoring and what is considered a fugitive emission. First, we recommend including equipment types in the definition to avoid ambiguity that might cause certain sources of fugitive emissions to not be surveyed. For example, separators are not included in the proposed definition even though separator dump valves are a known significant source of large fugitive emission events. Under a proper reading of the proposed definition, separator dump valves should be included within the term "valve." But to avoid ambiguity, EPA should include certain equipment types like separators in the definition so it is clear that monitoring of separator dump valves and components on all other equipment is required.

Second, we recommend including "centralized production facility" and tank batteries as affected facilities where fugitive monitoring is required. Again, under a proper reading of the proposed definition, we think monitoring would be required at these sites. But including a specific reference or a cross-reference to the affected facility definition is important to avoid ambiguity and ensure fugitive monitoring occurs at tank batteries and other centralized production facilities, which are known large sources of fugitive emissions.

Third, EPA should include a non-exhaustive but more comprehensive list of fugitive emission components and equipment. Including a greater variety of components will help ensure they are not overlooked during fugitive monitoring and will reduce the potential for interpretations that might incorrectly narrow the scope of fugitive monitoring. In Colorado, for example, fugitive monitoring is required at "well production facilities."[461] Well production facility means:

> *all equipment* at a single stationary source directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline.[462]

Critically, EPA must avoid circularity in the definition that could be interpreted as not requiring fugitive monitoring for venting components and control devices if the operator believes the components are operating as intended. Fugitive monitoring must be required at venting components (like pneumatics) and control devices (like flares) *for the purpose of determining* if

[461] 5 Colo. Code Regs. § 1001-9, Pt. F, § N, p. 287 ("'Well production facilities' are also subject to leak detection and repair requirements and storage tank maintenance requirements. This definition is meant to include all of the emission points, as well as any other equipment and associated piping and components, owned, operated, or leased by the producer located at the same stationary source[.]")
[462] *Id.* at Pt. D, § I.B.30 (emphasis added).

the device is operating properly or not.[463] As currently written, an operator might believe that a flare or venting pneumatic is operating as intended and decide that it does not need to be surveyed for fugitive emissions. However, monitoring is the only way to ensure such a device is operating correctly and not malfunctioning and emitting at greater levels than intended. EPA should make clear that all gas-driven pneumatics, flares, and other control devices are subject to fugitive monitoring no matter whether they are operating correctly or not.[464] Of course, as encompassed in the recommended changes to the definition and the repair standards, if a surveyed venting component is emitting at permissible levels, those emissions would not be considered fugitive nor require repair. A clear regulatory definition explaining that fugitive emissions include impermissible vented emissions (i.e. those exceeding permissible levels or due to malfunctions) is also important for the structure and follow-up requirements of advanced monitoring.[465]

EPA has also proposed to retain the "wellhead only well site" exemption from fugitive monitoring.[466] Emissions, including large emission events, have been observed at wellhead only well sites[467] and this exemption is also problematic for reasons discussed in Part IV.J (abandoned wells). If EPA retains this exemption it should expand the definition of "major production and processing equipment" to ensure no equipment with potentially significant emissions is located at a site excluded from regular monitoring as a wellhead-only well site. Under OOOOa, a wellhead only well site is "a well site that contains one or more wellheads and no major production and processing equipment."[468] Major production and processing equipment means "reciprocating or centrifugal compressors, glycol dehydrators, heater/treaters, separators, and storage vessels collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water . . . ."[469] This definition does not include certain pieces of failure-prone equipment that could cause large emission events, like natural-gas driven pneumatic controllers and pumps, gas-driven pumpjack engines, and flares.[470]

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[463] *See, e.g.*, Cal. Code Regs. Tit. 17, § 95667, https://ww2.arb.ca.gov/sites/default/files/2020-03/2017%20Final%20Reg%20Orders%20GHG%20Emission%20Standards.pdf (requiring leak monitoring at natural gas driven pneumatic controllers and pumps).

[464] According to the International Energy Agency, flare efficiency and methane slip is "an area often overlooked by regulators." IEA analysis shows "in 2020, flares leaked on average around 8% of the natural gas and natural gas liquids that should have been combusted – more than double previous estimates. Incomplete combustion from flares accounted for about 10% of total oil and gas methane emissions, 95% of which was avoidable." The best way to prevent emissions from flares is eliminating flaring entirely, as discussed in Part IV.I (flaring). IEA, *Curtailing Methane Emissions from Fossil Fuel Operations: Pathways to a 75% Cut by 2030* (October 2021), https://www.iea.org/reports/curtailing-methane-emissions-from-fossil-fuel-operations

[465] *See* Part IV.A.3 (advanced monitoring); *see also* Fox et al., *A review of close-range and screening technologies for mitigating fugitive methane emissions in upstream oil and gas*, 14 Env. Res. Lett. 053002 (2019), https://iopscience.iop.org/article/10.1088/1748-9326/ab0cc3/pdf (discussing regulatory equivalence issues stemming from advanced methods' inability to distinguish between fugitive and vented emissions).

[466] EPA estimates that under its current proposal, only 280,000 well sites would be subject to regular leak detection and repair standards in 2026, out of a projected 590,000 total sites nationwide, indicating that approximately 47% of sites would be exempted when both the NSPS and EG go into effect. RIA Table 2-5; Figure 2-1.

[467] Attachment B (PermianMAP November 2021 Flyover Results).

[468] 40 CFR § 60.5430a

[469] 40 CFR § 60.5430a

[470] *See* Part IV.A.2 below for a full summary of scientific evidence on failure-prone equipment types.

We recommend EPA expand this definition so that no site with equipment that has potential for significant emissions is exempt as a wellhead only well site. Flares can be located at or near wellhead-only sites and must be clearly encompassed in the definition of major production or processing equipment.[471] EPA should also make clear that the proximity of the major production and processing equipment to the wellhead is not relevant for determining whether a site qualifies for the exemption. EPA should clarify that major production or processing equipment is at the site if it is associated with the site—*i.e.* if gas is routed from the wellhead to a nearby flare, that flare is part of the site (unless already part of another affected facility, like a centralized production facility). Otherwise, the regulations will create incentives to simply locate this equipment farther away from the site, which does nothing to reduce the potential for fugitive emissions. We support EPA's proposal to include a definition of "centralized production facility," which would be subject to fugitive monitoring requirements, and believe this may help eliminate incentives to strategically place equipment to avoid fugitive monitoring requirements.

If EPA retains the wellhead-only well site exemption, it should narrow it to apply only to single wellhead sites. Well sites that contain more than one wellhead must not be exempt, since there is no limit to the number of components (and therefore sources of fugitive emissions) that could exist at such sites, even if no associated equipment is present. Even without the addition of associated equipment, a well site with multiple single wellheads could be a significant source of emissions, in particular if there is a very large leak coming from one of the wellheads.[472]

b. Costs

Measures to reduce oil and gas sector methane emissions—including fugitive monitoring—are generally very low cost, and in many cases may lead to cost savings from captured gas. For this reason, a number of recent reports have identified oil and gas methane mitigation as a crucial near-term opportunity to limit climate warming that can be accomplished at low cost with available technologies and practices, making it the low-hanging fruit of climate action. For fugitive monitoring specifically, costs are extremely low, particularly in comparison to control techniques required in other sectors.[473] Here, we summarize fugitive monitoring costs and cost-effectiveness, assess EPA's approach to estimating costs, and provide recommendations for improvements. Advanced monitoring costs are discussed separately in Section 3 below.

The International Energy Agency (IEA) recently found that "more than 70% of [global oil and gas methane] emissions can be abated with existing technologies" and "the cost of mitigation is often

[471] *See* Attachment B (PermianMAP November 2021 Flyover Results) (finding that low-producing sites had a higher rate of flare malfunctions (31.3%) when compared to higher production sites (9.4%), and that malfunctioning flares at low-producing sites are often completely unlit and venting methane)
[472] Zavala-Araiza (2015), at 8176-8174; Attachment B (PermianMAP November 2021 Flyover Results).
[473] 86 Fed. Reg. 63,157 (EPA estimated that total capital costs due to compliance with the proposal would only represent a 0.3% increase for the sector. EPA regulations for EGUs increasing capital expenditures by 15.8% have been upheld as reasonable by the D.C. Circuit. This underscores how minimal any compliance costs are for an industry that spends hundreds of billions annually.)

lower than the market value of the gas that is captured."[474] The IEA estimates that "almost 45% of oil and gas methane emissions can be avoided with measures that would come at no net cost," and identifies leak detection and repair standards as one of the most important measures.[475] The IEA's analysis assumes quarterly monitoring occurs at all sites, but it also finds that "new and emerging technologies—including continuous monitoring sensors, aircraft, drones and satellites—can significantly reduce the cost of detecting fugitive sources when combined with on-site surveys."[476]

The United Nations Environment Program (UNEP) has similarly found that 60–80% of total oil and gas methane emissions can be cut at low cost and that the sector has "the greatest potential for negative cost abatement" because "captured methane adds to revenue instead of being released to the atmosphere."[477] A recent UNEP report examines analyses of per-ton abatement costs in the oil and gas sector and finds averages "around US $1,000 per tonne of methane in the Harmsen analyses, near zero in the IEA analysis, and having a net negative cost of roughly US $700 per tonne methane in the IIASA analysis."[478] Even the highest of these figures–$1,000 per ton–is less than half of the cost reported by EPA for the vast majority of the industry.[479] The report further points out that "[IEA] analysis shows that the category with the largest mitigation potential, upstream leak detection and repair (LDAR), is also the cheapest."[480]

Leak detection and repair using optical gas imaging (OGI) cameras is 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.[481] Studies have indicated that repair programs are highly effective—some finding that more than 90% of leaks remained fixed a year later.[482] However, the same study 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 the need for "frequent, effective, and low-cost LDAR surveys to target new leaks" and a "more definitive classification of leaks and vents."[483]

EPA's methodology for calculating costs of the OGI program generally overestimates costs, thereby underestimating cost-effectiveness. When coupled with the failure to account for large

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[474] IEA, *Curtailing Methane Emissions from Fossil Fuel Operations: Pathways to a 75% cut by 2030* (October 2021), https://www.iea.org/reports/curtailing-methane-emissions-from-fossil-fuel-operations
[475] *Id.*
[476] *Id.* at 25
[477] UNEP, Global Methane Assessment 96 (May 2021), https://www.unep.org/resources/report/global-methane-assessment-benefits-and-costs-mitigating-methane-emissions [hereinafter "UNEP Global Methane"].
[478] *Id.* at 96
[479] *Id.*
[480] *Id.* at 102
[481] 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/; Ravikumar et al., *Repeated leak detection and repair surveys reduce methane emissions over scale of years*, 15 Env. Research Letters 034029 (2020), https://iopscience.iop.org/article/10.1088/1748-9326/ab6ae1/pdf [hereinafter "Ravikumar 2020"].
[482] *See* Ravikumar 2020.
[483] *Id.*

emission events, the LDAR requirements appear much less cost-effective than would actually be true in most situations. In the proposal, EPA examined three elements of OGI monitoring costs: (1) the periodic monitoring for leaks; (2) the repair of leaks identified; and (3) the documentation of the activities.[484] EPA breaks these down into specific cost components that include: reading of the rule and instructions; development of a company-wide fugitives monitoring plan; recordkeeping database system set-up fee; cost for OGI monitoring (OGI camera survey); repair costs; costs to resurvey; annual recordkeeping database maintenance/license fee; additional recordkeeping/data management costs; and preparation of annual reports. EPA assumes a fugitive monitoring program will cover an average 22-site area and then distributes costs across sites. EPA uses these cost estimates and the percentage reductions achieved by various inspection frequencies to estimate cost-effectiveness.

EPA should revisit its repair cost assumptions, especially given the changes to the definition of "fugitive emission component" and the updated work practice standards for other sources to ensure they are not overestimates. Repairs of certain components and equipment that are required to be functioning properly under other work practice standards—like pneumatics, tank control systems, and flares—cannot be attributed to the costs of fugitive monitoring and repair. The operator is already required to ensure certain components and equipment function properly, so counting those costs in the costs of the LDAR program would be double counting.

Many of EPA's underlying cost assumptions in this proposal are retained from the 2020 OOOOa rulemaking. A notable exception is that EPA has nearly doubled its cost estimates of "annual recordkeeping database maintenance and license fee" and "additional recordkeeping/data management costs" since 2020. EPA updated these two categories of assumptions "to reflect the average costs provided directly by API associated with these activities, which [EPA] determined to be more representative of these costs." EPA did not explain why it believes API's cost figures are more representative, nor is there an adequate explanation of API's data or methodology in collecting that data. The updates to the recordkeeping cost assumptions provided by API increase total costs of semiannual monitoring by almost $700, which represents nearly all of the roughly $800 increase in total costs from 2020.

We conducted an in depth analysis of EPA's cost assumptions underlying the OGI cost estimates and cost-effectiveness analysis. We found that various cost components included double counting–meaning the same cost was accounted for in two or more cost components. EPA's 2021 analysis of OGI costs for well sites overestimates costs by double counting reporting, recordkeeping and data management, and other costs such as travel time. In addition, EPA relies on averages of API data that overestimate costs for recordkeeping and data management. We also reviewed compliance reports from EPA's WebFIRE database and found that the majority of reported survey times were far shorter than EPA's assumption. EPA assumes survey times (and travel times) that are higher than what is found in our initial review of annual compliance reports submitted to EPA. Below we explain these findings in detail.

[484] TSD at 12-16.

EPA's OGI cost analysis for well sites uses a labor cost for the OGI camera survey of $142/hour, based on contractor rates from Colorado's 2019 Regulatory Analysis for revisions to Regulation 7.[485] The $142/hour rate (2019$) is based on an annualized cost model that includes: capital costs for an FLIR camera, photoionization detector, and 4x4 truck; and annual costs for camera repair / maintenance, inspection staff, supervision, overhead, travel time, recordkeeping, reporting, and fringe benefits. The cost data are originally from a previous 2014 analysis by the state and are adjusted by 5.53% to account for inflation since 2014. Contractor rates are assumed to be 30% higher than an in-house rate. EPA uses this $142/hour rate to estimate annual well site level costs for OGI camera surveys.

***Reporting and recordkeeping costs are double counted.*** In addition to the OGI camera survey costs—which already include $7,500 per year in recordkeeping costs and $7,500 per year in reporting costs—EPA's analysis includes additional annual costs for repairs, repaired component re-surveys, and several additional annual recordkeeping and reporting costs. Specifically, these additional recordkeeping and reporting costs include: (1) annual recordkeeping database maintenance and license fees; (2) additional recordkeeping/data management costs; and (3) annual report costs. These three categories of annual reporting, recordkeeping and data management costs make up over 50% of the annual cost per well site for semi-annual OGI monitoring (and nearly 40% and 20% of the annual cost per well site for quarterly and monthly OGI monitoring, respectively). These costs are largely based on average costs provided to EPA by API in a May 22, 2019 memo.[486]

If EPA relies on API cost data for reporting, recordkeeping and data management then it should not also include recordkeeping and reporting costs elsewhere in its analysis. Specifically, EPA should remove the $15,000 per year recordkeeping and reporting costs that are factored into the $142/hour labor rate for OGI camera surveys. And EPA should adjust its annual report cost to account for the fact that the API cost data includes "preparation of the report for submittal to EPA." The three hours of additional labor EPA includes for preparing the annual report and storing/filing records likely double counts API's costs to review and submit the annual report to EPA.

Apart from the double counting, there are additional reasons to think that API's costs do not accurately reflect current costs associated with the OGI program. The costs provided by API were submitted in 2019, before EPA's 2020 amendments to OOOOa that streamlined the rule's recordkeeping and reporting requirements. In the 2020 rulemaking, EPA eliminated the requirement to keep various records, including those related to interim repairs and annual reports, and estimated the revisions would save $1,100 per site annually. EPA has not explained how the costs submitted by API in 2019 accurately reflect the costs that would be expected to occur under the revised and retained 2020 recordkeeping standards. EPA simply assumed in certain instances that the 2020 revisions would reduce costs by 25%.

***Travel time costs are double counted and may be overestimated.*** Travel time costs appear twice in EPA's OGI survey cost calculations. The 3.4 hours per survey used to calculate annual OGI

[485] *See* Table 14 of Economic Impact Analysis (Final) for Proposed Revisions to Colorado Air Quality Control Commission Regulation Number 7, November 5, 2019.
[486] EPA- EPA-HQ-OAR-2017-0483-2248_attachment_1 (May 22, 2019)

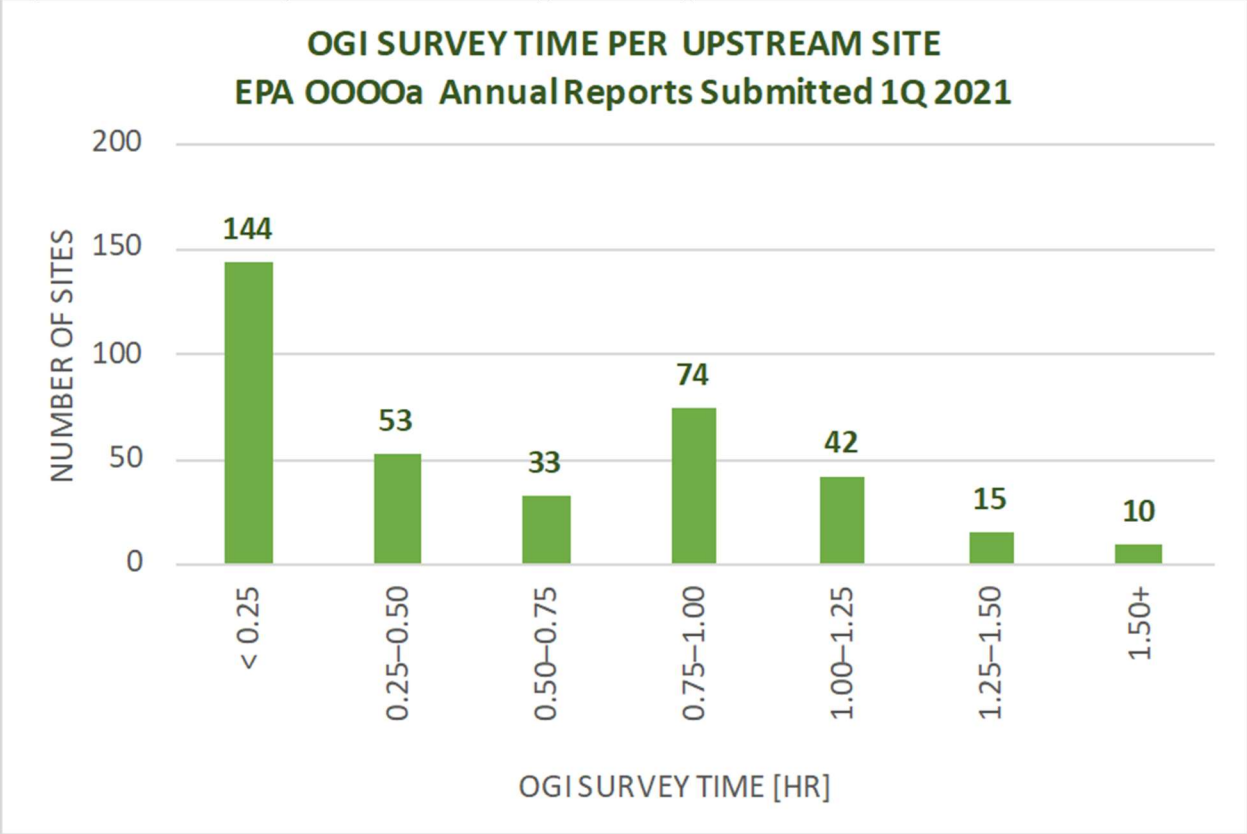
survey costs includes two hours of travel time (roundtrip) to the onsite survey, per well site. In addition, the labor cost for OGI camera surveys of $142/hour includes $11,250 per year in travel costs (note, this is in addition to the $22,000 capital cost for a 4x4 truck). If EPA accounts for travel in the total hours used to calculate OGI camera survey costs, per well site, then it should not also include travel time costs in the labor costs.

Additionally, the two hour per well site estimate for travel time is likely an overestimate, based on survey times in annual compliance reports submitted to EPA. In 2018, M.J. Bradley & Associates (MJB) conducted an analysis of OOOOa Annual Air Emission Reports and, among other things, concluded that the average time to conduct an LDAR survey is approximately 1.25–1.6 hours per well, *including travel time between sites*.[487] This analysis was based on reports submitted through July 31, 2018. Specifically, with regard to travel time, MJB reported an average time between ending a survey at one site and starting a survey at the next site ranged from less than five minutes to more than 2 hours, with an average of 30 minutes.

***Survey times are also likely overestimated.*** Based on a review of annual compliance reports in the EPA WebFIRE database, EPA's assumed average survey time of 1.5 hours per well site is likely an overestimate. We reviewed annual compliance reports submitted to EPA in early 2021. This timeframe captures the most recent reporting using an EPA template that includes survey time data; after March 31, 2021 annual compliance reports submitted to EPA do not include survey times. Due to the difficulty in identifying and downloading annual Air Emission Reports submitted by upstream sources, we were limited to a dataset of around 300 reports.[488] The figure below shows a distribution of reported LDAR survey times at well sites. For the approximately 300 upstream LDAR surveys with reported start- and end-time data reviewed, *over half took less than 30 minutes to complete and 82% took an hour or less*. Less than five percent of the LDAR surveys in the reports reviewed took more than 1.5 hours per well site. The average reported time to conduct the LDAR surveys was just over 30 minutes per well site across the data set.

[487] Attachment C (Memo from MJB to EDF 2018).
[488] EPA's WebFIRE database has very limited search filters (e.g., there is no filter for facility type) and only allows for bulk downloads of 10 reports at a time (also requiring the user to check and un-check report selections for every download).

**Figure 4: OGI Survey Times from Compliance Reports[489]**




One company submitted 71 reports in the first quarter of 2021 and reported that it completed each of its surveys in exactly one hour. This survey time covered upstream sources, including tank batteries and well pads with up to 30 wells, and is presumably a time period that adequately captures the time spent at these sites. One hour therefore likely overestimates many surveys for well pads with fewer wells. For this company, a one hour survey is reportedly sufficient for all of its first quarter 2021 surveys.

***Annual recordkeeping database maintenance and license fee costs are overestimated.*** EPA's OGI costs include a category for annual recordkeeping database maintenance and license fee costs based on the average cost provided to EPA by API.[490] In its memo to EPA, API reports data for two data systems: (1) in-house database and/or spreadsheets; and (2) customized commercial software systems. API reports, and EPA uses, the average of the cost per facility for 29 in-house and 308 customized commercial software systems. The fact that over 90% of the facilities in the dataset are using the customized commercial software system should be reflected in the average cost per facility in order to account for the fact that most facilities are using this type of system. EPA should use the weighted average of the data points across all 337 facilities, or $544/year per

[489] Attachment D (NSPS OOOOa Compliance Reports).
[490] EPA- EPA-HQ-OAR-2017-0483-2248_attachment_1 (May 22, 2019)

facility, instead of the $868/year per facility cost presented by API, which is the average of the two costs.[491]

In EPA's Background Technical Support Document for the Final Reconsideration of the NSPS OOOOa (August 2020), EPA reports, "information obtained from Krinkle (a Leak Detection and Repair (LDAR) database application) indicated there are annual fees of $70 for its LDAR application suite."[492] EPA took this cost estimate into account, along with "[a]dditional information received after the 2018 NSPS OOOOa proposal from API indicat[ing] that average ongoing annual costs to maintain the recordkeeping database, including IT support, Environmental Health and Safety (EHS) support, upgrades, etc. was $868 based on facilities surveyed by API."[493] EPA used an average ongoing annual fee of $470 for its model plant (i.e., the average of $70 and $868). Applying this same method but using API's weighted average of $544/year results in an even lower estimate for annual recordkeeping and data management costs, closer to $300/year.

***Initial costs to set up a data management program are overestimated.*** EPA's analysis includes first-year setup costs of $2,856, which includes developing a company-wide fugitives monitoring program. API submitted data to EPA for initial costs to set up a data management program of $2,839.[494] As with the other data submitted to EPA, API reports cost data for setting up two types of data systems: (1) in-house database and/or spreadsheets; and (2) customized commercial software systems. API reports, again, the average of the cost per facility for 29 in-house and 308 customized commercial software systems. The fact that over 90% of the facilities in the dataset are using the customized commercial software system should be reflected in the average setup cost per facility in order to account for the fact that most facilities are using this type of system. EPA should consider the weighted average of the data points across all 337 facilities, or $1,622 per facility, instead of the $2,839 per facility cost presented by API.[495] In fact, this cost is more in line with the $1,500 per facility setup cost assumed by CARB in its 2017 rulemaking for greenhouse gas emission standards for oil and gas facilities.[496]

Based on our review of EPA's cost of control analysis for OGI set forth in section 12.5.4 of the TSD, which is fully shown in Attachment E,[497] we recreated EPA's tables of control costs. Revisions to EPA's OGI cost estimates for well sites are summarized in the table below, with details included in the attached spreadsheet. These revisions include: (1) a revised labor rate for

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[491] Costs are calculated using API data, as follows:
$36,500/29 facilities = $1,259/facility for in-house systems
$147,000/308 facilities = $477/facility for customized commercial systems
Weighted average: ($1,259/facility * 29 facilities) + ($477/facility * 308 facilities) / (29 + 308) = $544/facility
[492] EPA-HQ-OAR-2017-0483-2290 at 33
[493] EPA-HQ-OAR-2017-0483-2290 at 33
[494] EPA- EPA-HQ-OAR-2017-0483-2248_attachment_1 (May 22, 2019)
[495] Costs are calculated using API data, as follows:
$125,000/29 facilities = $4,310/facility for in-house systems
$421,500/308 facilities = $1,369/facility for customized commercial systems
Weighted average: ($4,310/facility * 29 facilities) + ($1,369/facility * 308 facilities) / (29 + 308) = $1,622/facility
[496] CARB, Cost Estimates (2017), https://www.arb.ca.gov/regact/2016/oilandgas2016/oilandgas2016.htm; CARB, Attachment 2, (2016), https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2016/oilandgas2016/oilgasatt2.pdf
[497] Attachment E (EPA OGI Cost Analysis - well sites).

OGI camera surveys that removes the recordkeeping, reporting, and travel time costs; (2) revised annual recordkeeping database maintenance and license fee costs to reflect the weighted average API data; and (3) revised one-time initial setup costs to reflect CARB's setup cost estimate. These changes result in a roughly 20% decrease in annual costs per well site. Note, these revised costs likely still overestimate costs as annual reporting costs are included in both additional recordkeeping/data management costs and annual report costs, and the revised costs also likely overestimate both the travel time and survey time assumed for OGI camera surveys. If the time for survey and travel were revised from 3.4 hours to 1.25 hours the well site costs for monthly OGI monitoring (including all of the other revisions described above) would be $2,493, or roughly 40% less than EPA's estimates.

**Figure 5: Comparison of OGI Cost of Control & Revised Cost of Control[498]**

COMPARISON OF OGI COSTS FOR WELL SITES

| COST COMPONENT | COSTS FOR OGI PROGRAM | | | | | |
|---|---|---|---|---|---|---|
| | SEMI-ANNUAL | | QUARTERLY | | MONTHLY | |
| | EPA 2021 ANALYSIS | REVISED ANALYSIS* | EPA 2021 ANALYSIS | REVISED ANALYSIS* | EPA 2021 ANALYSIS | REVISED ANALYSIS* |
| **ONE-TIME INITIAL COSTS** | | | | | | |
| READ RULE AND INSTRUCTIONS (PER COMPANY) | $260 | $1,500 | $260 | $1,500 | $260 | $1,500 |
| DEVELOP COMPANY-WIDE FUGITIVES MONITORING PLAN (PER COMPANY) | $2,597 | | $2,597 | | $2,597 | |
| FIRST-YEAR TOTAL COST PER COMPANY | $2,856 | $1,500 | $2,856 | $1,500 | $2,856 | $1,500 |
| RECORDKEEPING DATABASE SYSTEM SETUP FEE (PER WELL SITE) | $897 | $897 | $897 | $897 | $897 | $897 |
| FIRST YEAR TOTAL "CAPITAL" COST PER WELL SITE (22 WELL SITES PER COMPANY) | $1,027 | $965 | $1,027 | $965 | $1,027 | $965 |
| **ONGOING ANNUAL COSTS (ALL PER WELL SITE)** | | | | | | |
| OGI CAMERA SURVEY | $966 | $755 | $1,931 | $1,510 | $5,794 | $4,529 |
| REPAIR COSTS – FUGITIVE COMPONENTS | $355 | $355 | $533 | $533 | $697 | $697 |
| REPAIRED COMPONENT RESURVEY | $22 | $22 | $32 | $32 | $38 | $38 |
| ANNUAL RECORDKEEPING DATABASE MAINTENANCE AND LICENSE FEE | $868 | $544 | $868 | $544 | $868 | $544 |
| ADDITIONAL RECORDKEEPING / DATA MANAGEMENT COSTS | $623 | $623 | $473 | $473 | $373 | $373 |
| ANNUAL REPORT | $195 | $195 | $195 | $195 | $195 | $195 |
| ANNUAL COST PER WELL SITE | $3,028 | $2,493 | $4,032 | $3,286 | $7,964 | $6,375 |
| ANNUAL COST PER WELL SITE WITH AMORTIZED CAPITAL COST | $3,200 | $2,655 | $4,204 | $3,448 | $8,136 | $6,537 |

*The revised analysis includes: (1) a revised labor rate for OGI camera surveys that removes the recordkeeping, reporting, and travel time costs; (2) revised Annual Recordkeeping Database Maintenance and License Fee costs to reflect the weighted average API data; and (3) revised one-time initial setup costs to reflect CARB's setup cost estimate. These changes result in a roughly 20% decrease in annual costs per well site (with amortized capital costs).

Using these revised cost assumptions, we recalculated the cost-effectiveness of semiannual, quarterly, and monthly OGI across the same tiers used by EPA.[499] Below are tables showing single

[498] Attachment E (EPA OGI Cost Analysis - well sites).
[499] *See* Attachment E (EPA OGI Cost Analysis - well sites).

and multipollutant cost-effectiveness of quarterly monitoring. Semiannual and monthly cost-effectiveness tables are included in Attachment E. As noted above, these are conservative estimates based on reduced costs per well site of 20%. If EPA revised travel time and time for the survey, as we believe it should based on our analysis of compliance reports, the cost per well site would be reduced by about 40%--resulting in even greater cost-effectiveness.

**SUMMARY OF THE COST OF CONTROL AT WELL SITES–QUARTERLY OGI MONITORING**

| SITE-LEVEL BASELINE METHANE EMISSIONS [TPY] | SITE-LEVEL BASELINE VOC EMISSIONS [TPY] | REVISED CAPITAL COST [$] | REVISED ANNUAL COST [$] | ANNUAL COST WITH SAVINGS [$/YR] | EMISSIONS REDUCTIONS [TPY] | | METHANE COST OF CONTROL [$/TON] | | VOC COST OF CONTROL [$/TON] | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | METHANE | VOC | WITHOUT SAVINGS | WITH SAVINGS | WITHOUT SAVINGS | WITH SAVINGS |
| 1.00 | 0.28 | $965 | $3,448 | $3,303 | 0.80 | 0.22 | $4,310 | $4,129 | $15,505 | $14,852 |
| 2.00 | 0.56 | $965 | $3,448 | $3,158 | 1.60 | 0.44 | $2,155 | $1,974 | $7,753 | $7,100 |
| 3.00 | 0.83 | $965 | $3,448 | $3,013 | 2.40 | 0.67 | $1,437 | $1,255 | $5,168 | $4,516 |
| 4.00 | 1.11 | $965 | $3,448 | $2,868 | 3.20 | 0.89 | $1,078 | $896 | $3,876 | $3,224 |
| 5.00 | 1.39 | $965 | $3,448 | $2,722 | 4.00 | 1.11 | $862 | $681 | $3,101 | $2,448 |
| 6.00 | 1.67 | $965 | $3,448 | $2,577 | 4.80 | 1.33 | $718 | $537 | $2,584 | $1,932 |
| 7.00 | 1.95 | $965 | $3,448 | $2,432 | 5.60 | 1.56 | $616 | $434 | $2,215 | $1,562 |
| 8.00 | 2.22 | $965 | $3,448 | $2,287 | 6.40 | 1.78 | $539 | $357 | $1,938 | $1,286 |
| 9.00 | 2.50 | $965 | $3,448 | $2,142 | 7.20 | 2.00 | $479 | $297 | $1,723 | $1,070 |
| 10.00 | 2.78 | $965 | $3,448 | $1,997 | 8.00 | 2.22 | $431 | $250 | $1,551 | $898 |
| 15.00 | 4.17 | $965 | $3,448 | $1,271 | 12.00 | 3.34 | $287 | $106 | $1,034 | $381 |
| 20.00 | 5.56 | $965 | $3,448 | $546 | 16.00 | 4.45 | $216 | $34 | $775 | $123 |
| 50.00 | 13.90 | $965 | $3,448 | -$3,808 | 40.00 | 11.12 | $86 | -$95 | $310 | -$342 |

*The revised cost analysis includes: (1) a revised labor rate for OGI camera surveys that removes the recordkeeping, reporting, and travel time costs; (2) revised Annual Recordkeeping Database Maintenance and License Fee costs to reflect the weighted average API data; and (3) revised one-time initial setup costs to reflect CARB's setup cost estimate. These changes result in a roughly 20% decrease in annual costs per well site (with amortized capital costs).

**SUMMARY OF METHANE AND VOC MULTIPOLLUTANT COST OF CONTROL AT WELL SITES–QUARTERLY OGI MONITORING**

| SITE-LEVEL BASELINE METHANE EMISSIONS [TPY] | SITE-LEVEL BASELINE VOC EMISSIONS [TPY] | REVISED CAPITAL COST [$] | REVISED ANNUAL COST [$] | ANNUAL COST WITH SAVINGS [$/YR] | EMISSIONS REDUCTIONS [TPY] | | MULTIPOLLUTANT METHANE COST OF CONTROL [$/TON] | | MULTIPOLLUTANT VOC COST OF CONTROL [$/TON] | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | METHANE | VOC | WITHOUT SAVINGS | WITH SAVINGS | WITHOUT SAVINGS | WITH SAVINGS |
| 1.00 | 0.28 | $965 | $3,448 | $3,303 | 0.80 | 0.22 | $2,155 | $2,064 | $7,753 | $7,426 |
| 2.00 | 0.56 | $965 | $3,448 | $3,158 | 1.60 | 0.44 | $1,078 | $987 | $3,876 | $3,550 |
| 3.00 | 0.83 | $965 | $3,448 | $3,013 | 2.40 | 0.67 | $718 | $628 | $2,584 | $2,258 |
| 4.00 | 1.11 | $965 | $3,448 | $2,868 | 3.20 | 0.89 | $539 | $448 | $1,938 | $1,612 |
| 5.00 | 1.39 | $965 | $3,448 | $2,722 | 4.00 | 1.11 | $431 | $340 | $1,551 | $1,224 |
| 6.00 | 1.67 | $965 | $3,448 | $2,577 | 4.80 | 1.33 | $359 | $268 | $1,292 | $966 |
| 7.00 | 1.95 | $965 | $3,448 | $2,432 | 5.60 | 1.56 | $308 | $217 | $1,108 | $781 |
| 8.00 | 2.22 | $965 | $3,448 | $2,287 | 6.40 | 1.78 | $269 | $179 | $969 | $643 |
| 9.00 | 2.50 | $965 | $3,448 | $2,142 | 7.20 | 2.00 | $239 | $149 | $861 | $535 |
| 10.00 | 2.78 | $965 | $3,448 | $1,997 | 8.00 | 2.22 | $216 | $125 | $775 | $449 |
| 15.00 | 4.17 | $965 | $3,448 | $1,271 | 12.00 | 3.34 | $144 | $53 | $517 | $191 |
| 20.00 | 5.56 | $965 | $3,448 | $546 | 16.00 | 4.45 | $108 | $17 | $388 | $61 |
| 50.00 | 13.90 | $965 | $3,448 | -$3,808 | 40.00 | 11.12 | $43 | -$48 | $155 | -$171 |

*The revised cost analysis includes: (1) a revised labor rate for OGI camera surveys that removes the recordkeeping, reporting, and travel time costs; (2) revised Annual Recordkeeping Database Maintenance and License Fee costs to reflect the weighted average API data; and (3) revised one-time initial setup costs to reflect CARB's setup cost estimate. These changes result in a roughly 20% decrease in annual costs per well site (with amortized capital costs).

***EPA should consistently apply its cost-effectiveness calculations.*** EPA analyzes cost-effectiveness of methane and VOC reductions at single-ton increments from 1 to 10 tpy, at five-ton increments from 10 to 20 tpy, and a thirty-ton increment between 20 and 50 tpy.[500] EPA does not explain why it evaluated cost at such a granular level for smaller sites but not at larger sites. With very small calculated baseline emissions such as 1 tpy, control measures appear less cost-effective. But even using this methodology—which places undue emphasis on cost-effectiveness at the smallest sites—EPA found quarterly monitoring at 2 and 3 tpy sites to be within its accepted cost-effectiveness range.[501]

EPA's method of dividing smaller sites into one-ton tiers and evaluating cost-effectiveness at such a granular level is inappropriate and skews the analysis to disfavor monitoring at lower tpy sites—despite no guarantee that these sites will remain below a given tpy threshold. If EPA retains this granularity at lower tpy sites, it should treat higher tpy sites the same and examine whether more frequent monitoring is justified at those sites, including by evaluating bi-monthly monitoring. If the majority of sites within a given tier (i.e. 1-3 tpy) can be monitored cost-effectively, then EPA should require monitoring at all the sites within that tier or otherwise adjust its parameters. It is arbitrary for EPA to exclude an entire tier of sites consisting of three tpy increments from regular monitoring because it found that monitoring at only one tpy increment within the tier would not be cost-effective.

We also emphasize that cost—which must only be "reasonable" under section 111—is only one factor EPA must examine when setting BSER, and EPA may not elevate costs over other statutory factors, such as the quantity of emission reductions achieved by a particular system. Nor does section 111 require EPA to use any particular approach to evaluate whether costs are reasonable. Thus, in this case EPA could evaluate LDAR costs by simply averaging cost-effectiveness across tpy tiers and setting a BSER (i.e., a particular monitoring frequency) that applied to all sites within a given range. It would be reasonable for EPA to assume that the average operator owns a diverse array of sites, spanning the different tpy tiers, and that the average 22-site area consists of sites spanning the tpy tiers. EPA could therefore assume that costs would be spread across those sites, allowing for higher costs at certain sites that would be offset by lower costs at others. Finally, EPA should not elevate its incremental cost-effectiveness analysis over more important considerations, such as emission reductions.

***Cost-effectiveness estimates from leading states are much lower than EPA's***. States, including Colorado, have found regular monitoring at smaller sites much more cost-effective than EPA. After the first year of Colorado's LDAR program, fugitive emissions were decreased by 75%, and

[500] TSD at 12-30.

[501] 86 Fed. Reg. 63189 ("[F]or sites with total baseline methane emissions of 2 tpy, we conclude that regular monitoring at semiannual or quarterly frequencies would be cost-effective."); *see also id*. at 63,155 ("EPA finds the cost-effectiveness values up to $1,800/ton of methane reduction to be reasonable").

the program was implemented smoothly. Colorado estimated the costs to be around $450 per inspection.[502] Table 2 below presents the costs of Colorado's 2019 requirements on a per-ton basis.

**Figure 6: 2019 Colorado LDAR Cost-Effectiveness Estimates** [503]

| Facility | LDAR Frequency | Uncontrolled VOC Emissions (tpy) | Nonattainment Area (NAA) Rest of State (ROS) | Total VOC Reduction (tpy) | VOC Control Cost ($/ton) | Total Methane Reduction (tpy) | Methane Control Cost ($/ton) |
|---|---|---|---|---|---|---|---|
| Storage Tank Battery at Well Site | Semiannual | 2-6 | NAA | 636.6 | $2,108 | 968.8 | $1,385 |
| | | 2-12 | ROS | 1,669 | $1,047 | 3,194.7 | $547 |
| | | | Total | 2,305.6 | $1,340 | 4,163.5 | $742 |
| Well Sites[504] | Quarterly | 12-50 | NAA | 7,280 | $1,019 | 10,920 | $679 |
| | | | ROS | 745.2 | $1,268 | 1,458 | $648 |
| | Monthly | >50 | NAA | 3,000.7 | $2,235 | 4,541.6 | $1,476 |
| | | | ROS | 517.7 | $2,752 | 1,002 | $1,422 |
| Compressor Stations | Semiannual | 0-12 | NAA | 78.3 | $2,008 | 173.7 | $905 |

In its most recent 2021 rulemaking, Colorado used hourly inspection rates of $105 for in-house and $137 for contractors, as well as an hourly repair cost of $82.06 to generate cost-effectiveness estimates.[505] EDF relied on these assumptions (with a slightly shorter repair timeline) and the EDF Methane Policy Analyzer to generate adjusted cost-effectiveness estimates based on the 2021 Colorado rulemaking.[506] EDF's estimates are shown in Figure 7. These estimates generally employ the Colorado Air Pollution Control Division's methodology but reflect EDF's alternative proposal as part of the Colorado rulemaking to require monthly screening at all well sites and all compressor

[502] Colorado Air Quality Control Commission, Regulatory Analysis of Regulations 3, 6 and 7, https://www.edf.org/sites/default/files/content/regulatoryanalysisattachment2013-01217.pdf (estimate based on the hourly cost ($134) times 3.4 hours=$456)

[503] Adapted from: Colorado Air Quality Control Commission, *Cost-Benefit Analysis* (Nov. 29, 2019), https://www.edf.org/sites/default/files/content/Attachment%20B%20-%20Regulatory%20Analysis%2C%20Colorado%20Dep%E2%80%99t%20of%20Public%20Health%20and%20the%20Environment%20%28Dec.%205%2C%202019%29.pdf

[504] Well site estimates are drawn from: Colorado Air Pollution Control Division, *Cost-Benefit Analysis for Proposed Revisions to AQCC Regulations No. 3 and 7*, pg. 28, Table 34 (Feb. 7, 2014), https://www.regulations.gov/document/EPA-HQ-OAR-2010-0505-7573

[505] Colorado Air Pollution Control Division, *Final Economic Impact Analysis for Regs. 7 and 22* (2021), https://drive.google.com/drive/folders/18e3kQ9heBASpIE5e6-bwzpFOzetxdA2G

[506] For a full explanation of the methodology, see EDF, Prehearing Statement, Exhibit 25 (2021) (EDF_PHS_EX-025), https://drive.google.com/drive/folders/1Wr6pbY7NoOXoDwIyXF3vXptF3OLG0gm-

stations in Colorado (as opposed to the tiered structure that was ultimately adopted). Under the alternative proposal operators would choose between monthly advanced screening (paired with annual or semiannual AIMM) or monthly AIMM).

**Figure 7: EDF-Adjusted Cost-Effectiveness Estimates Based on CO 2021 Methodology** [507]

| LDAR Frequency (all well sites and all compressor stations) | Methane Control Cost ($/ton) | CO2e Control Cost (GWP of 28) ($/ton) |
|---|---|---|
| Monthly AIMM | $994.12 | $35.50 |
| Monthly Aerial + Annual AIMM ($100/site) | $115.76 | $4.13 |
| Monthly Aerial + Annual AIMM ($200/site) | $335.92 | $12.00 |

The California Air Resource Board's (CARB) cost estimates are also lower than EPA's. In 2016, CARB estimated that quarterly monitoring cost $23-$75 per ton of CO2e reduced using 20- and 100-year GWP, with and without gas savings.[508] CARB used $60/hr for labor, based on the average of contractor data points it gathered ($55, $70, $62, $55, $50).[509] CARB also assumed $1,500 per facility to account for setup costs.[510]

***Publicly available cost estimates are much lower than EPA's.*** Most publicly available cost estimates of OGI surveys are around $500-600 per well site.[511] Data from oil and gas producing companies and methane mitigation companies consistently confirm the cost of LDAR surveys are

[507] EDF, Alternative Proposal, Economic Impact Analysis for Regs. 7 and 22 (2021), https://drive.google.com/drive/folders/1UY2aiAZ8HjsVx7QiFzlxCdZSAdiA4bhS
[508] CARB, Attachment 2 (2016), https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2016/oilandgas2016/oilgasatt2.pdf
[509] *Id.*
[510] *Id.*
[511] Kemp & Ravikumar, *New Technologies Can Cost Effectively Reduce Oil and Gas Methane Emissions, but Policies Will Require Careful Design to Establish Mitigation Equivalence*, 55 Env. Sci. Tech 9140 (2021) https://pubs.acs.org/doi/10.1021/acs.est.1c03071; EPA Methane Detection Technology Workshops (Presentations of Arvind Ravikumar and Erin Tullos), available at, https://www.regulations.gov/document/EPA-HQ-OAR-2021-0317-0181; Ravikumar & Lyon, *Impact of survey frequency on emissions mitigation at oil and gas sites*, Appendix D (December 2018), https://www.edf.org/sites/default/files/content/Appendix_D_Ravikumar_and_Lyon_Impact_of_Survey_Frequency_on_Emissions.pdf

even lower. One company, Jonah Energy, documented a 75% reduction in leak detection over five years in Wyoming.[512] Jonah Energy also found that total LDAR program costs decreased from $99 per inspection in the first year to $29 per inspection in the fifth year.[513] Further, in each year, the total value of the captured gas across Jonah Energy's operations offset LDAR survey costs by at least $10,000, including one year where the captured gas resulted in more than $90,000 net in savings.[514]

Texas-based Rebellion Photonics has stated that its own leak detections services cost $250 per site.[515] FLIR Systems reports that LDAR inspections conducted by third-party service providers may cost as little as $141 per site—far lower than EPA's estimate.[516] Yet another company, Target Emission Services, found, based on its own data, that LDAR monitoring costs for compressor stations are $1,220, inclusive of onsite monitoring, travel expenses, and reporting, per survey.[517]

c. Site-Level Emission Calculations

In this part, we discuss EPA's proposed approach for operators to estimate production site emissions for purposes of the OGI monitoring program. We support EPA moving away from the model plant approach and instead relying on site-specific baseline emission estimates to categorize sites. However, as proposed, the site-level estimates still fail to fully characterize site-level emissions because they do not account for super-emitter and abnormal process emissions. These categories of emissions are particularly prevalent and problematic in the production segment, representing more than 70% of total emissions.[518] To more accurately estimate site-level emissions, EPA should require operators to: 1) use emission factors that account for malfunctions; 2) use uncontrolled emissions for tanks; and 3) estimate emissions from all potentially emitting onsite equipment—like flares—in the calculation. Adopting these recommendations will help ensure sites fall into representative emission tiers and are subject to the appropriate frequency of monitoring.

We agree with EPA that its previous model plant approach for estimating well site fugitive emissions did not fully capture those emissions. This approach, which divided well sites into

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[512] Wyoming Public Media, WY Approves Strict Air Pollution Regs for Pinedale (2015), http://wyomingpublicmedia.org/post/wy-approves-strict-airpollution-regs-pinedale.
[513] EDF, Finding, fixing leaks is a cost-effective way to cut oil and gas methane emissions (2016),http://www.methanefacts.org/files/2016/05/LDAR-Fact-Sheet-FINAL.pdf (citing WCCA Spring Meeting, Jonah Energy Presentation, May 8, 2015 delivered by Paul Ulrich. It is unclear if this assumed one or two well sites per inspection.).
[514] The first year resulted in a net savings of $22,159, $10,955 in the second year, $90,577 in the third year, $41,256 in the fourth year, and $28,691 in the fifth year.
[515] Rebellion Photonics comments at the EPA public hearing on the proposed NSPS OOOOa rule in Dallas, TX on September 23, 2015, https://www.edf.org/sites/default/files/content/attachment_1_-_rebellion_epa_hearing_testimony.pdf
[516] FLIR Systems, (Apr. 22, 2016) https://www.regulations.gov/?elq=3ff5b8047ab24463aa9991e03f221745%26elqCampaignId=1306#!documentDetail;D=BLM-2016-0001-9035
[517] Terence Trefiak, Target Emission Services, NSPS OOOOa Monitoring Case Study (Mar. 7, 2018), Docket ID No. EPA-HQ-OAR-2017-0483-0031.
[518] Alvarez 2018.

production-based categories and then assigned average estimated component and equipment counts to derive emissions, did not capture *actual* well site component and equipment counts, particularly at more complex facilities.[519] It was also not representative of well site emissions because it relied on emission factors that do not account for large emission events and because it tended to underestimate average onsite equipment counts.[520] EPA has correctly recognized the flaws in this approach, as well as in those that assume leak rates are well correlated with production levels.[521]

However, EPA's proposed approach, based on potential to emit, also suffers from flaws that will cause underestimating of actual emissions – shortcomings that are especially problematic when operators rely on the calculation to determine the required frequency of inspections for a particular site. We recommend that EPA revise the site-level calculation methodology to account for super-emitters and equipment failures, rather than using the proposed potential to emit (PTE) calculation described below:

- For each natural gas-driven pneumatic pump, continuous bleed natural gas-driven pneumatic controller, and intermittent bleed natural gas-driven pneumatic controller located at the well site, the owner or operator would apply the population emission factors for all components found in Table W-1A of GHGRP subpart W.

- For each piece of major production and processing equipment and each wellhead located at the well site, the owner or operator would first apply the default average component counts for major equipment found in Table W-1B and Table W-1C of GHGRP subpart W, and then apply the component-type emission factors for the population of valves, connectors, open-ended lines, and PRVs found in Table 2-8 of the 1995 Emissions Protocol.

- Finally, the owner or operator would use the calculated potential methane emissions after applying control (if applicable) for each storage vessel tank battery located at the well site. The sum of the emissions estimated for all equipment at the site would be used as the baseline methane emissions for determining the applicable monitoring frequency.[522]

This approach is not an accurate representation of a site's true potential to emit and suffers from three main flaws. First, any approach to estimating emissions that relies solely on subpart W

[519] Attachment F (ICR analysis)
[520] *Id.*
[521] 86 Fed. Reg. 63187; *see also* Lin et al., *Declining methane emissions and steady, high leakage rates observed over multiple years in a western US oil/gas production basin*, 11 Sci. Reports 22291 (2021) ,https://www.nature.com/articles/s41598-021-01721-5 (finding a steady leak rate of 6-8% over six years in the Uinta Basin even as production declined and attributing high leak rate in part to the abundance of low producing wells in the basin).
[522] 86 Fed. Reg. 63171

emission factors fails to account for the problem of abnormal process emissions and equipment failures and will underestimate emissions from many (if not all) sites. An approach that fails to account for these emissions, documented through extensive scientific studies, does not accurately represent actual emissions from the oil and gas sector, nor what would be expected at a typical site. One result is that control techniques and standards appear less effective at reducing emissions and more costly per ton reduced throughout EPA's analysis than they would actually be. For example, under this calculation a site might determine that its PTE is 10 tpy and EPA's cost-effectiveness analysis would then show an 8 tpy reduction for quarterly monitoring.[523] In reality, that same site has much greater potential emissions, so quarterly monitoring for the same cost would actually be achieving much greater reductions and would be more cost-effective. Another result is that sites will fall into artificially low tpy tiers and be subject to less frequent monitoring than they would be if they calculated emissions accurately. This means that a site which EPA has determined should be subject to quarterly monitoring could end up only being required to conduct a one-time inspection. This problem is exemplified in Figure 8 below.

A second and related major problem with this approach is that it allows operators to estimate site-level emissions on the assumption that any control equipment will be 100% effective 100% of the time. Again, this does not reflect reality and ignores countless field observations of the repeated failure of control equipment that leads to large emission events, especially those associated with tanks.[524]

Third, this approach does not require operators to calculate potential emissions from all of the emitting equipment onsite, only a subset. Flares are an example—this commonly malfunctioning piece of equipment that can cause major emission events is totally left out of consideration in EPA's proposed site-level emission calculation. A representative site-level emission calculation cannot exclude potential emissions from *any* equipment located at the site.

If PTE is supposed to represent the theoretical *potential* to emit, then in most cases, a well site's PTE is equivalent to its entire methane production (i.e., natural gas production adjusted by methane content). For example, if there is a malfunction that causes 100% of the gas production to vent, such as a stuck separator dump valve, then the site's emissions are equivalent to its methane production. In rare cases, a site's emissions may even exceed production, such as an over-pressurized gathering system venting at an upstream tank. EPA's proposed calculation using subpart W methods and assuming controls are working does not, in fact, calculate PTE, but rather the possible *baseline* emissions of a site that is operating without any malfunctions whatsoever on a continuous basis. Numerous research studies have shown that this approach underestimates average emissions due to malfunctions.

EPA's proposed calculation is even less likely to accurately capture potential emissions when considering its application to smaller sites that may calculate less than 3 tpy, allowing those sites to avoid regular monitoring and repair. These sites, many of which are declining marginal or stripper wells, are even less likely than other sites to be operating correctly in the way the proposed

[523] TSD at 12-33, Table 12-12a.
[524] *See* Attachment B (PermianMAP November 2021 Flyover Results); *see also* Part IV.A.1.

PTE calculation assumes.[525] Most of these declining sites have never been subject to federal air pollution regulations, will have older and more-leak prone equipment and components, and are likely lowest on operators' priority lists for regular inspections and equipment upgrades.[526] All of these factors suggest that many sites calculating less than 3 tpy are among the most likely to emit above the level otherwise determined by EPA's calculation under the proposal.

EPA's tiered LDAR proposal is similar to Colorado's, but Colorado uses an uncontrolled tank emission calculation that is more representative of real site conditions.[527] This calculation still does not account for issues like unlit flares and stuck separator dump valves, but it is more representative of a site's actual potential emissions. Under the Colorado regulations:

> For well production facilities with storage tanks, the threshold determining inspection frequency is based on the uncontrolled actual VOC emissions from the highest emitting storage tank. For well production facilities without storage tanks, the threshold determining inspection frequency is based on "facility emissions." The [Colorado Air Quality Control] Commission has determined that "facility emissions" means the controlled actual VOC emissions from all permanent equipment, including fugitive emissions calculated using the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates.[528]

This approach still greatly underestimates actual site-level emissions because it does not account for most equipment failures and relies on outdated emission factors. However, it is directionally an improvement from EPA's proposed PTE calculation because it uses uncontrolled tank emissions, and tanks are the largest source of fugitive and abnormal process emissions by most estimates.

In the proposal, EPA suggests that the scope of its LDAR proposal is more protective than Colorado's. EPA specifically claims that the proposed quarterly monitoring at sites from 3 tpy to 8 tpy is more stringent than Colorado regulations.[529] However, EPA fails to account for the significant differences in actual coverage that result from using a different site-level emission calculation. Furthermore, Colorado recently updated its regulations, increasing monitoring frequencies and requiring regular monitoring at all tiers.[530]

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[525] *See* Attachment B (PermianMAP November 2021 Flyover Results).
[526] Wendt et al., Methane Gas Emissions - is Older Infrastructure Leakier?, AGU (2015) https://ui.adsabs.harvard.edu/abs/2015AGUFM.A43F0346W/abstract
[527] 5 Colo. Code Regs. § 1001-9, Pt. D, § II.E.4.e, https://drive.google.com/file/d/1ZwPwoAHVWEoRmPhoaI1UNEiP-RC9ZpI7/view.
[528] *Id.* at Pt. F, § P., pg. 262.
[529] 86 Fed. Reg. 63,192. EPA's comparison uses a site-level VOC-to-methane ratio of 0.28 to compare the 3 tpy methane threshold to the Colorado's VOC tiers, but tanks typically have a much higher VOC-to-methane ratio, which EPA's analysis does not take into account. This is particularly important since Colorado regulations are based on tank emissions when tanks are present.
[530] 5 Colo. Code Regs. § 1001-9, Pt. D, § II.E.4, https://drive.google.com/file/d/1JXzWUuPedxqHVCqiU6BdK3GJn_Z0x50X/view.

We replicated EPA's PTE analysis based on the Enverus 2019 well pads, using average component emissions per site, GHGRP tank emission factors, and a Monte Carlo simulation for pneumatic pump and pneumatic controller emissions.[531][532] We were able to predict the number of sites above and below the proposed 3 tpy threshold. From this analysis, we were able to assign each site to an inspection frequency under the new Colorado regulations (annual for >0 and <2 tpy VOC, quarterly for >=2 and <=50 tpy VOC, and monthly for >50 tpy VOC).[533] Under Colorado regulations, emissions are calculated using actual uncontrolled tank emissions (based on state-specified emission factors). If a site does not have a tank, the calculation is based on the site-wide actual controlled VOC emissions.

Our analysis finds that the majority of sites exempted under the EPA's proposed 3 tpy PTE threshold would be required to conduct annual inspections under the new Colorado tiered inspection frequencies. Moreover, a substantial number of EPA-exempted sites–approximately 16%–would be required to conduct quarterly inspections under Colorado tiered frequencies. Those EPA-exempted sites that would be required to conduct quarterly inspections under the Colorado requirements are typically oil-only sites reporting a low value for pneumatic controller emissions. Oil-only sites generally have lower predicted component-level emissions, putting them below the 3 tpy threshold, but the oil production drives uncontrolled tank emissions above 2 tpy VOC, leading to quarterly inspections under the Colorado tiering approach. The table below reflects representative sites that would be exempted under the EPA proposal but would be required to conduct regular inspections under the Colorado tiering approach.

[531] In order to recreate the site level dataset used by the EPA in their analyses, we first downloaded well level characteristic and production data for all wells with production in 2019 from Enverus Prism. We removed offshore wells by excluding Enverus Basin "GOM Offshore", Enverus State "CAO" and a series of counties designated as offshore (see API State and County Codes). After speaking with Enverus regarding their methods for creating their pad identifier, we identified an issue of exceptionally large pads (>25,000 active wells) created through their spatial model. Enverus is currently working to resolve this issue, and is open to feedback on a more accurate model. As a preliminary step, EDF decided to disaggregate sites by operator in order to split identified pads with more than one operator. This led to the creation of ~4,000 more pads from the original dataset (~.5%). To determine low-producing sites we calculated site level BOE produced per day and selected those below 15 BOEpd.

[532] Attachment G (Lyon PTE Analysis).

[533] For simplicity, we ignored differences for sites in proximity to occupied areas or in disproportionately impacted (DI) communities. This is a conservative comparison because many sites in Colorado are subject to more frequent inspections than in our simplified analysis.

**Figure 8: Comparison of Site-Level Emission Calculations Across Representative Sites**

| Well Pad Id | Well Count Type | 2019 Oil (bbl) Gas (MCF) | Marginal (Y/N) | Uncontrolled Tank Emissions (TPY) | | Component Emissions (TPY CH4) | Pneumatic Controller Emissions (TPY CH4) | Total Site Level Emissions (TPY CH4) | EPA LDAR Frequency | CO LDAR Frequency |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | CH4 | VOC | | | | | |
| 01-003-19986 | 1 OIL | 3370 | Y | 0.4 | 2.0 | 1.0 | 1.3872 | 2.8 | One-time | Quarterly |
| 01-023-20270 | 1 OIL | 1476 | Y | 0.2 | 0.9 | 1.0 | 1.3872 | 2.5 | One-time | Annual |
| 01-057-20126 | 1 GAS | 10738 | N | 0.0 | 0.0 | 1.9 | 0 | 1.9 | One-time | Annual |
| 42-159-00273 | 1 OIL | 3320 | Y | 0.4 | 2.0 | 1.0 | 1.3872 | 2.8 | One-time | Quarterly |

Colorado's site-level calculation more accurately predicts actual emissions and therefore places sites in more accurate monitoring tiers. Because EPA's proposed calculation will underestimate actual emissions in the vast majority of cases and fails to account for the well-documented problem of abnormal emission events caused by equipment failures, we recommend EPA revise the calculation by 1) employing emission factors that account for malfunctions, 2) using uncontrolled tank emissions, and 3) ensuring that every piece of equipment at the site, including flares, is included in the calculation.

To allow operators to more accurately calculate site-level emissions in a way that accounts for and reflects the substantial body of scientific literature documenting malfunctions and abnormal process conditions, EPA could, for example, rely on the peer-reviewed and publicly available model created by Rutherford et al.[534] Rutherford et al. constructs a bottom-up oil and gas production segment methane emissions estimation tool "based on the most comprehensive public database of component-level activity and emissions measurements yet assembled."[535] The "approach differs from the GHGI in that it applies a bootstrap resampling statistical approach to allow for inclusion of infrequent, large emitters, thus robustly addressing the issue of super-emitters."[536] The model's database includes roughly 3,700 measurements from six studies across a 12-fold component classification scheme, making it far more data-rich and recent than what underlies EPA's GHGI and GHGRP emission factors–much of which was published in the 1990s.

In both the Rutherford approach and the GHGI, emissions are calculated through two successive extrapolations: first from the component-level to the equipment-level; and second from the equipment-level to the national-level.[537] Extrapolations are performed by multiplying emission

[534] Rutherford et al., Closing the methane gap in US oil and natural gas production emissions inventories, 12 Nature Comms. 4715 (2021), https://www.nature.com/articles/s41467-021-25017-4#citeas [hereinafter "Rutherford 2021"]; see also id. at Supplementary Information, https://static-content.springer.com/esm/art%3A10.1038%2Fs41467-021-25017-4/MediaObjects/41467_2021_25017_MOESM2_ESM.pdf
[535] Rutherford 2021 at 2
[536] *Id.*
[537] *Id.* at 3, Figure 1.

factors by activity factors.[538] Emission factors reflect the average mass of pollutant per unit activity. Activities are often defined as operation of a component for a unit of time, resulting in emission factors with units such as kgCH4/flange/d. Activity factors are usually the number of sources, meaning the counts of equipment or components.[539]

The Rutherford model applies emission factors as reported in the individual studies and derives equipment-level emission factors by random re-sampling from a component-level database according to component counts per equipment and fraction of components emitting.[540] It also uses source-specific approaches for infrequent events (i.e., completions, workovers, liquids unloadings), methane slip from reciprocating engines, liquid storage tanks, and uncombusted methane from flares.[541]

EPA should require operators to calculate site-level baseline emissions using more accurate emission factors, like the averaged emission factors from Rutherford et al. The Rutherford tool provides equipment-level emission factors that are calculated by summing component-level emission factors according to estimated component counts per piece of equipment using methods described in Section 3.3 of the study and Section 5.2 for the GHGI. Table S2 and Table S3 present a harmonized comparison of equipment-level emission factors and activity factors between the Rutherford study and the GHGI for natural gas systems and petroleum systems, respectively.[542] These emission factors, derived from numerous recent peer-reviewed studies, will estimate site-level emissions more accurately than EPA's subpart W factors.

EPA also solicited comment on whether providing direct major equipment population emission factors that can be combined with site-specific gas compositions would provide a more transparent and less burdensome means to develop the site-specific emissions estimates than using a combination of major equipment counts, specific component counts per major equipment, and component-level population emission factors.[543] We believe this approach would be less burdensome and reduce potential inaccuracies in operator calculations. EPA should provide direct major equipment population emission factors that are representative of average emissions from such equipment, and require their use in a site-level emissions calculation. We do not recommend that EPA require operators to determine site-level baseline emissions by a site survey. Such an approach would disincentivize finding leaks, would allow operators to take non-representative surveys that would find artificially low baseline emissions, and would fail to account for subsequent equipment failures and intermittent emissions.

While the malfunction emission factors provided in the Rutherford model are a significant improvement from the subpart W factors, they only encompass the category of control malfunction to the extent that quantified emission events are available in the literature. If EPA uses these

[538] Rutherford 2021, Supplemental Information Part 2.
[539] *See id.*
[540] *Id.* at 3.
[541] *Id.* (Supplementary Methods 4 and 5).
[542] *Id.* at 11-12.
[543] 86 Fed. Reg. 63171

emission factors, it should also revise the calculation to reflect uncontrolled tank emissions, rather than allowing operators to subtract the fraction of emissions assumed to be controlled.

It is well-documented that tank control systems are often improperly designed and malfunction, leading to large emission events.[544] The improper design, construction, or maintenance of tank control devices (including flares, combustors (enclosed flares), and vapor recovery units) can reduce and entirely eliminate the capture or control efficiency of tank control devices.[545] Combustion devices can fail to ignite or have poor combustion efficiency, which causes methane slip.[546] Emissions may also not be fully captured if control systems are undersized or if condensed liquids in vent lines restrict the flow of gas, which can lead to tank overpressurization that triggers the release of gas from a pressure relief valve or tank hatch.[547] Further, tank hatches that are left open or improperly sealed can allow some portion of vented flash gas to circumvent control devices.[548]

EPA's proposal to use controlled tank emissions in the site-level calculation does not reflect the scientific consensus that tank control systems commonly fail.[549] Nor does it reflect the practice of leading states, like Colorado, which EPA has looked to in developing the tiered monitoring program. EPA should therefore revise the calculation to require use of uncontrolled tank emissions.

d. Recommendations - Well Sites

We support EPA's proposed quarterly OGI monitoring at well sites and tanks batteries, but urge the Agency to finalize stronger standards that require quarterly monitoring at all sites with potentially significant emissions—including smaller sites that may calculate emissions below 3 tpy using EPA's proposed methodology. If EPA retains the tiered structure, it should categorically exclude sites with failure-prone equipment from any tier subject to less frequent monitoring. We also urge EPA to increase monitoring frequencies at the largest sites where potential emissions are very high and monitoring is highly cost-effective. In this section, we discuss the issues with the proposed one-time monitoring requirement for sites below 3 tpy and potential solutions, issues with the co-proposed middle tier, and why more frequent monitoring is should be required at the largest sites.

***3 tpy Tier***

To remedy the numerous problems inherent in allowing smaller sites to forgo regular monitoring, which are discussed below, EPA should eliminate the 3 tpy tier and require quarterly monitoring

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[544] Lyon et al., Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites, 50 Env. Sci. Tech. 4877–4886 (2016), https://eplanning.blm.gov/public_projects/nepa/68426/102904/125847/Lyon_2016_Aerial_Surveys_of_Elevated_Hydrocarbon_Emissions_from_Oil_and_Gas.pdf

[545] *Id*. at 4884; see also EPA Observes Air Emissions from Controlled Storage Vessels at Onshore Oil and Natural Gas Production Facilities; United States Environmental Protection Agency: Washington, DC, 2015. Available from: http://www.epa.gov/sites/production/files/2015-09/documents/oilgascompliancealert.pdf.

[546] Lyon 2016 at 4884.

[547] *Id*.

[548] *Id*.

[549] *Id*.; *see also* sources cited *infra*, n. 551 below; Part IV.A.1.

at these sites, particularly if it retains the wellhead only exemption.[550] Quarterly monitoring is effective at reducing emissions and can be conducted at low cost at all sites. If EPA retains the tiering structure, it should exclude sites with known high-emitting equipment from any low-PTE category because of the potential for failure that could lead to major emission events. Numerous studies show that tanks, separators, flares, and gas-driven pneumatics commonly fail and lead to significant emissions.[551] EPA should categorically exclude any site with this type of equipment from qualifying for an exemption from routine monitoring through a low-PTE calculation. This would also streamline the rule's compliance and enforcement process because operators and inspectors could automatically eliminate certain well sites from qualifying for the exemption from regular monitoring simply by observing that certain kinds of equipment were present at the site, rather than having to calculate and verify PTE for those sites. We analyzed the potential impact of the 3 tpy threshold several different ways, summarized in the table below.

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[550] *See, e.g.*, CARB, *Oil and Gas Methane Regulation 2019 Annual LDAR Summary* (Nov. 2021) https://ww2.arb.ca.gov/sites/default/files/2022-01/CARBOilandGasMethaneRegulation2019AnnualLDARSummary-Revised.pdf (requiring quarterly monitoring regardless of site-level emissions potential).

[551] See Part X, Subsection A infra; Zavala-Araiza et al., Toward a Function Definition of Methane Super-Emitters: Application to Natural Gas Production Sites, 49 Env. Sci. Tech. 8167 (2015), https://pubs.acs.org/doi/pdf/10.1021/acs.est.5b00133; Lyon, D. R. et al. Aerial surveys of elevated hydrocarbon emissions from oil and gas production sites, 50 Env. Sci. Tech. 4877–4886 (2016) (finding that emissions from tank vents and hatches accounted for roughly 90% of all detected hydrocarbon sources emitting >3–10 kg per hour. Other sources observed included separator pressure relief valves, dehydrators and flares.); Rutherford et al., Closing the methane gap in US oil and natural gas production emissions inventories, 12 Nature Comms. 4715 (2021), https://www.nature.com/articles/s41467-021-25017-4#citeas (Figure 3 shows tanks as the largest emission source and biggest reason for disagreement with GHGI data. It also shows that flare methane emissions are underestimated in the GHGI and shows pneumatics and separators as large sources.); Zavala-Araiza et al., Super-emitters in natural gas infrastructure are caused by abnormal process conditions, 8 Nature Comms. 14012 (2017), https://www.nature.com/articles/ncomms14012; Tyner & Johnson, Where the Methane Is—Insights from Novel Airborne LiDAR Measurements Combined with Ground Survey Data, 55 Env. Sci. Tech. 9773 (2021) https://pubs.acs.org/doi/pdf/10.1021/acs.est.1c01572 ("More than half of emissions were attributed to three main sources: tanks (24%), reciprocating compressors (15%), and unlit flares (13%)."); 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://doi.org/10.1525/elementa.381 ("The majority of observed emission plumes were from liquid storage tanks (75.9% of all observed plumes), including emissions from pressure relief valves and thief hatches on the tank or from piping that connects to the tank. Well pads with control devices to reduce emissions from tanks (combustors or vapor recovery units) were more likely to have detected emissions.").

| Estimates of Sites and Emissions Above and Below 3 tpy[552] | | | | |
|---|---|---|---|---|
| | 1. PTE approach modeled after EPA approach | 2. PTE approach using GHGRP emissions | 3. Measured emissions approach (site-level emission factors from *Alvarez et al.*) | 4. Combined approach* (GHGRP emissions for PTE and site-level emission factors from *Alvarez et al.*) |
| Number of sites above 3 tpy | 563,185 | 224,376 | 611,983 | 224,376 |
| Number of sites below 3 tpy | 137,727 | 487,960 | 100,353 | 487,960 |
| Percentage of sites below 3 tpy | 20% | 69% | 14% | 69% |
| Total site-level emissions above 3 tpy | 3,839,070 | 3,371,798 | 11,065,199 | 6,971,494 |
| Total site-level emissions below 3 tpy | 263,174 | 462,433 | 65,863 | 4,159,569 |
| Percentage of site-level emissions below 3 tpy | 6% | 12% | 1% | 37% |
| Fugitive/abnormal emissions above 3 tpy | 1,323,612 | 487,508 | 8,324,970 | 5,130,693 |
| Fugitive/abnormal emissions below 3 tpy | 211,830 | 132,870 | 61,999 | 3,875,430 |
| Percentage of fugitive emissions below 3 tpy | 14% | 21% | 1% | 43% |

*For the combined approach, whether a site is above/below 3 tpy is based on PTE approach (using GHGRP emissions), but site-level emissions and APC emissions are calculated for those categories using the measured emissions approach

Under our first approach, we replicated EPA's PTE analysis. Following EPA's methods using 2019 Enverus Prism data and subpart W methods, we estimate that the 3 tpy threshold would exempt 20% of well sites (48% of oil wells and 19% of gas wells) from regular monitoring, forgoing up to 330,000 tons of methane reductions.[553] These 20% of wells comprise 14% of fugitive emissions, in line with what EPA estimates in the rule.

As a second approach to estimating the 3 tpy threshold, we used GHGRP data, extrapolated nationwide and disaggregated to the site level. First, GHGRP data were analyzed with a statistical model that uses production data and reported basin-level emissions to estimate county-level emissions from both reporters and non-reporters. Then, facility-level emission estimates were disaggregated down to an individual site level based on that site's percentage of the whole facility's production. This method of disaggregation likely overestimates emissions at lower production sites, which may not have all of the equipment found at larger sites. This method predicts that close

[552] *See* Attachment H (EDF Methane Policy Analyzer Methodology).
[553] Attachment G (Lyon PTE analysis).

to 70% of sites will be below the 3 tpy threshold, comprising 21% emissions. These first two methods likely approximate ways in which operators will estimate their own PTE. However, measurement studies have shown that these "bottom-up" approaches can significantly underestimate emissions at a site. Therefore, we also performed the analysis using measured site-level emission factors.

For the third approach shown in the table above, we used the site-level emissions factors (weakly correlated with production) from Alvarez et al. to predict site-level emissions.[554] Comparing these site-level emissions estimates to the 3 tpy threshold, we estimate that about 14% of sites are actually under a 3 tpy threshold, but that these sites only comprise around 1% of fugitive emissions. This method may overestimate emissions at some of the smaller, low-equipment site since emission factors aren't able to distinguish between sites with significant equipment and sites with very little equipment.

The fourth approach in the table represents a hybrid: calculating whether a site is above or below the 3 tpy threshold using the GHGRP emissions approach, but then calculating the percentage of site and fugitive emissions under that threshold using the Alvarez site-level emissions. This column approximates the potential impacts of operators using a PTE approach but having site-wide emissions in line with what Alvarez et al found. This approach finds that the roughly 70% of sites below the 3 tpy threshold comprise about 40% of fugitive emissions.

These methods demonstrate that it is difficult to predict exactly what percentage of emissions are left unmitigated by the 3 tpy threshold, but that it is likely to be substantial. Uncertainty around the number of sites that could be allowed to forgo regular monitoring and the magnitude of emissions potentially forgone strongly weigh against EPA finalizing the proposed approach to sites below 3 tpy. EPA should not finalize a loophole for sites below 3 tpy because doing so could leave sites responsible for up to 43% of fugitive emissions inadequately monitored. To look at this another way, if EPA finalizes its LDAR program as proposed and includes a one-time only inspection frequency for well sites under 3 tpy, our analysis shows this could reduce the overall effectiveness of its LDAR program by as much as half and leave millions of tons of pollution unaddressed. This one-time monitoring loophole thus significantly undermines the effectiveness of not just the fugitive monitoring program, but the entire proposal.

Further, the proposed loophole is not supported by cost considerations, scientific evidence of emissions from smaller sites, or any small business concerns. Leaving such a significant portion of easily achievable emission reductions on the table that could be cost-effectively cut is illogical and goes against EPA's directives under the Clean Air Act, the CRA Resolution (which, in practice, effectively nullified the low-production well exemption), and Executive Order 13,990. Forgoing these emission reductions will make it much more difficult for the Administration to meet its climate commitments made in Glasgow and under the Global Methane Pledge. It will also cause serious enforceability and compliance issues, setting up gamesmanship and creating room for inaccurate interpretations of regulatory obligations. Further, the proposed loophole raises

[554] Alvarez 2018.

serious environmental justice concerns that undercut the Administration's commitment to protecting frontline communities from the disproportionate burdens of pollution. Last, exemptions for low-utility sites allow operators to neglect maintenance and disincentivize proper closure, potentially exacerbating the orphan well problem.

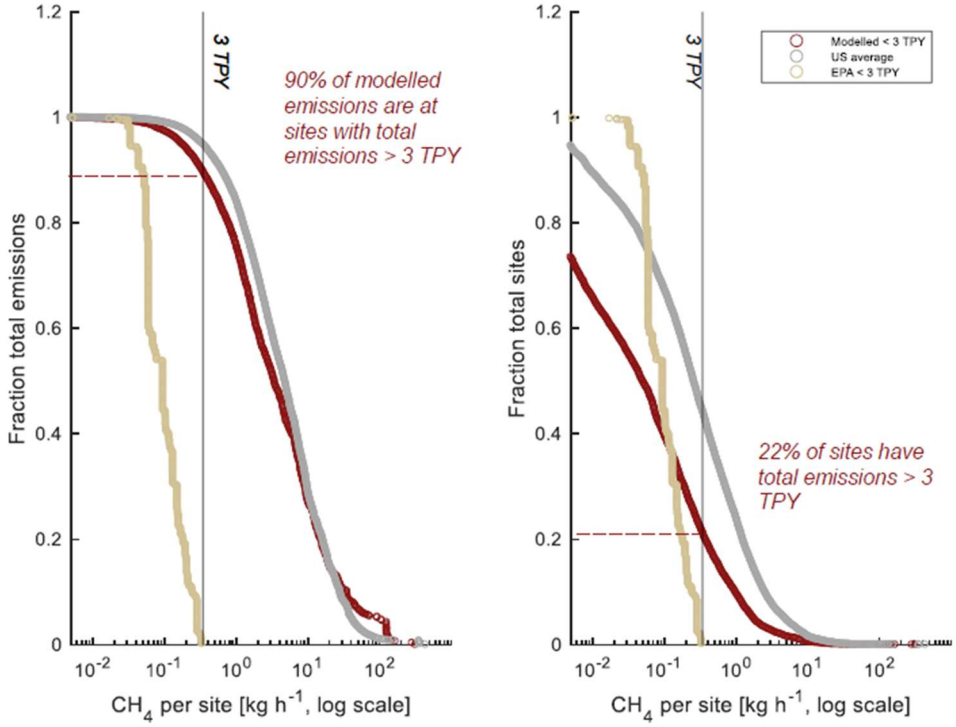
While the proposed one-time monitoring requirement differs from the low-production or marginal well exemption for new sources finalized under the last Administration, we expect the universe of sites falling into each category to be very similar.[555] The 3 tpy category does not include all low-producing or marginal sites (i.e., those producing an average of less than 15 BOE/d), but it will likely exempt hundreds of thousands of sites from regular monitoring. Marginal sites tend to have less equipment onsite, and therefore will calculate low potential emissions using EPA's proposed PTE calculation. Throughout this section we discuss marginal wells as a proxy for sites that will fall below 3 tpy, noting here that it is not a perfect comparison.

Related to the flaws in EPA's proposed PTE calculation for operators (discussed above), we think EPA's analysis estimating the number of sites and amount of emissions potentially falling below 3 tpy is flawed. Our attempt to recreate this analysis, which is shown in the table above and outlined in EPA's Appendix A, revealed multiple problems, and we believe it is unsuitable for estimating sites' PTE.[556] First, well site equipment counts, which are key inputs to the fugitive emission calculations, are applied randomly and do not account for likely relationships between production and equipment counts. Similarly, pneumatic controller and pump counts are assigned randomly even though higher production sites are expected to have higher equipment counts. In the likely case that low-production sites tend to have lower equipment counts, then this method of estimating site-level PTE over-assigns pneumatic pumps and controllers to these sites, which means EPA projects that less sites are below 3 tpy than would be expected. Second, these methods do not account for regional differences in emission factors or natural gas composition. Finally, and most critically, these approaches do not account for anomalous emission rates that can occur due to malfunctions. For example, a high production natural gas site with low equipment counts and little condensate production may have a low PTE based on these calculations, but if the separator dump valve is left open, then the site's emissions may be several orders of magnitude higher.

Using the Rutherford model, we separately evaluated the sites and emissions from sites that EPA would classify as below 3 tpy. We estimate that of all the sites EPA's analysis would place below 3 tpy, 22% actually have emissions above that threshold. Those 22% of sites account for 90% of total emissions from all sites that would qualify for the exemption under EPA's analysis. In other words, 90% of the unabated emissions that EPA estimates would result from the 3 tpy exemption originate from sites that should not, in fact, qualify for that exemption based on their actual emissions. Further, our analysis indicates that emissions from sites EPA would deem below 3 tpy PTE are underestimated by a factor of four.[557]

[555] Attachment G (Lyon PTE Analysis).
[556] *Id.*
[557] *Id.*

**Figure 9: Rutherford Model Analysis of Sites < 3 tpy**




***One-time monitoring is inadequate.*** EPA's proposal to require a one-time inspection at smaller sites is an inadequate approach for dealing with fugitive emissions from oil and gas sources, which are known to be intermittent, varying in size, and difficult to predict. For instance, operators may choose to conduct one-time monitoring during favorable conditions that do not accurately reflect the true extent of emissions from the site in question. And even if a one-time survey is conducted properly, it only represents a snapshot in time, and an equipment failure (particularly for sites with failure-prone equipment like tanks and flares) could cause the same site to begin experiencing large emissions any time after the survey. Under the proposed approach, super-emitters at these sites could go permanently undetected. Many of the smaller sites that would be allowed to conduct a one-time survey are older and declining in production, and are therefore more likely to be poorly maintained. Most of them have also never been subject to federal air-pollution regulation and have likely never upgraded any of their equipment. These older, declining sites are less valuable to operators who have little financial incentive to maintain them properly, resulting in components that may be rusted and in poor condition. All of these factors make sites below 3 tpy highly prone to leaks and equipment failures, and a one-time inspection does not resolve that problem.

Results from recent surveys conducted in the Permian Basin confirm that emissions from low production sites are recurrent and would not be mitigated by a one-time inspection and repair

standard.[558] From November 12-21, 2021, EDF contracted Leak Survey Inc. (LSI) to survey emissions across the Permian Basin using helicopter-based OGI. With an infrared camera mounted to an R44 helicopter with a gimbal for image stabilization, LSI visited 519 different upstream production sites. LSI then returned to 154 of these sites to collect repeat observations within a week's time. At each site, LSI noted any source of detectable methane emissions and recorded video—which are publicly available along with a complete methodology on Permianmap.org.

Over 80% of observations were linked to production data from Enverus Prism by totaling the amounts of oil and gas produced within a 175m radius buffer from the latitude and longitude reported by LSI. Roughly 60% of observations were from low-producing sites generating less than 15 BOE/d.

These low-producing sites had a higher rate of flare malfunctions (31.3%) when compared to higher production sites (9.4%). Additionally, the malfunctioning flares found at low-producing sites were almost all (90.5%) completely unlit and venting methane.[559] Even if only active for a short period of time, unlit flares release large amounts of methane into the atmosphere. For example, a flare with 98% combustion efficiency would have nearly fifty times higher emissions than normal when unlit. Possible causes of this high rate of malfunction include the intermittency of flares at these sites, due to low production levels, as well as likely less-frequent site visits by operators. The fact that low-producing sites more often exhibit one of the most consequential equipment malfunctions stresses the importance of surveying those sites frequently.

When comparing repeat observations from low-producing sites within a week, 56.3% of sites (54/96) had detectable emissions at some point. This includes emissions from all equipment types, such as flares, tanks, separators, and compressors. About one-third of sites had emissions during one site visit and not the other, while about one-quarter had detectable emissions during both visits. Of the sites with emissions observed during both visits, more than half of the sites had different pieces of equipment emitting on each day.

Although the analysis is segregated based on production, we expect similar emission trends between the low-producing sites surveyed and Permian sites classified as less than 3 tpy PTE, given the low production and relatively low equipment counts of the surveyed sites. Based on EPA's PTE methodology in RIA Appendix A, we estimate these sites would have a maximum emission rate of ~10 tpy for tank and fugitive emissions. One-time monitoring is inadequate because these sites often have highly intermittent emissions and emissions that emanate from variable pieces of equipment. At the low-producing sites where LSI collected repeat observations,

[558] Attachment B (PermianMAP November 2021 Flyover Results); *see also* EDF, Methodology for EDF's Permian Methane Analysis Project (PermianMAP) (Nov. 17, 2021), https://www.edf.org/sites/default/files/documents/PermianMapMethodology_1.pdf.
[559] See Attachment I (Warren Permian Slides 2021) ("Insights from Repeated Helicopter OGI on Methane Emissions and Flaring Performance across Industry Segments in the Permian Basin.").

a site visit on only one day would fail to mitigate emissions from 52.8% of sites that had multiple emission sources over two days.[560]

***Monitoring at smaller sites is cost-effective and feasible.*** Because EPA found quarterly monitoring at sites as low as 2 tpy cost-effective,[561] it should at least extend quarterly monitoring requirements to those sites. EPA acknowledges that regular monitoring at certain sites below 3 tpy would be cost-effective, but states that "[c]ost-effectiveness, however, is not the only relevant factor in setting the BSER, particularly for a source as numerous and diverse as well sites."[562] But EPA's stated rationales under the other BSER considerations are not supported by the record. EPA states that "[v]arious studies demonstrate that the vast majority of emissions come from a relatively small subset of wells," and because of this, "EPA would like to ensure that resources and effort are focused on those wells that emit the most methane and VOC."[563] While focusing resources on mitigating the greatest sources of emissions makes sense, that is no justification to categorically exempt other important sources from regular monitoring requirements.

Furthermore, EPA is mistaken in thinking that wells calculating a PTE of 3 tpy or less are not large sources of emissions. In fact, numerous studies, discussed below, have shown that smaller and older wells—many of which are likely to fall below 3 tpy according to EPA's proposed calculation methodology—are large and disproportionate emitters of methane.[564] Numerous studies and observations have shown that smaller wells can be, and often are, sources of super-emitters.[565] EPA's stated rationale does not apply and should not be used to justify an exemption for smaller sites.

Finally, there is no evidence of a shortage of resources. Most information available suggests that there are ample resources and that methane mitigation services are widely available and rapidly growing.[566] A recent report from Datu Research provides a comprehensive survey of the U.S. methane mitigation industry, which includes: firms that provide leak detection, measurement, and repair services; firms that provide advanced data analytics; firms that manufacture methane mitigation technologies; and firms that strategically advise operators on emission reduction planning.[567] All four categories of firms help oil and gas operators reduce fugitive emissions, but here we focus on the report's findings related specifically to services firms. Services firms are

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[560] On average, the sites that would still have emissions after one day of survey and repairs include one half of the sites that had emissions on one survey day and not the other, along with the sites that had emissions on both days but from different sources each day. These sites total 28.5 out the 54 sites seen to have emissions across both days.
[561] 86 Fed Reg. 63189.
[562] 86 Fed. Reg. 63189.
[563] 86 Fed. Reg. 63189-90.
[564] Attachment A (Omara AGU Slides 2021); EDF, Marginal Well Factsheet (2021), https://www.edf.org/sites/default/files/documents/MarginalWellFactsheet2021_0.pdf.
[565] Attachment B (PermianMAP November 2021 Flyover Results).
[566] Datu Research, *Find, Measure, Fix: Jobs in the U.S. Methane Emissions Mitigation Industry* (2021), https://www.edf.org/sites/default/files/content/FindMeasureFixReport2021.pdf [hereinafter "Datu 2021"]; Marcy Lowe, *Advanced Methane Monitoring: Gauging the Ability of U.S. Service Firms to Scale Up*, Datu Research (July 22, 2021), http://blogs.edf.org/energyexchange/files/2021/08/Advanced-Methane-Monitoring-Survey_Datu-Research_8-10-2021.pdf
[567] Datu 2021 at 8.

mostly performing leak detection, measurement and repair (108 firms), while 28 service firms provide advanced data analytics, and 13 provide strategic advisory to oil and gas operators. The report shows that this is a rapidly growing industry—finding a 90-percent increase in services firms over the 2017 report,[568] and deeming these numbers "almost certainly an undercount in all manufacturing and service categories."[569] Key findings include:

- The industry comprises dozens of job types, with annual salaries ranging from $37,150 to $140,960.
- Most of the firms (70%) are small businesses.
- Nearly 25% of the manufacturing firms and over 40% of the services firms were founded in the past 12 years.
- Firms are adding new U.S. employee locations. In 2021, Datu identified a total of 748 employee locations for manufacturing and service firms, an increase of 26% over the number previously identified.
- Firms anticipate growing jobs. Of 57 firms that responded to Datu's survey, 75% of the manufacturing firms and 88% of the service firms reported that if future state or federal methane emission rules were put in place, they would anticipate hiring more employees.
- These jobs appear poised to grow soon, in light of EPA's proposal and at least eight states preparing to either introduce new methane rules or expand the scope of existing ones.[570]

There are thousands of different operators, each of whom would be required to conduct monitoring across its own operations. Each operator has or can obtain their own resources to monitor their own sites, or otherwise contract with one of the many LDAR providers. EPA's attempt to focus resources on the largest sites ignores the diversity of ownership and facility types across the country. EPA's rationale is based on the incorrect notion that resources can be focused at the national-level, when in reality, any potential resource constraints would be faced at the operator-level.

Monitoring at smaller sites can also be done cost-effectively. In assessing cost-effectiveness, EPA should recognize that most operators own multiple wells, and EPA should group sites accordingly. In fact, for consistency with its analyses of higher-tpy wells, EPA could simply group all sites below 5 tpy together for cost-effectiveness considerations. But if EPA retains its current approach for lower-emitting sites, it should evaluate cost-effectiveness consistently at the same granularity across lower and higher tpy sites. In particular, EPA should seek to identify the point at which more frequent monitoring—six to twelve times per year—would be cost-effective and designate a separate category for those sites.

As described in detail above, EPA has greatly overestimated the costs of OGI monitoring. This is primarily due to an overestimate of recordkeeping and database management costs, an

[568] Datu Research, *Find and Fix: Job Creation in the Emerging Methane Leak Detection and Repair Industry* (March 2017), https://www.edf.org/sites/default/files/find-and-fix-datu-research.pdf
[569] *See* Datu 2021 at Appendix A (full list of firms and offerings).
[570] Datu 2021 at 3.

overestimate in the time necessary to conduct an OGI survey, and double counting of certain cost components. The overestimation of costs makes monitoring at these sites appear less cost-effective than is actually the case. Additionally, many sites below 3 tpy have not been subject to federal air pollution regulation before and will likely have old and failure-prone equipment. Because of this, we expect that many of the sites will contain large leaks when inspected, so monitoring would be more cost-effective than assumed by EPA.

Many operators that lack experience complying with federal regulations will simply hire contractors to conduct fugitive monitoring rather than creating an entire in house program. The same is true for smaller operators who may lack the staff and expertise to conduct fugitive monitoring. In this situation, some of the costs EPA has analyzed are inapplicable or should be reduced. For example, an operator that contracted with an OGI provider is unlikely to spend any time reading Appendix K or developing a fugitive monitoring plan. They may also contract for recordkeeping and data management services, further reducing costs. EPA should consider these possibilities and analyze costs appropriately.[571]

***Emissions from smaller sites are significant.*** Several recent studies demonstrate that smaller wells emit a significant percentage of their gas production—some venting all of their reported produced gas to the atmosphere, or even losing *more* gas through leaks than they produce for sale.[572] A recent study involving site-level measurements of over seventy well pads in the Permian Basin found that methane emissions are higher than in most other measured basins. This study also found no relationship between production and emissions, and that marginal wells had similar emissions to non-marginal wells.[573] Other recent observations in the Permian Basin have confirmed that marginal sites and even wellhead-only sites can be sources of the largest methane plumes.[574]

Another 2018 study investigated methane emissions characteristics to develop a new national methane emission estimate for the natural gas production sector. The study used site-level methane emissions data from over 1,000 natural gas production sites in eight basins, including 92 new site-level methane measurements in the Uinta, northeastern Marcellus, and Denver-Julesburg basins.[575] It examined natural gas production sites and categorized them as low (sites producing <100 Mcfd), intermediate (100-1000 Mcfd), and high (>1000 Mcfd). The study found that low natural gas

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[571] *See, e.g.*, Colorado Air Quality Control Commission, Regulatory Analysis (Dec. 5, 2019), https://www.edf.org/sites/default/files/content/Attachment%20B%20-%20Regulatory%20Analysis%2C%20Colorado%20Dep%E2%80%99t%20of%20Public%20Health%20and%20the%20Environment%20%28Dec.%205%2C%202019%29.pdf

[572] Deighton et al., *Measurements show that marginal wells are a disproportionate source of methane relative to production,* 70 J. of Air & Waste Mgmt. 1030 (2020), https://www.tandfonline.com/doi/full/10.1080/10962247.2020.1808115 ; *see also* EDF Marginal Well Factsheet (2021), https://www.edf.org/sites/default/files/documents/MarginalWellFactsheet2021_0.pdf .

[573] Robertson et al., New Mexico Permian Basin Measured Well Pad Methane Emissions Are a Factor of 5-9 Times Higher Than U.S. EPA Estimates, 54 Env. Sci. Tech. 13926 (2020), https://pubs.acs.org/doi/pdf/10.1021/acs.est.0c02927.

[574] Attachment B (PermianMAP November 2021 Flyover Results).

[575] Omara et al., Methane Emissions from Natural Gas Production Sites in the United States: Data Synthesis and National Estimate, 52 Env. Sci. Tech. 12915 (2018), https://pubs.acs.org/doi/10.1021/acs.est.8b03535 .

production sites "emit a larger fraction of their CH4 production" than the intermediate and high production sites.

A 2020 study involving direct measurements of methane and VOC emissions from marginal oil and gas wells in the Appalachian Basin of southeastern Ohio, all producing <1 BOE/d, found similar results.[576] The study found that marginal wells are a disproportionate source of methane and VOC emissions relative to production. It estimated that oil and gas wells in this lowest production category emit approximately 11% of total annual methane from oil and gas production reported in EPA's GHGI, even though they produce only about 0.2% of oil and 0.4% of gas in the U.S. per year.

Despite this wealth of data examining emissions from marginal sites, some industry stakeholders have claimed that EPA does not have enough information to regulate marginal sites and should wait for a pending study conducted by GSI Services with funding from the Department of Energy.[577] Yet this study looks only at emissions from sites that operators volunteered for the study and primarily utilizes component-level measurements that have been demonstrated to underestimate site-level emissions. Even so, drafts of the study show general agreement with skewed emission distributions but find lower average emission rates than other literature. Nothing contained in the draft study significantly changes what is already known about emissions from marginal sites.

Additionally, the most comprehensive study of marginal well site (<15 BOE/d) emissions to date, authored by Omara et al. and accepted for publication in *Nature Communications*, finds that these sites have production-normalized methane loss rates six to twelve times higher than other sites and represent roughly half (37-75%) of all U.S. production site methane emissions.[578] While 80% of production sites nationwide contain these marginal wells, they only produce 6% of the nation's oil and gas output. Nationally, about 60% of marginal sites are ultra low-production sites, producing less than 2 BOE/d. These wells generate just a trickle of usable product despite disproportionately harming human health and the environment.

The Omara et al. study uses available production data from Enverus to assess marginal sites' regional distribution, production characteristics, and operator profiles. Using this data in combination with data on marginal well site emissions previously collected from a diversity of regions across the U.S., the study generates a new national estimate of the total methane emissions from marginal well sites and assesses the significance of these emissions in comparison to emissions from all U.S. production sites.

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[576] Deighton et al., *Measurements show that marginal wells are a disproportionate source of methane relative to production* (2020).

[577] *See, e.g.*, IPAA, SER Comments (Aug. 12, 2021), https://www.ipaa.org/wp-content/uploads/2021/08/SER-Comments-GO-WV.IPAA_.TIPRO-color.pdf .

[578] Omara et al., Methane emissions from U.S. marginal oil and gas wells, __ Nat. Comms. __(2021) (accepted for publication); Attachment A (Omara AGU Slides 2021); March 12 EDF Meeting Slides Attachment - Marginal Wells, available here: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0317-0107 .

Omara et al.'s assessment carries significant policy implications for effective mitigation of U.S. oil and gas methane emissions. It finds that marginal well sites are abundant and that their methane losses occur at high rates exceeding 10% of site-level methane production.[579] Field-based observations point to avoidable maintenance-related issues as a key driver of emissions at marginal well sites, particularly at older, lower-producing sites that tend to suffer from prolonged lack of attention from their owners or operators[580]–the precise problem that would be rectified by regular monitoring requirements. Even as their production declines over time, marginal sites' emissions continue from both routine and nonroutine, but avoidable, sources. Marginal sites also display the fat-tailed emission distribution commonly observed in the oil and gas sector.[581] Identifying high-emitting sites and uncovering the root causes of excessive emissions is key to mitigation.

Recognizing the disproportionately large role that low-producing sites play in contributing to total emissions in the U.S. is critical to developing appropriate regulations and achieving targeted reductions.[582] Exemptions for marginal sites risk leaving half of production site emissions unabated without adequate justification. Given that marginal sites generate less than 6% of domestic oil and gas production, there are no legitimate concerns that requiring their owners to regularly monitor them and repair equipment leaks would significantly harm domestic energy production.

These studies underscore the critical importance of regular leak detection and repair at the smallest of sites—many of which would be exempt under EPA's proposed 3 tpy threshold. These wells—which number in the hundreds of thousands—produce very little usable product, yet they are large and disproportionate polluters. EPA must ensure emissions from these wells are minimized by requiring regular monitoring and repairs.

***Smaller wells are owned by large companies.*** EPA also partially justifies the 3 tpy exemption on a finding that "given the diversity of ownership, while our cost assumption that distributes the costs of recordkeeping evenly across 22 sites within a company-defined area is a reasonable estimate for the population as a whole, it may underestimate the costs and therefore overestimate the cost-effectiveness for owners with fewer than 22 well sites (and conversely, underestimate cost-effectiveness for owners with more than 22 well sites)."[583] Again, this consideration is incorrectly applied to smaller sites: any different treatment on the basis of production (or potential emissions) will likely disproportionately benefit larger operators who own many sites. As shown in the below figure, the vast majority of marginal sites are owned by companies operating 50 or more sites–and this is without considering those companies' additional ownership of non-marginal sites.

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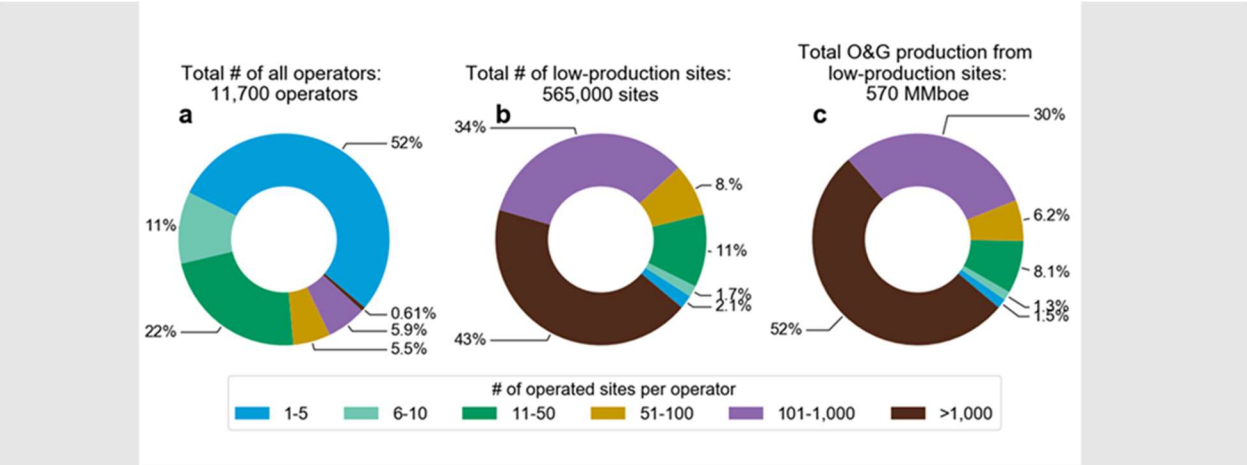
[579] *Id*.
[580] Deighton et al., *Measurements show that marginal wells are a disproportionate source of methane relative to production*. 70 J. Air & Waste Mgmt. 1030-1042 (2020); Omara et al.,. *Methane emissions from conventional and unconventional natural gas production sites in the Marcellus Shale region*, 50 Env. Sci. Tech. 2099—2107 (2016).
[581] Attachment A (Omara AGU Slides 2021).
[582] *Id.*
[583] 86 Fed Reg 63190.

**Figure 10: Operator Profiles of Marginal Well Sites**[584]




Throughout the proposal, EPA seems to believe that smaller sites are owned by smaller companies that operate fewer wells. EPA provides no justification for this assumption, and EDF analyses of Enverus Prism data shows that it is incorrect. Ninety-two percent of marginal well sites are actually owned by larger companies, defined as those that operate 25 or more sites. EDF analysis also shows that more than three-quarters of marginal wells are owned by companies that operate more than one hundred well sites and generate hundreds of millions in gross revenue each year.[585]

**Figure 11: Ownership and Revenues Profiles for Marginal Well Sites**[586]

**Well Site Ownership and Gross Revenue by Operator Size**

| Operator Size (# Of Well Sites) | Operators | Well Site Counts Total | % of Well Sites Marginal | % of Total Well Sites Marginal | Gross Revenue (MLN USD) Total | Per Operator Revenue (MLN USD) Total |
|---|---|---|---|---|---|---|
| **Small operators** | | | | | | |
| < 5 | 6,894 | 13,019 | 93% | 2% | $1,930 | $0.28 |
| 5 to 25 | 2,890 | 36,935 | 92% | 6% | $7,489 | $2.59 |
| *Small operators total* | *9,784* | *49,954* | *93%* | *8%* | *$9,418* | *$0.96* |
| **Large operators** | | | | | | |
| 25 to 100 | 1,691 | 83,900 | 91% | 13% | $18,607 | $11 |
| > 100 | 875 | 570,246 | 80% | 79% | 310,179 | $354 |
| *Large operators total* | *2,566* | *654,146* | *82%* | *92%* | *$328,786* | *$128* |
| **TOTAL** | **12,350** | **704,100** | **82%** | **100%** | **$338,205** | **$27** |

Sources: Enverus, EIA

Notes:

1) Marginal well sites are defined as sites with average combined oil and gas production of less than 15 BOE per day for 2019 (where 6 MCF = 1 BOE).

2) The average WTI Cushing OK spot price for 2019 is used for oil prices.

3) The average Import price for 2019 is used for gas prices.

4) The well site definition is pulled from Enverus using the "ENV WELL PAD ID" field. Enverus allows multiple operators to be on a single well site; this analysis disaggregates Enverus' well site definition by operator.

***Tiering creates enforcement and compliance problems.*** A tiering system that is based on self-determined potential to emit calculated via a complex mathematical formula is prone to human error and gamesmanship. It will also be more difficult to enforce because determining the

[584] Attachment A (Omara AGU Slides 2021).

[585] As noted above, although marginal production does not directly correlate to PTE, many marginal sites will fall below 3 tpy using EPA's proposed calculation.

[586] Attachment J (Wolfe & Lackner Operatorship Analysis).

applicable regulatory standard for a site requires a regulator to conduct the same complex mathematical calculation. And a site's PTE is likely to change over time, as equipment is added and removed and as production levels vary. EPA has proposed that operators would have to re-calculate PTE every time equipment is added or removed from the site, creating further potential for error and confusion.[587] If EPA retains a tiered approach, categorically excluding sites with failure-prone equipment from tiers subject to less frequent monitoring is a solution that would ease some enforcement concerns.

In her article *Next Generation Compliance: Preventing Widespread Violations that Threaten Climate Goals*, Cynthia Giles highlights methane regulations for oil and gas production as "the classic situation in which compliance is likely to be bad."[588] The oil and gas sector has many characteristics that make it prone to poor compliance, including: "millions of widely dispersed sources; emissions that are hard to observe or measure; industries that know government's chances of figuring out they are in violation are low; and many states that are unwilling to hold operators accountable."[589] She also points out that the "widespread and faulty assumptions that most companies comply, and that enforcement can take care of the rest, are obviously incorrect here," arguing that more stringent standards will lead to even greater noncompliance as operators—many of whom have never been subject to federal methane regulation—are faced with new costs.[590] Her topline recommendations for federal oil and gas regulations are to 1) aim for clarity and simplicity, 2) minimize exemptions, and 3) require frequent monitoring.[591] She explains these recommendations in detail:

> When a regulation is clear and opportunities to obfuscate or avoid complying are few, compliance will be better. The fewer exceptions and special conditions it contains, the less likely a regulation is to give companies a chance to confuse the matter and thereby evade or delay compliance. Obligations that depend on individual discretionary judgment on a site-specific basis create loopholes that undercut compliance. Numeric, straightforward, measurable obligations are likely to produce better environmental results than more nuanced and theoretically stringent requirements that are not actually implemented.
>
> . . . .
>
> [W]henever regulators draw a line and say on this side you are regulated and on that side you aren't it creates powerful incentives for more companies to find a way to be – or claim to be – on the unregulated side of the line. Exempting lower-

[587] 86 Fed. Reg. 63170.
[588] Cynthia Giles, *Next Generation Compliance, Part 4: Preventing Widespread Violations that Threaten Climate Goals*, Harvard EELP, at 43 (April 2021), http://eelp.law.harvard.edu/wp-content/uploads/Cynthia-Giles-Part-4-FINAL.pdf [hereinafter *Next Generation Compliance*].
[589] Giles, *Next Generation Compliance* at 45; *see also* EPA, *New Owner Clean Air Act Audit Program for Upstream Oil and Natural Gas Exploration and Production Facilities, Questions and Answers*, at 1 (March 29, 2018), https://www.epa.gov/sites/production/ files/2018-06/documents/qaoilandnaturalgasnewowner auditprogram.
[590] Giles, *Next Generation Compliance* at 47.
[591] *Id.* at 48-49.

> producing wells is also tough to justify from a pollution control perspective; low-production wells can leak just as much as higher producing ones. It also creates a compliance black hole by motivating companies to improperly claim the exemption, while at the same time eliminating the monitoring and reporting that would allow regulators to know what is going on. Multiply that by over a million wells and you see why this kind of exemption creates both pollution and compliance trouble.[592]

Giles's concerns are directly applicable to the proposed exemption from regular monitoring for sites below 3 tpy, and to the co-proposed middle tier (discussed below). EPA has proposed to draw lines between categories of sites for differential treatment and plans to let operators themselves calculate where their sites fall. EPA has thus built in pathways to noncompliance and created incentives for operators to find ways to qualify for less frequent monitoring. And once an operator has decided its site is below 3 tpy and conducted a one-time inspection, that site will no longer be monitored or subject to recordkeeping and reporting standards, creating the black hole described above.

Enforcement is likewise complicated and made less effective by the tiering structure. Inspectors will be unable to simply visit a site and determine its compliance obligations. Rather, they will have to conduct a PTE calculation, which they will then compare to the operator's own calculation, and will have to resolve any resulting discrepancies before determining the source's compliance obligations. Nor can inspectors determine a site's compliance obligations through by monitoring, since PTE is not reflective of the site's actual emissions. These concerns are exacerbated by the resource limitations that EPA and states will face when enforcing these rules at hundreds of thousands of sources nationwide. For these reasons alone, EPA should eliminate the PTE-based tiered monitoring system and require quarterly monitoring at all sites. At a minimum, EPA should include equipment-based categorical exclusions so it is visibly apparent upon a site inspection what frequency of monitoring is required.

***Exempting smaller sites raises serious environmental justice concerns.*** An exemption from regular monitoring at any site with the potential for significant emissions would allow that site to spew dangerous, health-harming pollution into nearby communities undetected for years. The proposed one-time inspection cannot guard against this both because equipment failures are difficult to predict and because large emission events occur intermittently. This means an operator might inspect a site one time and find no leaks, but a subsequent malfunction—like a thief hatch left open—could occur and go undetected for long periods. Nearby residents, including vulnerable populations like children and the elderly, would bear the brunt of this pollution, inhaling health-harming and toxic pollution.

The people residing within half a mile of an active oil and gas site include many vulnerable populations. Using the U.S. Census Bureau's American Community Survey 5-year estimates for

[592] *Id.* at 48-49 (citations removed).

2015-2019[593] and the Center for Disease Control's (CDC) PLACES dataset,[594] we were able to estimate the populations living within a half mile radius of the previously identified low production 2019 well sites using aerial apportionment. This method determines the area encompassed within a half mile buffer radius of all affected wells, and overlays those buffers onto census tracts to calculate the percentage of each tract comprised of buffers (i.e. the area of each tract within a half mile of an affected well). The areal apportionment method assumes that populations are spread evenly across a given census tract (excluding water bodies), and thus we are able to estimate the populations at a census tract level of those living within a half mile of a low production well site. This method is commonly used in published literature utilizing distance-based analysis.[595]

While some studies have used finer spatial resolutions such as census block groups, we performed our analysis using census tracts in order to minimize margin of error in census estimates. Census tracts, and even larger regions such as zip codes, have often been used in similar analyses.[596] We used a half mile radius because recent scientific evidence indicates close proximity to oil and gas development is associated with HAP exposure and other adverse health impacts for local populations.[597]

The results of this analyses can be seen below in Figures 12 and 13 It should be noted that the two subgroups (existing vs. OOOOa affected low producing wells) do not sum perfectly, as people may live within half a mile of both types of wells.

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[593] U.S. Census Bureau. (2021). 2015-2019 American Community Survey 5-year Estimates. Retrieved from https://www2.census.gov/geo/tiger/TIGER_DP/2019ACS/.

[594]Centers for Disease Control and Prevention. (2021) Retrieved from https://chronicdata.cdc.gov/500-Cities-Places/

[595] See, e.g. Long, J.C.S., Feinstein, L., Birkholzer, J.T., Foxall, W., An Independent Scientific Assessment Of Well Stimulation In California, Vol. 3, California Council on Science and Technology (2016), available athttps://ccst.us/reports/an-independent-scientific-assessment-of-well-stimulation-in-california-volume-3/ ; J. Chakraborty, J., Maantay, J.A., and Brender, J.D. Disproportionate Proximity to Environmental Health Hazards: Methods, Models, and Measurement, 101 Am. Journal of Pub. Health. S27–S36 (2011),https://ajph.aphapublications.org/doi/pdfplus/10.2105/AJPH.2010.300109 .

[596] See, e.g., Srebotnjak, T. and Rotkin-Ellman, M., Drilling in California: Who's at risk?, Nat. Res. Def. Council (2014) https://www.nrdc.org/sites/default/files/california-fracking-risks-report.pdf ; Mohai P. and Saha, R., Reassessing racial and socio-economic disparities in environmental justice research, 43(2) Dhttps://www.edf.org/sites/default/files/content/Roy%20Thompson%20111d%20Declaration%20FINAL.pdfemography 383–399 (2006)https://pubmed.ncbi.nlm.nih.gov/16889134/; Kearney G., and Kiros G.E., A spatial evaluation of socio demographics surrounding National Priorities List sites in Florida using a distance-based approach, 8(33) Int'l J. Health Geogr. (2009),https://ij-healthgeographics.biomedcentral.com/track/pdf/10.1186/1476-072X-8-33.pdf

[597] *See* Declaration of Ananya Roy and Tammy Thompson ¶¶22-33, https://www.edf.org/sites/default/files/content/Roy%20Thompson%20111d%20Declaration%20FINAL.pdf.

**Figure 12: Demographics of People Residing Near Oil and Gas Well Sites[598]**

| Well Type | Well Age[599] | Total Population within 1/2 mile | Children Under 5 within 1/2 mile | Adults over 64 within 1/2 mile | People of Color within 1/2 mile | People in Poverty within 1/2 mile |
|---|---|---|---|---|---|---|
| Low-Producing | All | 7,930,000 | 480,000 | 1,340,000 | 2,040,000 | 1,130,000 |
| Low-Producing | Existing | 7,850,000 | 477,000 | 1,300,000 | 2,000,000 | 1,120,000 |
| Low-Producing | New | 230,000 | 14,000 | 38,000 | 68,000 | 34,000 |

**Figure 13: Health Characteristics of People Residing Near Oil and Gas Well Sites**

| Well Type | Well Age | Adults with Asthma within 1/2 mile | Adults with Chronic Heart Disease within 1/2 mile | Adults with COPD within 1/2 mile | Adults with Stroke within 1/2 mile |
|---|---|---|---|---|---|
| Low-Producing | All | 780,000 | 550,000 | 670,000 | 290,000 |
| Low-Producing | Existing | 770,000 | 540,000 | 666,000 | 286,000 |
| Low-Producing | New | 23,000 | 16,000 | 19,000 | 8,000 |

These communities bear the brunt of the environmental, economic, and public health impacts resulting from leaks. These groups can be especially vulnerable to air pollution impacts or may face greater barriers to medical care. In some cases these groups live near wells in disproportionately high numbers. For example, there are almost 10% more people living in poverty near wells compared to the percentage of people in poverty nationally. Adults with Asthma, CHD, COPD and Stroke were found to live near wells in disproportionately high numbers as well, ranging from ~8% to 29% higher than national averages. While some groups are found at similar levels near wells and nationwide alike, Native Americans live near wells at rates more than 30%

[598] For additional data see: https://www.edf.org/federalmethanemap/

[599] Wells that were drilled or modified after September 18, 2015 are "new" or "modified" wells remaining wells are considered "existing".

higher than would be expected based on nationwide statistics (and almost 90% higher near new low-producing wells).

Recently, sixteen members of the Congressional Hispanic Caucus asked that the agency strengthen the proposal, specifically opposing any carve outs for smaller sites because of the implications to frontline communities, including 1.81 million Latinos that live within a half mile radius of an oil and gas well.[600] They urged EPA to "address this issue by enacting comprehensive requirements for frequent leak inspections, without exceptions for smaller wells." We likewise urge EPA to require regular monitoring at these sites to protect frontline communities.

***Exemptions may exacerbate the orphan well problem.*** Another problem with the 3 tpy threshold, which is further discussed in Part IV.J, is that by exempting these frequently older sites from regular inspections and federal requirements, operators will have no reason or incentive to take care of them and ensure they are properly shut down. In fact, the exemption creates the opposite incentive: because an operator would not have to spend any money or take any steps to comply with the regulations, they would be incentivized to leave the site as is rather than properly shut it down. EPA should structure regulatory requirements to ensure proper maintenance and closure as well sites reach the end of their productive and economically viable lives. By failing to require regular inspections at smaller wells, EPA is enabling poor maintenance and disincentivizing proper plugging and closure.

As regulations become more stringent and leading operators endeavor to reduce their emissions, operators increasingly offload underperforming assets to smaller companies that lack shareholder and other external pressure to reduce emissions.[601] A lack of stringent regulatory requirements for these under-performing assets makes them more attractive to prospective buyers who lack both internal emission reduction goals and would not face regulatory pressure to cut emissions.[602] And to larger companies seeking to reduce their overall emissions, these are "assets with disproportionately high emissions primed for disinvestment."[603] This problem is borne out in emissions data for companies, which shows that "five of the industry's top ten emitters of methane

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[600] Letter from Rep. Barragan et al. to Administrator Regan (Dec. 22, 2021), https://barragan.house.gov/wp-content/uploads/2021/12/Barraga%CC%81n-CHC-Methane-Letter-Final.pdf

[601] Hiroko Tabuchi, *Here Are America's Top Methane Emitters. Some Will Surprise You.*, New York Times (Oct. 2021) https://www.nytimes.com/2021/06/02/climate/biggest-methane-emitters.html ("As the world's oil and gas giants face increasing pressure to reduce their fossil fuel emissions, small, privately held drilling companies are becoming the country's biggest emitters of greenhouse gases, often by buying up the industry's high-polluting assets.").

[602] *See, e.g.*, Zachary Mider and Rachel Adams-Heard, *Diversified Energy Said Emissions Fell. Now It Says They Didn't: U.S. gas producer told investors one thing, regulators another,* Bloomberg Green (Oct. 20, 2021), https://www.bloomberg.com/news/articles/2021-10-20/gas-producer-diversified-energy-said-emissions-fell-now-it-says-they-didn-t

[603] Andrew Baxter and Gabriel Malek, *Oil and gas companies, investors, and policymakers all have important roles to play to solve the problem of transferred emissions*, Investor Engagement (Nov. 2021), https://business.edf.org/insights/why-we-need-leadership-to-close-the-transferred-emissions-loophole/

. . . are little-known oil and gas producers, some backed by obscure investment firms, whose environmental footprints are wildly large relative to their production."[604]

A lack of federal requirements to detect and fix leaks may make these assets more attractive to buyers and allow the high-polluting practice of extending the lives of aging, underperforming sites, even while they often lack the funds to pay for plugging.[605] Exempting smaller sites from regular inspections could thus encourage companies to buy up these underperforming and high-polluting sites and keep them operating longer before potentially going bankrupt, leaving taxpayers holding the bag.[606] Among many other reasons described herein, EPA should subject these sites to similar requirements as other well sites to avoid inadvertently incentivizing and subsidizing irresponsible business models.[607]

***Co-proposed 3-8 tpy Tier***

EPA should not adopt a middle tier of well sites subject to semiannual monitoring because sites in this tier have potential to leak in significant quantities and can be cost-effectively monitored more frequently. EPA appears concerned that monitoring for this tier may be costly or burdensome and cites Colorado regulations as justification for co-proposing semiannual monitoring for these sources[608] However, the disparities in coverage resulting from EPA's proposed controlled PTE calculation versus the uncontrolled VOC calculation used in Colorado are significant, as explained above.[609] Even if VOC and methane are equated, the same site would calculate a very different and higher PTE under Colorado regulations and would therefore fall into a higher tier subject to more frequent monitoring.

In addition, Colorado has recently strengthened its LDAR program and requires more frequent and routine monitoring across the board, such that all well production facilities, no matter the size, are subject to at least annual monitoring. Notably, Colorado increased the frequency of monitoring at the middle tier (ranging from 2-12 tpy VOC) from semiannually to quarterly or bi-monthly—six times per year. The lowest tier, from 0-2 tpy, must conduct annual or semiannual monitoring. And, in the highest tiers, monthly monitoring is required. Below is a tiered monitoring chart reflecting Colorado's recent revisions to Regulation 7.

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[604] Hiroko Tabuchi, *Here Are America's Top Methane Emitters. Some Will Surprise You.*, New York Times (Oct. 2021) https://www.nytimes.com/2021/06/02/climate/biggest-methane-emitters.html (citing CATF, *Benchmarking Methane and Other GHG Emissions of Oil & Natural Gas Production in the United States* (June 1, 2021), https://www.catf.us/resource/benchmarking-methane-emissions/.

[605] See, e.g., Zachary Mider and Rachel Adams-Heard, Diversified Energy Said Emissions Fell. Now It Says They Didn't: U.S. gas producer told investors one thing, regulators another, Bloomberg Green (Oct. 20, 2021), https://www.bloomberg.com/news/articles/2021-10-20/gas-producer-diversified-energy-said-emissions-fell-now-it-says-they-didn-t.

[606] Haynes Boone, *Oil Patch Bankruptcy Monitor* (June 30, 2021), https://www.haynesboone.com/-/media/project/haynesboone/haynesboone/pdfs/energy_bankruptcy_reports/oil_patch_bankruptcy_monitor.pdf?rev=61c2606a5be547598c8d716d1a795c39&hash=97ECA4B149560404B19497FA37CB2B50.

[607] *See* Part IV.J (Abandoned Wells) (discussing end-of-life well issues).

[608] 86 Fed Reg. 63192.

[609] *See* Figure 8.

**Figure 14: Colorado LDAR Monitoring Frequencies[610]**

| Table 5 - Well Production Facility Component Inspections on or after January 1, 2023 | | |
|---|---|---|
| Thresholds (per II.E.4.g.) | | |
| Well production facilities (rolling twelve-month tpy) | Approved Instrument Monitoring Method Inspection Frequency | AVO Inspection Frequency |
| > 0 and < 2 | Annual | Monthly |
| > 0 and < 2, located within 1,000 feet of an occupied area | Semi-annual | Monthly |
| > 0 and < 2, located in the 8-hour ozone control area and within a disproportionately impacted community | Semi-annual | Monthly |
| ≥ 2 and ≤ 50 | Quarterly | Monthly |
| ≥ 2 and ≤ 12, located within 1,000 feet of an occupied area or within a disproportionately impacted community | Bimonthly | Monthly |
| > 12, located within 1,000 feet of an occupied area or within a disproportionately impacted community | Monthly | |
| > 20, well production facilities without storage tanks | Monthly | |
| > 50, well production facilities with storage tanks | Monthly | |

As shown here, Colorado's required LDAR frequencies are stronger or equal to EPA's proposed frequencies at every single tier. EPA should at minimum finalize quarterly monitoring at all sites above 3 tpy, but should also require more frequent monitoring, especially at the largest sites. EPA did not evaluate bi-monthly monitoring (six times per year), instead skipping from quarterly to monthly in concluding that increased monitoring was not incrementally cost-effective. Overall cost-effectiveness is the metric that EPA should rely on first and foremost, not incremental cost-effectiveness. Nonetheless, in many cases, the data show that the incremental cost of increased monitoring is, in fact, within what EPA considers cost-effective. And an evaluation of bi-monthly monitoring is likely to show that increased monitoring at higher tpy sites is incrementally cost-effective. As Colorado did, EPA should therefore evaluate bi-monthly monitoring as a requirement for any tier of wells for which it is cost-effective.

As discussed previously, utilization of the Rutherford model indicated that 22% of sites that could be placed in the <3 tpy PTE tier are actually likely to emit more than 3 tpy.[611] This analysis required matching our 2019 wellsite dataset to 2019 GHGRP facilities and wells. We were then able to determine which facilities had average emissions per site below 3 tpy. Of the approximately

[610] 5 Colo. Code Regs. § 1001-9, Pt. D, § II.E.4, https://drive.google.com/file/d/1JXzWUuPedxqHVCqiU6BdK3GJn_Z0x50X/view.
[611] Attachment K (Rutherford PTE Slides).

530,000 wells in EF_W_ONSHORE_WELLS_2019 from the 2019 GHGRP Subpart W dataset[612] we were able to match ~460,000 wells with production in 2019 (330,000 sites) from Enverus Prism. Of the sites matched to GHGRP facilites, more than 50% of sites were determined to be at facilities with average site level emissions below 3 tpy and 25% of sites between 3 and 8 tpy. Average site level emissions were calculated using reported 2019 emission data and the number of matched sites at each facility. While the sites below 3 tpy emitted ~11% of reported 2019 facility emissions, they produced almost 30% of matched 2019 production. Comparatively, sites between 3-8 tpy emit almost 25% of reported emissions but produce the lowest fraction of production, 24%. While we would need to run the Rutherford Model for these sites specifically, it is reasonable to assume that with a more accurate prediction method, we would also find that sites originally placed in the 3-8 tpy tier have higher emissions in reality.

***Sites Above 8 tpy***

We support EPA's proposal to require quarterly monitoring at sites above 8 tpy (although, as we discuss below, still more frequent monitoring requirements should apply to some sources). Quarterly monitoring–and in many cases more frequent monitoring–is well-justified, cost-effective, and necessary to achieve substantial emission reductions. EPA should require at minimum quarterly monitoring at all sites where it is cost-effective, including those from 3-8 tpy and all or at least some sites below 3 tpy.

Additionally, either in the regulatory text or in Appendix K, EPA should more clearly define monitoring frequencies. For example, quarterly monitoring should not simply occur once every quarter or four times per year; EPA must specify that there must be at least 60 days but no more than 90 days between monitoring inspections at the same site. Clarifying the time permitted between site inspections is crucial for achieving emission reductions and ensuring leaks are timely detected and fixed.

At large sites, where an abnormal process event could emit even more massive amounts of pollution into the air, quarterly monitoring may not be sufficient, and EPA should therefore require monthly monitoring where it is cost-effective to do so.[613] Leaving such events undetected and unrepaired for multiple months at a time could have devastating climate and health impacts.[614] By EPA's own analysis, monthly monitoring at these sites is extremely cost-effective, even resulting in cost savings for the largest sites.[615] It is arbitrary for EPA to so closely scrutinize cost-effectiveness at the smallest of sites on grounds that those sites have lower potential emissions but not require more frequent monitoring at the sites with the highest potential emissions—especially where increased monitoring could be achieved at low or zero net cost.

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[612] EPA 2019 Greenhouse Gas Reporting Program Subpart W (2021). Retrieved from Envirofacts: https://www.epa.gov/enviro/greenhouse-gas-customized-search.

[613] Our modeling with FEAST, discussed more below, shows that monthly monitoring is highly effective at reducing super-emitter events. *See* Attachment L (FEAST National Slides).

[614] *See, e.g.*, Conley et al., *Methane emissions from the 2015 Aliso Canyon blowout in Los Angeles*, CA, 351 Science 1317 (2016), https://www.science.org/doi/10.1126/science.aaf2348.

[615] TSD at Table 12-13a, 12-13b.

It is also incrementally cost-effective to increase monitoring from quarterly to monthly at sites above 20 tpy.[616] EPA should more granularly evaluate whether it might be incrementally cost-effective to increase to monthly monitoring at sites between 15 and 20 tpy. EPA should also evaluate the incremental cost-effectiveness of increasing to bi-monthly (six times per year) monitoring.

The D.C. Circuit has repeatedly held that section 111 requires the "maximum practicable degree" of control.[617] The Clean Air Act does not necessarily require EPA to set a standard at a level that reflects the maximum level of control that is technologically possible, but it does require the agency to maximize the level of emission reductions that can be achieved while giving reasonable consideration to the other statutory factors.[618]

With regard to costs, this means that the standard must achieve the maximum degree of emission reductions without becoming exorbitantly costly or ruinous for the regulated industry.[619] Monthly monitoring at the highest tpy sites is well within the range EPA has deemed reasonable; in some cases, it even results in negative costs, while achieving at least 10% more emission reductions than quarterly monitoring and even better results if super-emitter reductions are considered. EPA should thus require monthly monitoring at any site where it is cost-effective.

e. Recommendations - Compressor Stations

In this section, we explain why EPA should increase monitoring frequency to monthly or bi-monthly at all compressor stations, why subcategorization based on throughput is not warranted, and why availability of parts is not a valid concern.

***Compressor station fugitive emissions are significant.*** Compressor stations are large sources of fugitive emissions, particularly gathering and boosting compressor stations. Research has found "that CH4 emissions from gathering are substantially higher than the current EPA GHGI estimate and are equivalent to 30% of the total net CH4 emissions in the natural gas systems [2014] GHGI," with the majority coming from gathering facilities.[620] Another more recent study found that combustion slip from compressor engines was the single greatest source of emissions at gathering stations.[621] "Because throughput was a direct function of operating compressors, and 82% of compressors in the field campaign were operating at time of measurement, combustion slip was

[616] TSD at Table 12-13c.
[617] *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 437 (D.C. Cir. 1973) (citing Summary of the Provisions of Conference Agreement on the Clean Air Amendments of 1970, 116 Cong. Rec. 42384, 42385 (1970))
[618] *Sierra Club v. Costle*, 657 F.2d 298, 330 (D.C. Cir. 1981); *see also id.* at 326 (a standard of performance must "reduc[e] emissions as much as practicable.").
[619] See *Essex Chemical Corp.,* 486 F.2d at 433; P*ortland Cement Ass'n,* 513 F.2d at 508; *Lignite Energy Council,* 198 F.3d at 933.
[620] Marchese et al., *Methane Emissions from United States Natural Gas Gathering and Processing*, 49 Env. Sci. Tech. 10718 (2015), https://pubs.acs.org/doi/pdf/10.1021/acs.est.5b02275; see also Vaughn et al., Comparing facility-level methane emission rate estimates at natural gas gathering and boosting stations. 5 Elem. Sci. Anth.71 (2017) (finding average facility level emission rate 17-73% higher than prior national study by Marchese et al.).
[621] Zimmerle et al, Methane Emissions from Gathering Compressor Stations in the U.S., (2020) https://pubs.acs.org/doi/pdf/10.1021/acs.est.0c00516.

the single strongest driver of the relationship between station throughput and total methane emissions."[622]

To evaluate emissions and reductions from LDAR at compressor stations, EPA relied on a model plant analysis. As explained earlier in these comments and in our comments on the proposed reconsideration of OOOOa, however, using model plants greatly underestimates actual emissions because the analysis does not account for super-emitter events.[623]

***More frequent monitoring should be required at compressor stations.*** EPA found the weighted average for single pollutant cost-effectiveness of monitoring at compressor stations (without gas savings) to be $855/ton of methane for quarterly inspections and $1,807/ton for monthly inspections.[624] On a multipollutant basis, these values drop to $428 and $903, respectively.[625] In 2016, EPA considered values as high as $2,185/ton to be cost-effective for methane reductions.[626] Thus, because the weighted average, even without gas savings, is well within EPA's traditional cost-effectiveness range and because compressor stations are significant sources of fugitive emissions, EPA should increase the required monitoring at these sources to monthly. If for some reason EPA concludes that monthly monitoring is not cost-effective for all compressor stations, it should then require bi-monthly inspections for the tier of compressor stations where monthly inspections would exceed EPA's cost-effectiveness threshold.

In analyzing monitoring costs at compressor stations, EPA has likely (and significantly) overestimated the cost per OGI survey by assuming each survey will take between 10.6 and 28.1 hours.[627] An analysis conducted by MJ Bradley of Air Emission Reports submitted to EPA by oil and gas companies shows that an average compressor station LDAR survey takes just 2.8 hours.[628] Based on this, EPA's assumed OGI survey costs for compressor stations are likely far too high. Additionally, the double counting and overestimating of various cost components described earlier in this section also apply to EPA's estimates for compressor stations. Because of these overestimates, EPA should revise its cost-effectiveness numbers for compressor stations too.

We also emphasize that EPA should revisit its repair cost assumptions for compressor stations to ensure it is not double counting costs that should be or already are attributed to other work practice standards, like those for reciprocating and centrifugal compressors. If an operator discovers that a compressor is malfunctioning through an OGI survey, that repair cost is properly attributed to the underlying compressor standards that require operators to have functioning compressors that operate without significant combustion slip.

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[622] *Id.*
[623] 2018 Comments at 109- https://www.edf.org/sites/default/files/content/Joint_Environmental_Comments_on_EPAs_Proposed_NSPS_Reconsideration.pdf.
[624] TSD at 12-40.
[625] TSD at 12-41.
[626] See 86 Fed. Reg. 63159 (citing 80 Fed. Reg. 56627; NSPS OOOOa Final TSD at 93).
[627] TSD at 12-19, 12-20.
[628] Attachment C (Memo from MJB to EDF 2018). These reports were accessed using EPA's WebFIRE site, available at https://cfpub.epa.gov/webfire/.

In the sections below, we summarize EPA's cost-effectiveness findings for different classes of compressor stations. These data reveal that monthly monitoring requirements are appropriate for each kind of facility, notwithstanding that they are overestimates of costs.

***Gathering and Boosting Compressor Stations***. For quarterly monitoring at gathering and boosting compressor stations, the cost per ton of methane reduced is $1,006 and with gas savings considered, the cost per ton of methane reduced is $824. For monthly monitoring, the cost per ton of methane reduced is $2,219 and if gas savings are considered, the cost per ton of methane reduced is $2,038.

***Transmission Compressor Stations***. For quarterly monitoring, the cost per ton of methane reduced is $617. For monthly monitoring, the cost per ton of methane reduced is $2,219 and if gas savings are considered, the cost per ton of methane reduced is $2,021. Transmission facilities do not own the natural gas; therefore, revenues from reducing the amount of natural gas emitted as the result of equipment leaks was not further analyzed for this segment.

***Storage Compressor Stations***. For quarterly monitoring, the cost per ton of methane reduced is $211. For monthly monitoring at storage compressor stations, the cost per ton of methane reduced is $1,094. Once again, storage facilities do not own the natural gas; therefore, revenues from reducing the amount of natural gas emitted as the result of equipment leaks was not estimated for this segment.

Monthly monitoring at all compressor stations is thus within the range EPA considers cost-effective.[629] Even ignoring cost savings, the cost for monthly inspections at gathering and boosting and transmission compressor stations–$2,219–is only slightly higher than values that EPA has in the past found cost-effective ($2,185). Adjusted for inflation, the $2,219 value may even be lower than $2,185. And many other available estimates of costs suggest that monthly monitoring is even cheaper and more cost-effective than EPA's analysis indicates.

EPA justifies its selection of quarterly rather than monthly monitoring on incremental cost-effectiveness. However, the agency has not explained why incremental cost-effectiveness should matter more than overall cost-effectiveness, nor has it examined whether bi-monthly (six times per year) monitoring might be incrementally cost-effective. Furthermore, if emissions from super-emitters are considered, monthly monitoring will be far more effective at reducing emissions and more incrementally cost-effective as well.

In Colorado's most recent rulemaking, the Air Pollution Control Division estimated the cost-effectiveness of quarterly inspections at compressor stations to be $3,279.14 per ton VOC and $46.04 per mtCO2e, without incorporating the estimated annual value of recovered gas.[630] With gas savings, the numbers fell to $2,659.55 and $37.63, respectively. New Mexico also recently

[629] 86 Fed. Reg. 63,196 ("Based on the single pollutant approach, both quarterly and monthly frequencies are reasonable for methane emissions . . . . Further, both frequencies are reasonable under the multipollutant approach when considering the total cost effectiveness compared to a baseline of no OGI monitoring.").
[630] Colorado Air Pollution Control Division, Revised Final Economic Impact Analysis for Regulation 7 & 22 Revisions at 17-18 (December 2021), https://drive.google.com/drive/folders/1mDU8Wc3iB_E4lj36R8AK_y8ptcU83Yao

evaluated the cost-effectiveness of quarterly OGI at compressor stations and estimated a value of $3,331/ton VOC.[631] These VOC-designated costs are considerably lower than the level that EPA has identified in the proposal for determining the cost-effectiveness of VOC controls.[632] Likewise, the CO2e-designated costs values are markedly lower than the central 2022 values reported in the Interagency Working Group's Interim Global Social Cost of Carbon TSD.[633] As noted above, the Interagency Working Group's values represent a highly conservative estimate of the true social cost of greenhouse gases, and any compliance costs falling below those figures should certainly be considered cost-effective.

***Replacement parts can be easily procured.*** At this point, existing compressor station owners and operators are aware they will be subject to fugitive monitoring and repair requirements in the coming years. They have at least three years to begin preparing for compliance—including by ordering and stockpiling parts they know are likely to fail and cause large leaks. This is more than sufficient time for these operators to plan and avoid a situation where a component fails and they are unable to obtain that component without specially ordering it. EPA's focus must be on ensuring major leaks are quickly fixed, and on not hypothetical parts shortages occurring in 2025 and beyond.

As EPA is aware, many of the same components and pieces of equipment exist across the oil and gas supply chain. And many of those same components and pieces of equipment are known as sources of fugitive emissions and ones that commonly malfunction. Compressor station operators already know which parts are likely to fail and cause fugitive emissions and will therefore require repair. And if they don't know already, they have the next three years to prepare by inspecting sites, determining which components need to be upgraded or are likely to fail, and begin ordering spare parts.

If EPA were to allow delayed repairs based on the availability of parts, which it should not, the delay should not be permitted for major leaks. Operators should at a bare minimum have at least one replacement part on hand for any major leak event. This type of poor planning cannot excuse delays in the repair of large emission events. Additionally, to the extent EPA does permit some degree of compliance flexibility due to the lack of availability of certain equipment parts, it must require the operator to support its claim through rigorous documentation, including but not limited to: a reasonable explanation of why the operator did not have a spare part on hand; a justification of why the equipment failure was not foreseeable at any point from the date of the proposed regulations until the date of failure; proof that such failures are not common at similar compressor stations of similar age; maintenance and inspection records supporting the non-foreseeability of the failure; proof and date that the replacement part was ordered immediately upon detection; and proof that the part was installed as quickly as possible upon receipt.

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[631] *Id.*

[632] 86 Fed. Reg. 63,155 ("As discussed in that section, the EPA finds cost-effectiveness values up to $5,540/ton of VOC reduction to be reasonable for controls that we have identified as BSER in this proposal.").

[633] Interagency Working Group on Social Cost of Greenhouse Gases, *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990*, Table A-1: Annual SC-CO2, 2020 – 2050 (in 2020 dollars per metric ton of CO2) (Feb. 2021) (listing the social cost of carbon dioxide in 2022 as $53 per metric ton at a 3% discount rate).

### 3. *Advanced Monitoring Alternative*

We strongly support EPA's proposal to include an advanced monitoring alternative that also requires periodic OGI surveys to detect smaller leaks. Advanced technologies offer a promising pathway to more frequent and cost-effective screening for large emission events. EPA should increase or at least maintain the frequency of advanced monitoring, which can be done cost-effectively, and should consider allowing a broader variety of technologies with varying detection capabilities. EPA should ensure that the framework it adopts also allows for continuous monitoring technologies, which have the potential to be highly effective at reducing emissions. In this section, we discuss the costs and availability of advanced monitoring technologies, the legal basis for allowing advanced monitoring, how such a standard may be structured in the regulations, and how continuous monitoring can be incorporated.

#### a. Costs and Availability of Advanced Technologies

Advanced monitoring technologies are already widely available and in use by leading operators.[634] Many of these technologies are highly effective and inexpensive. And many companies providing advanced methane mitigation services are domestic and provide well-paying jobs in geographies across the country. These technologies are particularly capable and efficient at screening large areas for emissions, although layered approaches utilizing multiple techniques may be most appropriate for finding and fixing smaller (but collectively significant) leaks. Operator experience, scientific use and testing, and simulation modeling provide estimates of the cost and effectiveness of different approaches that can inform regulatory approaches.

A recent comprehensive survey from Datu Research shows that advanced leak detection services are widely-available. Datu's survey of services firms offering advanced methane monitoring reveals their ability and plans to scale up in response to new federal methane regulations.[635] Firms offering advanced monitoring services have nearly doubled in the past four years alone, and more than a quarter are already capable of surveying over 300 well sites per day. More than half of firms surveyed said they could serve at least 100 more well sites per day than they currently serve by 2023. Nearly half (47%) said they could scale up to serve more than 500 well sites per day; these respondents comprised those using fixed sensors, airplanes, satellites, or a combination of these technologies. Eighty-nine percent of the firms surveyed can detect emissions at the equipment level, while 53% can detect at the component level. The firms also operate broadly across major oil and gas basins, with at least 32% having a presence in every basin, and 74% operating in the Permian. Datu's findings underscore that advanced methane detection technologies are already widely available to operators and can easily be incorporated into EPA standards.

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[634] *See* Datu Research, *Find, Measure, Fix: Jobs in the U.S. Methane Emissions Mitigation Industry* (2021); EPA, *Methane Detection Technology Workshops*, https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-methane-detection-technology-workshop.

[635] Marcy Lowe, *Advanced Methane Monitoring: Gauging the Ability of U.S. Service Firms to Scale Up*, Datu Research (July 22, 2021), http://blogs.edf.org/energyexchange/files/2021/08/Advanced-Methane-Monitoring-Survey_Datu-Research_8-10-2021.pdf.

EPA's Methane Detection Technology Workshop held in August 2021 further confirmed the availability of advanced technologies and included information on their effectiveness, while providing useful cost estimates.[636] Key takeaways from the workshops are summarized below:

- **Layered approaches are needed.**[637] The data now available suggests that, in their current form, advanced technologies should be used to supplement—not replace—OGI monitoring. Advanced technologies can quickly and cost-effectively detect super-emitters, achieving significant reductions. But traditional approaches with lower detection limits, like OGI, are still necessary to detect and mitigate widespread smaller leaks that cumulatively represent a large portion of the sector's total emissions. In recognition of this fact, EPA has appropriately proposed that companies choosing to comply the proposed LDAR requirements through the use of advanced technologies must also complete an OGI survey of their affected facilities at least once each year.

- **Advanced technologies are cost-effective and significantly reduce emissions.**[638] Advanced technologies are widely used by leading operators, small and large, to improve operations and reduce emissions to achieve company-set goals, even without regulatory requirements. Operators described conducting advanced monitoring voluntarily on top of OGI regulatory requirements based on the cost-effective improvements secured in operations. Exxon represented that semiannual aerial surveying was essentially equivalent to semiannual OGI; its modeling showed semiannual aerial reductions just below 60%.[639] Exxon also encouraged EPA to pursue strong regulations incorporating advanced technologies.[640] Triple Crown Resources said that it "saw a 90% decrease in emission volumes in comparison to the first [aerial] survey after just eight months and three surveys."[641] Learning from the surveys, Triple Crown said it was able to take preventative steps, like re-weighting thief hatches and conducting routine flare checks.[642] Triple

[636] EPA Methane Detection Technology Workshops (August 23 and 24, 2021), audio: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0317-0183; transcripts: https://www.regulations.gov/document/EPA-HQ-OAR-2021-0317-0181
video: https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-methane-detection-technology-workshop
Day 1 Video Link: https://www.youtube.com/watch?v=KfY50npQ0sM
Day 2 Video Link: https://www.youtube.com/watch?v=lQcUhMG24X0
[637] *See id.* (presentations by: David Lyon, Erin Tullos, Matt Johnson, Triple Crown, Jonah, Project Astra, Project Falcon, BPX, Conoco, and Exxon).
[638] *See id.* (presentations by: Triple Crown, TRP, Jonah, BPX, Conoco, and Exxon.)
[639] EPA, Methane Tech Workshop Transcript Day Two at 53, https://www.regulations.gov/document/EPA-HQ-OAR-2021-0317-0181.
[640] *Id.*
[641] EPA, Methane Tech Workshop Transcript Day One - Part 1 at 39, https://www.regulations.gov/document/EPA-HQ-OAR-2021-0317-0181
[642] *Id.*

Crown also found that the "first survey paid for itself in approximately five days. Over the next four months, detecting and repairing those emission sources generated $400,000 of profit."[643] Further, "fly[ing] over all of Triple Crown's 23,000 acres, survey[ing] over 200 assets including pipelines, deploy[ing] a follow-up OGI camera crew, and roustabout crew to verify and repair every leak that was detected by Kairos" cost Triple Crown "less than $25,000."[644]

- **Comprehensive coverage is already deployed by leading operators.**[645] Triple Crown indicated that it was able to survey across its facilities, not just OOOOa-affected facilities using advanced screening approaches.[646] Jonah Energy stated that increasing the frequency of its surveys to monthly and using continuous monitoring significantly reduced emissions and led Jonah to conduct monthly surveys at all its sites.[647] BPX has established a goal to install measurement technologies at all major oil and gas processing sites by 2023[648] and that it began using drones across all its operations in 2019.[649] Exxon said it can survey 30-65 facilities per day using aerial surveys,[650] which allow for near pinpointing of sources and immediate deployment of repair technicians.[651]

- **Workshop cost estimates:** OGI – $600/site/inspection[652]
  Aerial – $100-300/site, quarterly for $1,600/facility[653]
  Drone – $2,700-3,500/annually[654]
  Continuous – $1,000-5,000 annually[655]

b. Overview of Advanced Technologies

A broad range of advanced methane monitoring technologies are available and can be utilized by operators to detect, pinpoint, and quantify fugitive emissions. Over the past decade, rapid innovation has led to a diverse array of advanced methods: there are now at least 100 distinct methane measurement technologies that are commercially available for leak monitoring in the oil

[643] *Id.* at 40.
[644] *Id.*
[645] *See* presentations by: Triple Crown, Jonah, BPX, Conoco, and Exxon.
[646] EPA, Methane Tech Workshop Transcript Day One - Part 1 at 40, https://www.regulations.gov/document/EPA-HQ-OAR-2021-0317-0181
[647] EPA, Methane Tech Workshop Transcript Day One - Part 1 at 62, https://www.regulations.gov/document/EPA-HQ-OAR-2021-0317-0181
[648] EPA, Methane Tech Workshop Transcript Day Two at 38, https://www.regulations.gov/document/EPA-HQ-OAR-2021-0317-0181.
[649] *Id.* at 41.
[650] *Id.* at 59.
[651] *Id.* at 50.
[652] *Id.* (Erin Tullos and Arvind Ravikumar).
[653] *Id.* (Erin Tullos, Arvind Ravikumar, and Matt Johnson (TRP $1,600/facility/quarterly)).
[654] *Id.* (TRP).
[655] *Id.* (Erin Tullos and TRP.)

and gas industry.[656] Widespread adoption and deployment of emerging technologies—even in the absence of regulatory requirements—demonstrates their cost-effectiveness and the opportunity to incorporate these methods into a regulatory scheme.

Methane monitoring technologies can be classified in several ways. Generally, technologies can be grouped into screening (i.e., aerial) and close-range (i.e., OGI and Method 21). Most close-range methods are handheld instruments that can diagnose individual leaks at the component scale. Screening technologies are those that can quickly find abnormally emitting facilities for follow-up with close-range methods. Detection capabilities vary greatly and typically increase with proximity to the emission source. However, technologies that monitor from farther away, like aircraft and satellites, are usually much faster and can cover broad geographic areas frequently.[657]

A comprehensive monitoring program that utilizes both screening and close-range technologies is likely to be highly effective.[658] In this type of program, screening technologies are used to monitor across broad geographic areas frequently to quickly detect the largest emission sources, which can represent 50% or more of total emissions. Close-range methods are used for both directed follow-up to pinpoint emission sources detected during screening and to routinely monitor sites for smaller leaks that would not be detected by screening methods.

The use of screening technologies has grown rapidly across the oil and gas sector in the last few years.[659] Screening frequently for large leaks can be more effective than less frequent, close-range inspections.[660] Typically, screening surveys cannot identify leaks at the component level nor distinguish permissible, vented emissions from fugitive and abnormal emissions. To diagnose and repair leaks, most screening methods must be paired with close-range systems. Differentiating between leaks and venting requires planning and recordkeeping to match detected emissions to planned venting events.

In general, detection sensitivity declines with spatial scale of measurement, meaning those farthest from the source will be less able to detect smaller emissions. However, there is typically a trade-off between sensitivity and survey speed, and the cost of deployment tends to decline as speed increases. For example, aerial surveys with high detection limits are low cost and can quickly cover broad areas but will only detect the largest emission events, missing smaller leaks.

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[656] Highwood Emission Management, *Technical Report: Leak detection methods for natural gas gathering, transmission, and distribution pipelines*
(2022) https://highwoodemissions.com/pipeline-report/ [hereinafter "Highwood 2022"].
[657] *Id.*
[658] Fox et al., *A review of close-range and screening technologies for mitigating fugitive methane emissions in upstream oil and gas*, 14 Env. Res. Letters 53002 (2019), https://iopscience.iop.org/article/10.1088/1748-9326/ab0cc3.
[659] *See* Highwood 2022; Datu 2021; *see also* Scientific Aviation, *Major Energy Companies Join Forces to Battle Methane Emissions* (March 2021), http://www.scientificaviation.com/major-energy-companies-join-forces-to-battle-methane-emissions/.
[660] Attachment L (FEAST National Slides).

**Figure 15: Temporal and Spatial Capabilities of Detection Technologies[661]**

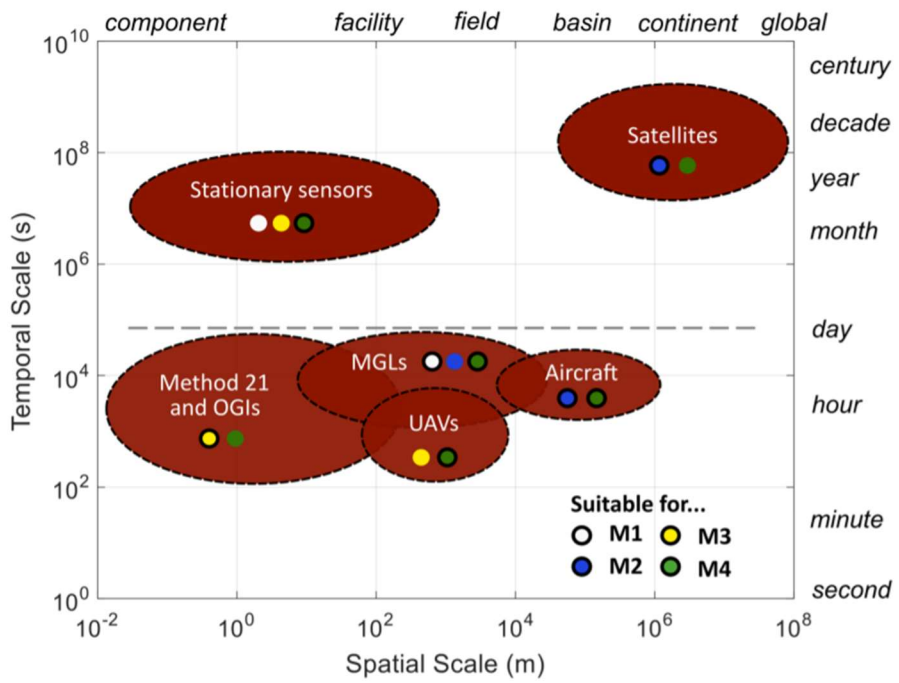


**Figure 2.** Technology classes categorized based on the spatial and temporal extent of coverage. Colored dots represent suitability for measurement motivations 1–4. Dots without black borders either show promise or may be useful in a limited capacity.

A major outstanding challenge for screening technologies is their inability to discern vented from fugitive emissions.[662] Under most regulations, including EPA's proposal, venting is authorized in certain limited circumstances, creating potential problems for screening approaches. Detection of permissible high-emission events during screening could trigger follow-up ground surveys for events like blowdowns or tank flashing. Needless searching for these events may increase the cost of screening and disincentivize use of advanced technologies. Reducing instances of permissible emissions through other regulatory standards would alleviate much of this problem, as eliminating permissible venting would enable screening techniques to become more sensitive to the presence of fugitive emissions. Moving toward zero emission standards across the full range of affected facilities could eventually eliminate this issue entirely. Another solution is to reduce detections by screening only for sources that greatly exceed venting limits, relying on ground-based monitoring to resolve smaller events. Rigorous reporting and notification of large events would also allow operators and regulators to know when a high emission event was planned and avoid sending follow-up ground crews if advanced screening detected planned emissions.

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

Methane detection methods differ not only in performance but also in the types of sources that can be identified and how these sources are characterized. For example, a recent study using aerial surveys identified far fewer–but much larger–sources than handheld surveys performed at the same time (39 vs 357 sources, respectively).[663] Many of the leaks found during the handheld survey were too small to be seen by aircraft, while many of the largest emission events occurred at a small number of sites and may have been missed during the ground inspection. This indicates that full coverage of a system is most effective with multiple technologies. Simulation studies have shown that a combination of technologies can be effective under the right circumstances.[664]

When considering the performance of an advanced monitoring approach, it is important to distinguish between technologies and methods. Technologies include deployment platforms and sensor types, while methods include the work practices and follow up procedures. Understanding the methods in combination with a technology is critical when evaluating performance.[665] For example, larger emissions detected during screening must be paired with shorter repair timelines in order to achieve substantial reductions. For certain recurring or major emission events, engineering analysis might be required to diagnose and fix the underlying operational issues. Varying dispatch thresholds for follow-up is another work practice that can greatly influence the effectiveness of an approach. For example, if follow-up and repair is only required for the largest leaks, overall mitigation effectiveness will be lower than a work practice requiring follow-up on all detected leaks.

Technologies typically consist of deployment platforms and sensors. Deployment platforms can be broadly classified into the following categories:

- **Aircraft** – Various sensor types can be mounted on helicopters and small airplanes to detect methane emissions over relatively long periods while covering longer distances. Like drones, aircraft can collect data in three dimensions.

- **Unmanned Aerial Vehicles (UAVs)** – Also called drones, these can reach dangerous or hard-to-reach places and can fly very close to the source of plumes. They can be equipped with OGI cameras and other relatively small, lightweight sensor devices and, like aircraft, can operate in three-dimensional space.

- **Mobile Ground Labs (MGLs)** – Consisting of a vehicle with a global positioning system and a methane sensor, MGLs enable an operator to generate a map of methane concentrations along the vehicle's path. Because it is limited to the path (usually a road), this method collects data in a two-dimensional space.

- **Continuous Monitoring** – These systems are unique in that they are stationary. Fixed sensors are installed in a facility—typically in high-risk areas—to provide

[663] Tyner & Johnson, *Where the Methane Is—Insights from Novel Airborne LiDAR Measurements Combined with Ground Survey Data*, 55 Env. Sci. Tech. 9773 (2021), https://pubs.acs.org/doi/10.1021/acs.est.1c01572
[664] Fox et al., *A review of close-range and screening technologies for mitigating fugitive methane emissions in upstream oil and gas*, 14 Env. Res. Lett. 053002 (2019), https://iopscience.iop.org/article/10.1088/1748-9326/ab0cc3/pdf.
[665] *See id.*

continuous, real-time readings of methane concentration. These devices will trigger an alarm if concentrations exceed certain limits. These systems can also be tower-based and used to cover multiple sites.

- **Satellites** – Satellites can be equipped to measure methane concentrations in the troposphere. These readings can be combined with other data to identify large sources of emissions.[666]

Sensing modes include point measurement of ambient mixing ratios, path integrated laser-based measurements (active imaging), and column-integrated passive imaging. Sensing modes can be broadly categorized as:

- **Point sensing** (in plume sensing) – Point sensors range from simple solid-state metal oxide detectors to complex cavity ringdown spectrometers (CRDS) and gas chromatographs. Points sensors can be deployed on any platform that passes through methane plumes.

- **Active imaging** (remote sensing) – Active imaging systems generate sources of light that traverse methane plumes, reflect off a remote surface, and return to a detector. Changes in the reflected light are used to infer methane concentrations along the path. A common example is Light Detection and Ranging (LiDAR).

- **Passive imaging** (remote sensing) – Passive imaging systems use natural light to measure methane concentration in the atmosphere. They are used in all types of platforms, ranging from OGI cameras to satellite imagery.

- **Non-methane** – Many sensors infer the presence of leaks by measuring variability in pressure, temperature, vegetation growth, physical disturbance of equipment or the areas nearby, and other proxies.[667]

Over the past decade, there has been considerable innovation in advanced methane detection strategies. Advancements have occurred in technologies and deployment platforms, but there has also been innovation in how approaches can be most effectively structured. The use of diverse sources of information, simulation modeling, machine learning, and other techniques is now common for detecting leaks and prioritizing their repair.[668] Below we discuss in greater detail commonly used advanced approaches.

***Aircraft.***[669] Passenger aircraft, both planes and helicopters, can be equipped with various sensor technologies and used at various elevations and frequencies. These factors, along with the survey methodologies used, affect survey speed and minimum detection limit. Some aerial technologies

[666] Datu Research, *Find, Measure, Fix* (2021); Highwood Emission Management, *Technical Report: Leak detection methods for natural gas gathering, transmission, and distribution pipelines* (2022), https://highwoodemissions.com/pipeline-report/.
[667] Highwood 2022.
[668] *Id.*
[669] *Id.*

or methods may use remote sensing and fly higher and faster or use a technology with a lower sensitivity to cover more sites in a day. Other aerial technologies and methodologies may call for lower and slower flights or use a technology with a higher sensitivity that detects more emission events but covers fewer sites in a day.

The primary limiting factors for aerial methods are weather (high winds, precipitation, cloud cover), variable reflectivity from uneven snow cover, and flight permits. Aircraft detection limits range from a few kilograms of methane per hour to tens of kilograms per hour. This technology is readily available and has undergone multiple, controlled release tests to verify performance metrics. The main advantage of aircraft technologies is the greater geographic coverage, which allows surveying of thousands of sites per day (depending on the infrastructure density). Although aircraft systems are less sensitive than other systems, some aircraft are able to cover large geographic regions rather than targeting only specific sites. This makes it possible to survey entire landscapes for large methane sources that may not otherwise be detected by targeted, site-specific inspections.

***Unmanned Aerial Vehicles (UAVs).***[670] Like manned aircraft, UAVs (also known as drones) are not restricted to roads and can complement close-range methods by reaching dangerous or inaccessible places. Some UAV systems use point measurement technologies that directly measure methane concentrations. These point measurement UAVs are often more sensitive than aircraft techniques because of their ability to fly closer to the methane source.

The primary limitations for this technology are weather, the distance from the operator, and the relatively short flight times of a few hours (at most). The minimum detection limits for UAVs are in the component-to-equipment-level range of spatial resolution. This technology is readily available and has undergone multiple controlled release tests to verify performance metrics.

***Mobile Ground Labs (MGLs).***[671] MGLs are defined as any stationary or mobile ground-based vehicle (car, truck, van, ATV, etc.) equipped with a methane sensor and a GPS. Typically, MGLs will also measure environmental conditions, especially wind speed, wind direction, temperature, and humidity. MGLs can take an active or passive approach to surveying. The active approach entails MGLs driving a predetermined route along the infrastructure to be monitored, while the passive approach entails mounting sensing equipment on vehicles performing unrelated tasks, like delivery trucks.[672]

***Continuous.***[673] Fixed and continuous monitoring technologies can be divided into active and passive categories. Active continuous monitors regularly scan an entire site or use a laser detector to monitor a large area of the site for emissions. Tower-based systems provide even greater coverage and can scan multiple sites from a single location. These systems can usually be deployed in smaller numbers per site. Passive continuous monitors use point sensors to monitor a single location at the site. For passive sensors to detect a leak, the emission plume must be carried via the

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[670] *Id.*
[671] *Id.*
[672] *Id.*
[673] *Id.*

wind to the location of the sensor; therefore, these kinds of sensors must be deployed in larger numbers.

***Satellites.***[674] Many methane-sensing satellites currently exist, and still more are in development; these systems are diverse in form and function. Many have very high minimum detection limits and therefore are better suited to detect large plumes and super-emitters rather than to pinpoint emission sources. However, proposed satellites should offer improved sensitivity and thus afford greater precision in locating emission sources.[675]

Minimum detection limits of satellites has been estimated to be between 1,000 and 7,100 kg $CH_4$/hr.[676] GHGSat has claimed facility-scale detection limits as low as 100 kg/h, but these have not yet been independently verified.[677] Independent efforts using satellites to monitor for super-emitters around the world will help reduce emissions and hold companies accountable. A planned initiative by Carbon Mapper and EDF (MethaneSAT) will provide independent coverage and accountability for regions and producers prone to large methane emission events. Data from these initiatives may be useful in a community monitoring program, which is discussed in greater detail below.

c. Structure and Standard Design

We support EPA providing an alternative compliance pathway that allows frequent, broad-based monitoring using advanced technologies like aerial surveys or continuous monitoring. This approach represents an effective method for detecting large, potentially intermittent sources of emissions that may be missed during less frequent component-level ground surveys. Still, a large portion of emissions originate from smaller fugitive leaks that are currently best detected through ground-based monitoring, like OGI. Regular OGI and repairs are a proven method for reducing emissions and ensuring that sites are well maintained, reducing potential for super-emitters.[678] It is therefore imperative that advanced approaches are layered with component-level OGI requirements.[679] We strongly support EPA's proposal to require at least annual OGI in addition to

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[674] *Id.*
[675] *See, e.g.*, EDF, *MethaneSAT*, https://www.methanesat.org/.
[676] Highwood 2022.
[677] *Id.*
[678] 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/; Ravikumar et al., Repeated leak detection and repair surveys reduce methane emissions over scale of years, 15 Env. Research Letters 034029 (2020), https://iopscience.iop.org/article/10.1088/1748-9326/ab6ae1/pdf.
[679] EPA's fenceline monitoring requirements for refineries provide a useful example of a layered fugitive monitoring approach. Fenceline monitoring standards were adopted to augment traditional LDAR at refineries and improve the management of fugitive emissions. *See* Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards, 80 Fed. Reg. 75,178 (Dec. 1, 2015) [hereinafter Refinery Standards]; *see also* EPA, *National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries Background Information for Final Amendments: Summary of Public Comments and Responses* at 242 (Sept. 2015), https://www.epa.gov/sites/default/files/2018-07/documents/epa-hq-oar-2010-0682-0802.pdf [hereinafter Refineries RTC] ("The goal of the fenceline monitoring program is to improve the management of fugitive emissions by identifying emission sources quickly and reducing these emissions through early detection and repair."); *id.* at 168

advanced monitoring and believe it is well justified by the scientific evidence documenting the nature of oil and gas methane emissions and studies of equivalence and effectiveness of methane detection technologies.

By incorporating a flexible alternative—which may be more cost-effective for many operators and is likely to become less expensive over time—EPA can support innovative new approaches that will allow LDAR and methane mitigation markets to grow and become more efficient. EPA can also set parameters that achieve reductions equivalent to or greater than OGI in a manner that can further spur development of new technologies. Building in this flexibility will ensure that new technologies can qualify for regulatory use and will allow companies to innovate around clear parameters. A strong OGI-based BSER that rests on longstanding analytical methods and relies on proven technologies and approaches provides a clear pathway for compliance and helps to ensure any approved alternative is rigorous and can achieve equivalent or better reductions.

Our discussion in this section assumes as a predicate key improvements in the OGI program as discussed in Part IV.A.2 above. As proposed by EPA, the advanced monitoring alternative requires annual OGI at all sites, regardless of PTE. This means EPA's proposed alternative is more comprehensive and is likely to achieve greater emission reductions, at least at smaller sites, than the BSER and would apply to many more sites. EPA must ensure that the BSER is no less protective than the alternative, and should therefore strengthen the OGI program to remove any disparities in the stringency or coverage of the two potential approaches.[680]

EPA should allow companies to use advanced monitoring technology as an alternative to OGI only when equivalent emission reductions can be demonstrated across a range of emission distributions. To do so, EPA could establish a framework that includes several pre-approved alternatives reflecting different combinations of detection threshold, frequency, regular OGI inspections, and OGI follow-up requirements. Critically, this framework should center on emission reductions, and need not necessarily reflect technologies or practices that are already "in actual routine use somewhere,"[681] (although many are) so long as they are not "purely theoretical or experimental" or "based on a 'crystal ball' inquiry." As discussed earlier in these comments, the Clean Air Act is a technology forcing statute,[682] and section 111 "looks toward what may fairly be projected for the regulatory future, rather than the state of the art at present."[683] EPA could thus design frameworks that accommodate reasonably anticipated improvements in detection capabilities, rather than the limitations of currently in-use technologies. Alongside this preapproved framework, EPA could also consider allowing for submission of alternatives that may have more limited applicability (for instance, in higher emitting basins like the Permian) for specific approval.

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("Fenceline monitoring will . . . allow corrective action measures to occur more rapidly than would happen if a source relied solely on the traditional infrequent monitoring and inspection methods, such as those associated with periodic Method 21 LDAR requirements.").

[680] *See, e.g.*, OOOOa TSD at 56-57 (comparing Method 21 effectiveness at 500 and 10,000 ppm and finalizing 500 ppm as alternative in order to achieve reductions equal to or greater than OGI BSER).

[681] *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973).

[682] *Union Elec. Co. v. EPA*, 427 U.S. 246, 257 (1976).

[683] *Portland Cement Ass'n*, 486 F.2d at 391.

With available methods for comparing emission reductions across different LDAR approaches, EPA need not foreclose the use of new and existing technologies that can effectively reduce emissions. However, EPA must only allow technologies that can be proven to satisfy rigorous parameters and achieve the same or greater emission reductions under a variety of scenarios. To ensure equivalent emission reductions, EPA could finalize multiple approved alternatives by evaluating monitoring frequency and detection capabilities—meaning that technologies with better detection capabilities could be used less frequently and those with higher detection limits could be used more frequently. Equivalence is discussed in more detail below.

For large emission events detected through screening, operators should be required to immediately report to a publicly-accessible database any detected emissions, and additionally, report when the repair is complete. As EPA has recognized, super-emitters should not occur at well designed and well maintained sites. Mitigating super-emitters, while extremely important, is the bare-minimum that EPA should seek to achieve through the LDAR program. If a super-emitter is detected, the operator should be required to submit supporting documentation and explain the likely cause. Operators who could prove the emissions resulted from a permissible event, like a scheduled blowdown, would not have to undertake additional action. However, where the cause of the emissions is unknown, or where multiple events have been detected at the same source or from the same operator, EPA should require a full engineering analysis.

Though we support alternative framework as set forth by EPA, there are also various other ways in which the LDAR program could be structured within the Clean Air Act framework—including layered approaches and advanced monitoring for compliance assurance. Section 114 of the Clean Air Act grants EPA authority to require screening with advanced technologies for compliance assurance purposes. Under section 114(a)(3), EPA "may require any person who owns or operates any emission source . . . to install, use, and maintain . . . monitoring equipment" and "may . . . require enhanced monitoring and submission of compliance certifications." For major sources, EPA is statutorily required to promulgate enhanced compliance assurance monitoring standards,[684] as it has done in the past.[685] Requiring enhanced monitoring for oil and gas sources would be a well-justified use of EPA's discretion because of the severe and widespread problem of fugitive emissions in this sector. Under this alternate approach, EPA could designate OGI as the BSER for fugitive emissions and require advanced screening at all sites periodically for compliance assurance purposes.

As EPA has recognized, a well-maintained site that is following the work practice standards included in the proposed rulemaking (and as strengthened in the ways described in these comments) should not experience super-emitter events.[686] Nonetheless, these large emission events occur frequently across the industry–including at sites owned by major oil and gas

[684] 42 U.S.C. § 7414(a)(3) ("The Administrator shall in the case of any person which is the owner or operator of a major stationary source, and may, in the case of any other person, require enhanced monitoring and submission of compliance certifications.").
[685] *See, e.g.*, Compliance Assurance Monitoring, 62 Fed. Reg. 54,900 (Oct. 22, 1997).
[686] *See* Refinery Standards at 75,190 (explaining that the fenceline monitoring pollutant level that triggered corrective action "was consistent with the emissions projected from fugitive sources compliant with the provisions of the . . . standards").

companies.[687] Using advanced methods to periodically screen for super-emitter events would allow EPA to ensure compliance with the underlying work practice standards and could be used to prevent operators experiencing super-emitters from certifying compliance in those instances.

As a section 114 requirement, advanced monitoring would create further incentives for operators to comply with the work practice standards and take preventative measures against abnormal process emissions. It would also help ensure that reported emissions and inventories are accurate.[688] Furthermore, operators could pool resources and hire a single LDAR contractor to conduct aerial surveys across an entire basin.[689] This is a low-cost solution ($100-200/site) for ensuring compliance and allowing for quick detection and mitigation of large emission events. Accordingly, we encourage EPA to consider how the compliance assurance benefits of these technologies may be integrated into EPA's proposal in a manner that helps to further support emission reductions.

d. Equivalence: Frequency and Detection Capability

To determine allowable alternatives, EPA should evaluate approaches by detection threshold and frequency to determine if these different technologies achieve equivalent emission reductions as EPA's BSER. Based on modeling results, we believe that EPA's proposed alternative of bimonthly screening using advanced technologies with a minimum detection threshold of 10 kg/hr and an annual OGI survey likely reflects the minimum acceptable standards for monitoring frequency and detection capabilities. EPA should therefore consider alternative approaches involving more frequent screening and technologies with more granular detection capabilities. Another option would be for EPA to increase the required frequency of OGI surveys for operators that use advanced technologies with higher detection limits. There are readily available simulation models that EPA can use to generate a presumptive framework for allowable technologies, including ones that evaluate detection capabilities, required screening frequencies, and the necessary work practices when emissions are detected.[690]

EPA's analytical framework for evaluating emission reductions from OGI tends to understate and creates difficulties when comparing to emission reductions achieved by advanced methods. The OGI effectiveness assumptions are generated using an emission profile and baseline emissions assumption that *do not include* well-documented, large, intermittent emission events. However, advanced methods often derive most of their effectiveness from their ability to quickly detect these large events which can then be promptly repaired. As a result, the effectiveness of advanced methods is typically estimated using an emission profile that *includes* large intermittent emission

[687] *See* Permian Methane Analysis Project, *Operator Emissions*, https://data.permianmap.org/pages/operators (showing the ten operators with the highest number of detected emissions with emission rates greater than 1000 kg/hr, including ConocoPhillips, BPX, and Occidental).
[688] Refineries RTC at 13 ("The fenceline monitoring approach was proposed largely to address concerns that emissions, particularly from fugitive sources . . . , are difficult to characterize and studies have shown measured emissions to be many times higher than inventory reported values.").
[689] *See, e.g.*, SPOG Pilot, *Methane Emissions Management Program*, https://www.spogab.com/memp-spog-pilot; Arolytics, *Who We Work With: Governments & Regulators*, https://arolytics.com/who-we-work-with/
[690] Fugitive Emissions Abatement Simulation Tool (FEAST), https://arvindravikumar.com/feast/; LDAR-Sim, https://highwoodemissions.com/ldar-sim/.

events. Therefore the percentage of emissions reduced by OGI cannot be directly compared to percentages reduced by advanced methods in most instances. EPA might resolve this by comparing the quantity of emissions reduced (tonnage) by various approaches or by looking at a range of emission reductions across different potential emission profiles.

The follow-up inspection and repair requirements that apply after emissions are detected are also a critical component of equivalence that should not be overlooked. In general, EPA should require dispatch of repair or follow-up crews anytime emissions are detected with any technology. If a technology can pinpoint the emission source without OGI follow-up, then a repair crew should be dispatched shortly after detection. EPA should also require shorter repair timelines for emissions detected via aerial screenings. Most events detected by an aerial survey will be significant and should be stopped as quickly as possible. After an OGI follow-up, EPA should tier repair timelines to the type of leak (e.g., open thief hatch) in order to stop major emission events. To be most effective, EPA should require screenings to be spaced appropriately (by at least 30 days in the case of bimonthly screening), and should clarify this requirement in the final rule. In addition, some new advanced technologies can quantify leaks, and EPA should consider how quantification could be incorporated into the advanced framework in a manner designed to ensure the largest leaks are fixed most expeditiously.

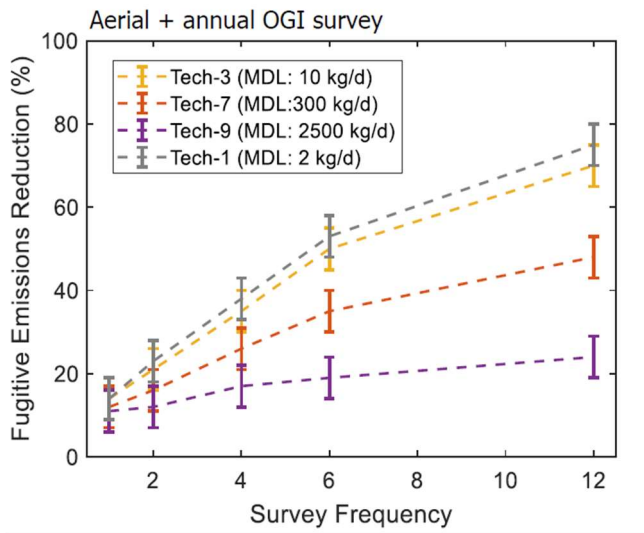
As proposed, only technologies with 10 kg/hr detection capabilities can be used, which potentially excludes some effective and available options.[691] To achieve the same level of emission reductions as the primary alternative standard EPA finalizes, EPA should evaluate the equivalence of screening using lower detection limits as well as the impacts of raising the detection limit and increasing the frequency or adding additional OGI surveys. If EPA is confident that other approaches could achieve the same level of reductions, it could allow for multiple secondary alternatives. Critically, any technology used in the regulations should be capable of achieving its claimed detection threshold in a wide variety of conditions and should have a proven probability of detection at that level. It should also be effective across basins with different emission profiles. For instance, higher detection threshold technologies may not capture smaller leaks and may be ineffective in basins with fewer large emission events or when surveying smaller sites.

Typically, LDAR effectiveness has been estimated with emissions simulation models such as the Fugitive Emissions Abatement Simulation Tool (FEAST). FEAST combines a stochastic model of methane emissions at upstream oil and gas facilities with a model of LDAR programs to estimate the efficacy and cost of methane mitigation.[692] Probabilistic models like FEAST simulate the generation, detection, and mitigation of emissions to compare the effectiveness of LDAR programs with different technologies and work practices. For scientifically rigorous comparisons, models simulate emissions detection based on independent, controlled-release testing under diverse environmental conditions such as wind speed. These models are sensitive to assumptions such as leak rate distributions and repair effectiveness, so it is critical that models use accurate assumptions

[691] TSD at 12-56.
[692] Kemp & Ravikumar, *New Technologies Can Cost Effectively Reduce Oil and Gas Methane Emissions, but Policies Will Require Careful Design to Establish Mitigation Equivalence*, 55 Env. Sci. Tech. 9140–9149 (2021), https://pubs.acs.org/doi/abs/10.1021/acs.est.1c03071.

that are nationally representative and also test results against different likely emission distributions. EPA can and should use these models to accurately estimate percentage reductions from different technologies at different frequencies, which can inform the parameters EPA selects for permissible alternative approaches. An example of this equivalency modeling is shown below, generated using FEAST.

**Figure 16: Example Equivalence Framework Generated by FEAST**[693]




As shown in this figure, EPA can model the effectiveness of different detection thresholds at various frequencies to target a given level of emission reduction. These models are very sensitive to the underlying emission distribution that is used. Alternative approaches must be capable of achieving equivalent emission reductions across a variety of emission distributions representing various basins. Some approaches might achieve significant reductions in a basin like the Permian where abnormal process emissions are common, but the same approach may not be effective in a basin characterized by smaller routine leaks.

We used FEAST to model aerial technologies at various frequencies using one possible nationally representative emission distribution. Effective representation of methane emissions from upstream facilities requires both activity factors and emission characteristics corresponding to specific oil and gas basins. Assumptions used for our modeling include:

- Activity factors for wells: based on Enervus/Prism data (selected across the US for sites with <100 wells/site; average number of wells/site = 1.2);

- Activity factors for equipment/components: similar to EPA assumptions (addition: tank activity factors of 0.84 tanks/well; no flares included in modeling);

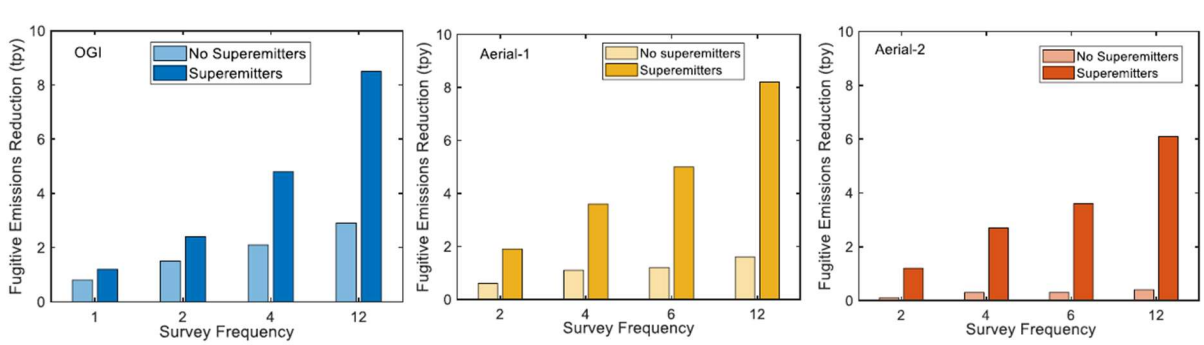
[693] Attachment L (FEAST National Slides).

- Emission factors: 'normal' distribution + 'super-emitter' distribution (normal distribution: aggregation of several bottom-up measurements; 'super-emitter' distribution: Cusworth et al. scaled to tank emissions factors in Rutherford et al.);

- Technology parameters: from published studies of OGI, Bridger, and Kairos (wind dependence explicitly included).[694]

We modeled OGI, Aerial 1 (median detection limit (MDL) (1 m/s) ~ 1 kg/h), and Aerial 2 (MDL (1 m/s) ~ 12 kg/h) at frequencies ranging from annual to monthly using two different emission distributions, one including super-emitters and one without. We also ran the model adding an annual OGI survey to Aerial 1 and Aerial 2 (similar to EPA's proposal). All of the Aerial scenarios also include OGI follow-up requirements similar to EPA's. As would be expected, the effectiveness of OGI is similar to EPA's assumptions when super-emitters are not included in the emission distribution, while Aerial 1 and 2 are less effective given they are less capable of identifying relatively smaller leaks. When super-emitters are accounted for, however, the relative effectiveness of OGI drops and Aerial 1 and 2 increase in effectiveness. One exception is monthly OGI, which remains highly effective because site visits occur regularly enough to catch many super-emitters. These detailed modeling results are included in Attachment L (FEAST National Slides). Below is an additional figure from this FEAST modeling showing absolute site-level reductions of OGI, Aerial 1, and Aerial 2 under both emission distributions.

**Figure 17: Effectiveness Estimates of OGI and Aerial Technologies[695]**




The modeling also finds that adding the annual OGI survey increases the effectiveness of aerial methods (~6% for Aerial 1). When super-emitters are not included in the distribution, the annual OGI survey adds an even greater percentage of emission reductions, even doing most of the work in the case of high detection limit technologies.

In addition to emission reductions, we also modeled cost-effectiveness of these technologies and frequencies using FEAST. We used inputs similar to EPA's and an assumption of $100/survey for aerial methods:

- Annualized capital costs: identical to EPA assumptions;

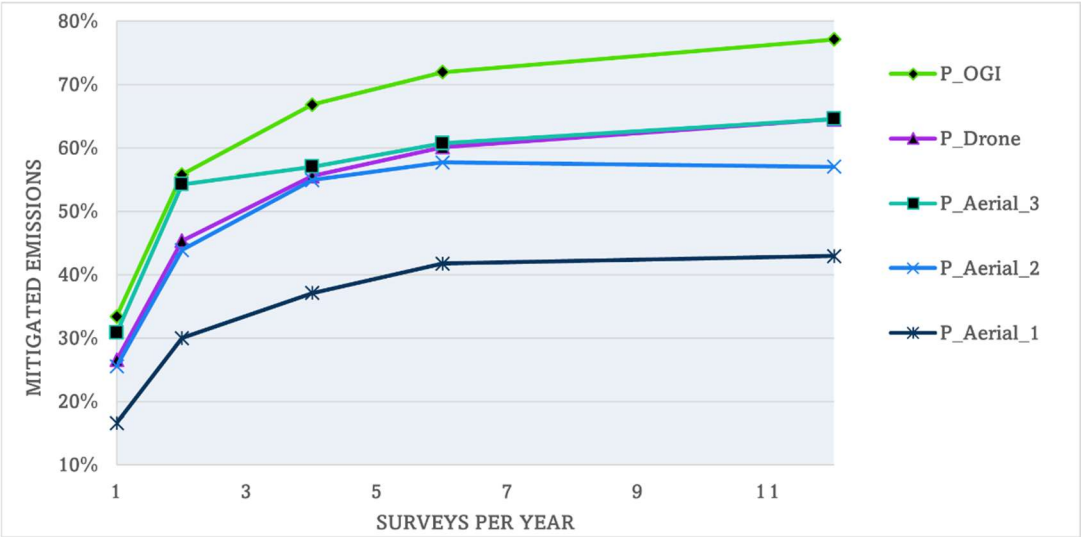
694 *Id.*
695 *Id.*

- Record keeping and reporting costs: identical to EPA assumptions;
- Aerial primary survey costs: $100/site/survey (Kemp et al. 2021);
- Secondary survey technology for aerial systems: OGI;
- Secondary survey cost: $481/site;
- Repair costs: empirical (based on number of repairs per site).

We note that these estimates are likely conservative because they rely on the same inputs as EPA, which we believe are overestimated. Our results show that six to twelve aerial surveys can be conducted per year very cost-effectively ($433-633/per ton of methane reduced).

In addition to FEAST, we conducted cost modeling using LDAR-Sim, in conjunction with survey cost assumptions derived from experts and actual emissions data gathered from seven entities using advanced technologies in the field. These estimates, which are presented fully in a white paper from GTI (Attachment M), show reductions from various advanced technologies coming at mitigation costs as low as few cents per ton of CO2e reduced.[696] GTI's work also estimated the effectiveness of various technologies (Aerial 1 = 20kg/hr MDL, Aerial 2 = 10kg/hr MDL, Aerial 3 = 5kg/hr MDL) using an emission profile representing the Barnett Shale. While these findings are broadly consistent with other estimates, the differences underscore the importance of robust and representative analysis under various sets of assumptions and various emission profiles.

**Figure 18: Estimated Emissions Mitigation at Barnett Production Sites[697]**




As is the case with OGI, in considering emission reductions and cost-effectiveness for advanced technologies, it is important to consider the likelihood and prevalence of super-emitting events. This is because the effectiveness of advanced screening is due in significant part to its ability to quickly detect and stop large emission events. Thus, any analysis that fails to account for these events will greatly underestimate the cost-effectiveness of such a method.

[696] Attachment M (GTI Paper).
[697] *Id.*

As explained above, the assumptions underlying the OGI analysis fail to account for super-emitters, thereby underestimating reductions and overestimating costs per ton reduced. In the proposal, EPA has not accounted for large emission events and appears hesitant to assume these events will occur at each site. EPA could address this (and better account for large emission events) by developing a super-emitter factor that evenly distributes these emissions across sites using reliable statistical methods. In the advanced screening context, EPA could also evaluate costs and emission reductions on a multi-site basis or by creating a model company-defined area for advanced monitoring. Were EPA to assume as its model a 22-site area, for example, it could generate an average emission profile for each site and then assume that a certain representative percentage of those sites would be experiencing a large emission event at any given time.[698]

e. Continuous Monitoring

We support EPA including continuous monitoring technology among the permissible options for compliance and urge the Agency to adopt an alternative LDAR standard that allows for use of continuous monitoring. Continuous monitors, if operated in a rigorous manner with effective follow-up work-practices, have the potential to reduce emissions even further than periodic approaches. Many continuous monitoring systems already meet the parameters EPA has outlined for advanced monitoring: they screen sites at least six times per year at a 10kg/hr detection threshold. In fact, many screen sites far more often than the bimonthly minimum required and have greater detection capabilities. Because of this, EPA can develop an alternative framework for continuous monitoring by making adjustments to account for some of the differences and potential concerns EPA has outlined with respect to continuous monitoring. EPA may need to develop separate, detailed work practice follow-up requirements for continuous monitoring that are technology-specific, similar to the proposed Appendix K for OGI.[699]

EPA should allow for continuous monitoring approaches with detection limits as low as permissible screening approaches as long as equivalent emission reductions can be demonstrated. Most continuous monitoring approaches must also be paired with some degree of OGI follow-up. Operators should be required to perform a follow-up OGI survey if emissions are detected in excess of predicted, permitted emissions. To minimize false alarms, this would require quantitative measurement technology, continuous emissions modeling, and extensive recordkeeping.

EPA could also develop an alternative program for continuous monitoring that does not require follow-up OGI so long as it satisfies the equivalency requirement. Under this approach, the detection limit of the continuous monitoring technology would need to be lower than 10 kg/hr, but not necessarily as low as OGI. The equivalent detection limit for continuous monitors could be

[698] *See* Refinery Standards at 75,198 (explaining that EPA did not consider the cost of root cause analysis and corrective action that is triggered by exceedances of the fenceline standard because those costs result from non-compliance with the underlying standards); *see also* Refineries RTC at 257 ("One purpose of the fenceline monitoring program is to identify instances where the work practice standards in place are not effectively managing fugitive emissions. Thus, in that instance, a source may not technically be in violation of the [standards], but the evidence indicates that it needs to adjust or modify the work practice standards being implemented to provide better management of emissions.").

[699] *See, e.g.*, Comment from Kuva Systems, Teledyne FLIR, CleanConnect.AI, Honeywell Rebellion (Proposed Alternative Work Practice for C-OGI).

estimated with FEAST or other similar approaches by modeling it as a very high-frequency discrete screening. The operator would need to continuously model the expected emission rate to determine when there are excess emissions, and operators would have a set time to repair detected excess emissions.

EPA seeks comment on how to develop a framework for continuous monitoring that includes: 1) the number of monitors needed and the placement of the monitors; 2) minimum response factor to methane; 3) minimum detection level; 4) frequency of data readings; 5) how to interpret the monitor data to determine what emissions are a detection versus baseline emissions; 6) how to determine allowable emissions versus leaks; 7) the meteorological data criteria; 8) measurement systems data quality indicators; 9) calibration requirements and frequency of calibration checks; 10) how downtime should be handled; and 11) how to handle situations where the source of emissions cannot be identified even when the monitor registers a leak. We address these below and note that many of these are questions also applicable to aerial surveys.

EPA can develop a framework for continuous monitoring that tracks our suggestions for the advanced monitoring alternative and ensures at least equivalent emission reductions. If EPA targets a 90% reduction, for example, it can work backwards to determine the (a) detection capabilities, (b) frequency of screening, and (c) follow up work practices that together would achieve this goal. To ensure a technology can reliably detect at a given threshold like 10kg/hr, EPA will have to consider at least five parameters: distance from the source, probability of detection, frequency of detection, wind speed, and temperature/atmospheric-stability class. EPA will also have to evaluate the follow-up work practices associated with detections to ensure a certain reduction target is met. For example, emissions detected by a screening technology that is only capable of 100 kg/hr will be very large, may require repair on short timelines to achieve significant reductions (and in many cases may not be able to show equivalency regardless of repair speed). In most screening approaches, there will also be challenges in determining fugitive emissions versus allowable high emission events and situations where emissions cannot be pinpointed or have disappeared since being detected by screening.

For continuous monitoring, EPA can slightly modify the same framework evaluating detection capabilities, frequency of screening, and follow-up work practices. For continuous monitoring, sensor placement is critical for ensuring that each emission source at the site can be reliably screened at the required detection threshold and frequency. To ensure this, EPA can set minimum requirements for sensor placement, probability of detection, frequency of screening, and other operating parameters.

When considering the appropriate sensor placement, EPA should ensure that every possible source of fugitive emissions is within the reliable range of a sensor and screened the appropriate number of times. Placement of continuous sensors should be required so that the combination of factors above (especially wind and weather, detection probability, and distance) will allow emissions to be reliably detected from any equipment on the site for every period required at the given detection threshold (i.e. bimonthly at 10kg/hr). EPA can create a model for determining proper sensor placement, as it has for refineries fenceline monitoring. In most cases, we anticipate sensors would

be placed close to the largest emission sources, but EPA should also ensure any equipment located farther away can be reliably screened. At larger sites, and depending on technology, this may require multiple sensors to ensure adequate coverage. By contrast, tower-based solutions may be able to reliably screen multiple sites with a single sensor. Sensors must not only be within a horizontal range of emission sources, but must also be able to detect all emission sources vertically.

With continuous monitoring solutions, the follow-up work practices are extremely important. It is critical to clearly define which emissions will require follow-up and which will not. Otherwise, there is a significant risk that operators will be alerted to emissions but determine they do not need to be fixed or cannot be fixed. This problem also exists with other LDAR approaches, but is more pronounced with continuous monitoring where emissions will be more frequently detected. With the potential to be alerted to a wide variety of emission events, absent rigorous protocols, operators may be more likely to avoid following up on each event and will be incentivized to view it as part of normal operations to avoid OGI follow-up costs. EPA must therefore very clearly define the events that require inspection and repair. This might be done by clearly defining the range of the site's baseline emissions. Above the range, there would be a presumption of an abnormality and, unless the operator could prove with records that it resulted from a permissible event, the operator would be required to conduct a ground survey and repair.

Finally, these recommendations describe how continuous monitors may be integrated into the alternative framework EPA has identified in the proposal. At the same time, we are aware that the capabilities of continuous monitors (as well as other advanced screening technologies) are rapidly improving, and so we encourage EPA to create incentives within its framework that will encourage operators to deploy continuous monitors and other advanced technologies in a manner that is maximally protective, consistent with these technological advances. For instance, the agency might consider how approaches that exceed its required standards have implications for community monitoring (discussed below), subpart W reporting, and potentially other related areas.

#### 4. *Community and Third-party Monitoring*

In recent years, methane monitoring technologies have decreased in cost and become widely available. Methane detection is now done by a wide range of individuals and groups, and is not used only to comply with regulatory requirements. Scientists, non-governmental organizations, methane mitigation companies, and individual citizens all routinely monitor for methane leaks from oil and gas operations. These community groups may operate on budgets much more limited than oil and gas companies but also have strong incentives to find and report large leaks. In fact, individuals residing near oil and gas operations are among the most incentivized to find and report those leaks. Already, this community monitoring has generated a wealth of data and observations that can be used by EPA to improve climate and health outcomes as well as help industry to reduce emissions and capture otherwise lost product.[700]

Joint Environmental Commenters support EPA's proposal to develop a community monitoring program where citizen groups and other third parties could make emissions data available to EPA,

[700] *See* Part IV.A.1 (summarizing ten years of methane detection data and science).

owners and operators, and the general public, and which EPA could use to help support further emission reductions as appropriate. Such a program would help achieve greater emission reductions, while fostering operator accountability and building the trust of frontline communities. EPA has ample authority to solicit and rely on third-party data in implementing section 111. Below we explain a legal basis within the Clean Air Act for this type of program, and the details of how such a program should be designed.

EPA has broad authority under sections 113 and 114 of the Clean Air Act to accept monitoring data from third parties and use that data to inform obligations of regulated parties. Section 114 gives EPA broad information gathering authority for the purpose of "developing or assisting in the development of any implementation plan" under section 111(d) and "any standard of performance" under section 111(b), as well as for the purpose "of determining whether any person is in violation of any such standard or any requirement of such a plan."[701] Section 113 gives EPA civil enforcement authority "whenever, on the basis of *any available information*, the Administrator finds that such person" violated "a requirement or prohibition of any rule, order, waiver, permit, or plan promulgated, issued, or approved under" the Clean Air Act.[702] These sections broadly authorize EPA to accept third-party monitoring data and use that data to inform regulatory duties.

Under section 114(a)(1),

> the Administrator may require *any person* who owns or operates any emission source, who manufactures emission control equipment or process equipment, *who the Administrator believes may have information necessary for the purposes set forth in this subsection,* or who is subject to any requirement of this chapter . . . on a one-time, periodic or continuous basis to—
>
> > (A) establish and maintain such records;
> >
> > (B) make such reports;
> >
> > (C) *install, use, and maintain such monitoring equipment*, and use such audit procedures, or methods;
> >
> > (D) sample such emissions . . . ;
> >
> > (E) keep records on control equipment parameters, production variables or other indirect data when direct monitoring of emissions is impractical;
> >
> > (F) submit compliance certifications in accordance with subsection (a)(3); and
> >
> > (G) *provide such other information as the Administrator may reasonably require*[.][703]

[701] 42 U.S.C. § 7414(a).
[702] 42 U.S.C. § 7413(d)(1) (emphasis added).
[703] 42 U.S.C. § 7414(a)(1) (emphasis added).

This provision authorizes EPA to accept, or even (in circumstances not relevant here) require, "any person" to provide EPA with emissions data that may be helpful in "determining whether [such] person is in violation of any such standard or any requirement of such a plan" promulgated under section 111. The authority to require any person to submit emissions data necessarily includes the authority to accept emissions data from any person. And section 114(c) requires that "[a]ny records, reports or information obtained under subsection (a) *shall be available to the public*, except that upon a showing satisfactory to the Administrator by any person that records, reports, or information, or particular part thereof, (*other than emission data*)" are protected trade secrets.[704]

This clear authority to accept, use, and publicize monitoring data from "any person" is further confirmed by EPA's prior interpretations set forth in the Compliance Assurance Monitoring (CAM)[705] and the Credible Evidence Revisions (CER)[706] rules. In promulgating the CAM rule, which requires monitoring for compliance assurance purposes at major sources, EPA relied on both its mandate to "require enhanced monitoring" at major sources under section 114(a)(3) and also its broad information-gathering authority under section 114(a)(1). In CAM, EPA also set out corrective action obligations that were triggered upon detecting an exceedance and required the operator to restore the source to normal operations as "expeditiously as practicable."[707]

In promulgating the CER rule, which clarifies that non-reference test data can be used by EPA, states, and citizens to determine compliance and bring enforcement actions, EPA relied on its "long-standing authority under the Act, and on amplified authority provided by the 1990 CAA Amendments . . . authorizing EPA to bring an administrative, civil or criminal enforcement action 'on the basis of any information available to the Administrator.'"[708] EPA relied on section 113(a), under which "Congress gave EPA clear statutory authority to use any available information—not just from reference tests or other federally promulgated or approved compliance methods—to prove CAA violations."[709]

Certain parties objecting to the CER argued that use of credible evidence by third parties in enforcement actions would be "unconstitutional, unprecedented and unfair," and that "EPA, states or citizen groups would use credible evidence to bring enforcement actions for insignificant violations."[710] In response, EPA rejected those arguments, explaining that "'[f]air warning' jurisprudence holds that regulated sources must have adequate notice identifying 'the standards with which the agency expects parties to conform.'"[711] The CER did not "establish or alter

[704] 42 U.S.C. § 7414(c) (emphasis added).
[705] Compliance Assurance Monitoring, 62 Fed. Reg. 54,900 (Oct. 22, 1997).
[706] Credible Evidence Revisions, 62 Fed. Reg. 8,314 (Feb. 24, 1997).
[707] 62 Fed. Reg. 54,931.
[708] 62 Fed. Reg. 8,314; *see also id.* at 8,315 (" EPA, states and citizens will be able to use credible evidence to assess a source's compliance status and respond to noncompliance. This will help ensure that the government and citizens alike can respond to sources that are not complying with air pollutant emission standards on an ongoing basis, thus furthering the protection of public health and the environment.").
[709] *Id.*
[710] 62 Fed. Reg. 8,317.
[711] *Id.* (citing *General Electric Co. v. EPA*, 53 F.3d 1324, 1329 (D.C. Cir. 1995))

standards with which sources regulated under the CAA must comply," but rather "only concern[ed] the evidence that can be used to prove violations of a standard" and evidentiary rules would govern admissibility in any proceeding.[712]

Sections 113 and 114 and EPA's prior interpretations of these authorities clearly illustrate the broad scope of EPA's authority under the CAA which necessarily includes the ability to accept, use, and publicize third-party monitoring data. EPA can establish a community monitoring program where: 1) third parties can report leaks using detection techniques approved by EPA; 2) EPA has the opportunity to review, approve or disapprove the data, and identify the likely responsible operator(s); 3) operators have an opportunity to prove the detected emissions came from a permissible activity or another site; 4) reported emissions are made publicly available in an easy-to-use format on a webpage; and 5) a regulatory consequence (e.g., a duty to investigate) is triggered for the operator, or EPA otherwise uses the data in some way. Below, we demonstrate how the CAA necessarily supports each of these five steps.

***Detecting and Reporting.*** Third parties can and already do monitor for methane emissions from oil and gas operations. Many detection technologies currently in use by citizen groups do not require site access and do not implicate any safety or other concerns.[713] For example, scientists studying methane emissions routinely monitor sites using handheld infrared cameras or cameras mounted on vehicles, drones, and planes. As noted above, section 114(a)(1) clearly authorizes EPA to accept at any time "information necessary" from "any person . . . [who] may have [such] information" for the purposes of both developing regulatory standards and determining compliance with those standards.[714] This information includes emission monitoring records, reports, samples, and "any other information." Section 114(a)(1)(C) further authorizes EPA to set parameters for monitoring methods and data, including, for example, minimum detection capabilities.

EPA should allow community groups and other third parties to report methane monitoring data for use in the regulatory scheme. The wealth of community generated monitoring data can be utilized by EPA to help ensure compliance with regulations, allow for timely mitigation of leaks, and inform future regulations and policies to further reduce emissions. EPA has well established

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[712] *Id.* ("Credible evidence is far from a new concept in judicial and administrative actions. In private lawsuits such as contract disputes, and in governmental and citizen enforcement actions brought under environmental laws other than the CAA, litigants can and do use a wide variety of information to prove their claims, or to refute the claims of opposing parties. In all these lawsuits, the judge acts as the final, independent arbitrator of what constitutes credible and admissible evidence.").

[713] *See Dow Chem. Co. v. United States*, 476 U.S. 227, 234 (1986) ("Section 114(a), however, appears to expand, not restrict, EPA's general powers to investigate. . . There is no claim that EPA is prohibited from taking photographs from a ground-level location accessible to the general public. EPA, as a regulatory and enforcement agency, needs no explicit statutory provision to employ methods of observation commonly available to the public at large: we hold that the use of aerial observation and photography is within EPA's statutory authority.")

[714] Issues related to section 114's use of "authorized representative" are not implicated here. Third parties would not be acting as an authorized representative of EPA, but rather fall into the category of "any person who . . . may have information necessary for the purposes" of section 114(a). *Cf. United States v. Stauffer Chem. Co.*, 684 F.2d 1174, 1181 (6th Cir. 1982).

frameworks for verifying instrument accuracy[715] and defining leak thresholds,[716] and has in this rulemaking expressed its intent to develop a framework for evaluating the efficacy of alternative and advanced technologies. EPA should require that community-reported data conform to established or newly developed frameworks and, at a minimum, accept any reported emissions information that conforms to the requirements of the LDAR program. EPA should also consider how to enable acceptance of data from less sophisticated monitoring systems that may be used by community groups, such as VOC monitors. Because third parties and community members are unlikely to have physical access to facilities, monitoring is likely to take place from a distance, and consequently, any emissions detection is likely to be more significant. Finally, EPA should set up a webpage that allows for easy reporting.

***Review and Approval.*** Upon accepting emission data from third parties, EPA has authority to review the veracity of the data and approve or disapprove of its legitimacy. EPA can establish standards for third-party data gathering and reporting that must be met in order for the data to trigger regulatory obligations. EPA could also simultaneously notify the responsible operator who could take immediate voluntary action to stop leaks. Section 114(a)(2) authorizes EPA to inspect, access, and sample any information submitted under section 114(a)(1), while sections 113(a)(3) and (d)(1) authorize EPA to use "any information available" to determine compliance with regulatory standards. Both these provisions contemplate that EPA will review information and determine how to use that information. This is also consistent with EPA's broad enforcement discretion.[717]

Upon receipt of community generated emission data, submitted according to EPA's pre-determined reliability parameters, EPA should have a short period of time to review and decide whether to act itself on the data. At this stage, EPA may review the data self-verified by the reporter and decide whether to: (1) declare the data invalid for some reason; (2) do nothing and constructively approve the data for the operator to respond; or (3) actively order the operator to do something more than the default response described below. If EPA has taken no action at the end of the time period, the data should be deemed constructively approved and the emission event should be automatically processed, assigned to an operator via a geographic tag submitted as part of the reporting process, and the operator should receive a notification. Given the potential for a large number of submissions and both the public and operator interest in timely fixing leaks, it is important that this process not hinge on EPA acting within a given timeframe. An automatic system for notifications to the operator and the public is therefore essential, and the accuracy of the data can be ensured on the front end (through the technology approval and reporting process) and on the back end (by operators choosing to rebut the community-generated data and prior to EPA taking any further action).

***Operator Response.*** EPA should notify operators of detected emissions and allow them to investigate, fix, or otherwise show the emissions were permissible. Section 113(a)(4) grants the

[715] *See, e.g.*, 40 C.F.R. part 60 Appendix K (proposed), https://www.regulations.gov/document/EPA-HQ-OAR-2021-0317-0079 .
[716] *See, e.g.*, 40 C.F.R. Appendix A-7 to Part 60 (Test Methods 19 through 25E).
[717] *See* 62 Fed. Reg. 8,318 (explaining EPA's enforcement policies and priorities).

regulated party the opportunity to discuss with EPA the order of violation prior to it taking effect. It also states that the order should take into account "the seriousness of the violation and any good faith efforts to comply." This contemplates and is consistent with EPA notifying an operator of an alleged emission event and giving them a reasonable amount of time to confirm and voluntarily fix the problem, should it be determined that one exists.

After leaks have been reported and approved by EPA, operators should be notified and given an opportunity to fix the leak or otherwise claim that it resulted from another site or a permissible event. Operators should not, however, be given the opportunity to question the validity of the data already approved by EPA. These concerns are adequately dealt with in the preceding steps, and opening up this line of rebuttal would undercut the effectiveness of the program and lead to administrative difficulties. An operator choosing to rebut the data as from a different site not under their control could, for example, submit their own monitoring information, records of inspections and repairs, or other evidence that the leak did not occur from their operations. Additionally, unless the operator has documented and can show a permissible high emission event (like a maintenance blowdown) at the time of the reported leak, it should be assumed to be a fugitive emission. Again, the period for rebuttal should be time-limited and not depend on EPA taking any action.

***Publicizing Emissions Data.*** Section 114(c) requires EPA to make available for the public any records, reports, or other information gathered under section 114. It also specifically exempts emission data from any protection as a trade secret or confidential business information. Emission data gathered offsite in a publicly accessible location should not qualify as a trade secret or confidential business information notwithstanding this provision. EPA is therefore statutorily required to make any emission data collected through third-party participants in this program publicly available. This could be done most easily through a publicly accessible online database, searchable by operator name and geographic location.[718]

Upon expiration of the time period, the emission event should be automatically posted on a publicly available EPA webpage. EDF's PermianMAP project contains a useful model that EPA could build from when designing a webpage. At a minimum, the public should be able to search for leaks by geographic location and by operator. This would be an incredibly valuable tool for frontline communities that seek to reduce emissions in their vicinity, improve health outcomes, hold operators to account, and foster transparency and trust of government. Additionally, EPA's approval of the data would give it extra weight for advocates seeking to reduce emissions, much greater than simply generating their own data that has not been subject to the rigor of an EPA approval processes.

***Regulatory Consequences.*** Section 113 authorizes EPA to issue administrative penalties or order parties to comply with regulatory requirements "on the basis of any information available." EPA can therefore rely on qualifying third-party emission data to generate administrative orders requiring operators to fix leaks. It can also use this information as a basis for enforcement actions

[718] *See, e.g.*, PermianMAP, https://www.permianmap.org/.

in the event operators were not in compliance with work practice standards and, response to community information, do not voluntarily comply.

EPA should set out guidance or develop a model plan for how companies would be required to respond to notification of leaks, incorporating the steps discussed above. This could range from a simple requirement to fix the leak, potentially on shorter timelines dependent on magnitude, to a root-cause analysis or engineering evaluation. EPA might also consider requirements for the operator to notify nearby communities and residents of large emission events.

We urge EPA to adopt final regulations that: 1) allow citizens to report leaks using detection techniques approved by EPA; 2) give EPA the opportunity to review, approve or disapprove the data, and determine the responsible operator; 3) give operators an opportunity to fix the leak or otherwise prove the detected emissions came from a permissible activity or another site; 4) make reported emissions publicly available in an easy-to-use format on a webpage; and 5) trigger a regulatory consequence for the operator or otherwise inform further EPA action. Each of the aspects is critical to a rigorous community monitoring program.

### B. Storage Vessels

Storage vessels are a large source of the industry's methane emissions, accounting for nearly 400,000 tons of methane annually according to the GHGI.[719] EPA's proposal includes several important and necessary changes to the requirements for storage vessels. First, we support EPA's decision to regulate methane (and not just VOC) emissions from new storage vessels and to also establish methane standards for existing storage vessels. We also support the amended definition of "storage vessel" that includes tanks batteries, and welcome the clarification on what factors must be met for a "legally and practicably enforceable limit." However, it is important that the standards be strengthened in several ways outlined below, including lowering the thresholds for emissions controls.

#### 1. *Defining Storage Vessel Affected Facilities to Include Tank Batteries Is Reasonable and Necessary.*

Importantly, EPA proposes to redefine a storage vessel affected facility to "include a tank battery" and to define "tank battery" as "a group of storage vessels that are physically adjacent and that receive fluids from the same source (*e.g.*, well, process unit, compressor station, or set of wells, process units, or compressor stations), or which are manifolded together for liquid or vapor transfer."[720] Thus, an operator is subject to the storage vessel requirements if the tank (in the case of an individual tank) or tanks (in the case of a battery) exceeds the 6 tpy VOC PTE applicability threshold. This is a marked improvement over the current regulations, which define storage vessel affected facilities based only on an individual vessel's PTE. The current definition allows for tanks within the same battery to be treated separately, either as an affected facility (and thus subject to

[719] GHGI at 3-102, Table 3-76 (301,338 metric tons from gathering and boosting); Annex 3.6, Table 3.6-1 (25,052 metric tons from gas production); Annex 3.5, Table 3.5-2 (59,407 metric tons from oil production).
[720] 86 Fed. Reg. 63110, 63178.

OOOO) or not (and thus subject to no standard).[721] Another way to put it is that, under the current definition, an operator could have six tanks manifolded together, each of which had a PTE of 5 tpy, and yet none of them would be deemed affected facilities. Under EPA's proposal, the cumulative 30 tpy PTE would easily exceed the 6 tpy PTE applicability threshold, thus subjecting all of those vessels to the requirement to reduce those emissions by 95%. So instead of potentially emitting 30 tpy, the permissible emissions for that battery would be no greater than 1.5 tpy.

2. *Clarifying "Legally and Practicably Enforceable Limits."*

For EPA's storage vessel requirements to work as intended, it is critical that the PTE is calculated as accurately as possible. EPA should consider defining storage vessels as affected based on actual uncontrolled emissions, rather than defining a vessel as an affected facility based on potential to emit after a "legally and practicably enforceable limit" is taken into account. There is a significant difference between actual uncontrolled emissions and EPA's PTE calculation: a tank with uncontrolled actual emissions of 120 tpy VOC, subject to a "legally and practicably enforceable limit" requiring 95% control of emissions, would have a PTE of 6 tpy VOC. However, controls frequently fail: it is well established that storage vessels are often the source of large emission events due to open thief hatches, deterioration of the vessel, failure of control equipment, and many other reasons.[722] EPA should consider adopting Colorado's approach, which relies on actual uncontrolled emissions, rather than PTE.

Should EPA instead retain its PTE approach and allow operators to deduct emissions subject to "legally and practicably enforceable limits" from PTE calculations, it is critical to determine whether, and if so how, a permit limit on a given source's emissions can impose an enforceable and verifiable cap. EPA proposes to define a "legally and practicably enforceable limit" as including each of the following factors:

- a quantitative production limit and quantitative operational limit(s) for the equipment, or quantitative operational limits for the equipment;
- an averaging time period for the production limit in (i) (if a production-based limit is used) that is equal to or less than 30 days;
- established parametric limits for the production and/or operational limit(s) in (i), and where a control device is used to achieve an operational limit, an initial compliance demonstration (*i.e.*, performance test) for the control device that establishes the parametric limits;
- ongoing monitoring of the parametric limits in (iii) that demonstrates continuous compliance with the production and/or operational limit(s) in (i);
- recordkeeping by the owner or operator that demonstrates continuous compliance with the limit(s) in (i-iv); and
- periodic reporting that demonstrates continuous compliance.[723]

[721] 40 C.F.R. § 60.5395a.
[722] *See* Part IV.A.2.c (within the LDAR section of this comment).
[723] 86 Fed. Reg. 63110, 63201-02.

We support using these factors. Without continuous verification of the parameters under which a source is operating or performing, there is nothing to ensure that the emissions are below the limit expressed in the permit. Particularly given the widespread and well-documented emissions issues from tanks, it is important that there is additional support for thresholds articulated in permits.

If a large emission event occurs, it is very likely that the "potential" that is articulated in a permit has been exceeded. Therefore, in order to fully ensure that the potential is represented, EPA should include in its definition of "legally and practicably enforceable limits" a requirement that operators report actual deviations from normal operations for a source. Along with the type of deviation, this actual deviation report should include the date and time that it was discovered, the date and time of the last confirmed normal operation, and the parametric data that accompanied that source during those times in a manner that will allow EPA to determine whether the permit limit was exceeded.

3. *EPA's New Definition of Modification.*

We also support EPA's proposed definition of "modification" for storage vessels. Adding a storage tank to a tank battery is a physical change to a storage vessel affected facility that results in increased emissions. Replacing a storage vessel with one that has a larger volumetric capacity is also a physical change that increases emissions. It is also our understanding that this frequently occurs at facilities that are space-constrained. Rather than clear new land or space for a new storage vessel, operators who need increased storage capacity will choose a taller vessel that fits the same footprint as the one being replaced, thus increasing capacity without taking up more space. Finally, a tank battery that receives increased throughput that results from the refracturing or addition of a well increases its emissions beyond the projected emissions without that operational change. All three are modifications as defined by the Clean Air Act.[724]

Additionally, an operator should be required to reevaluate a storage vessel affected facility's PTE after a modification has occurred. Replacement of a tank indicates that either there was something wrong with the older tank, or that there was a need for more capacity. Similarly, the addition of a tank indicates a need for more capacity. In both instances, the facility is undergoing a physical change that inherently affects its emissions. The PTE for the source in question should be reevaluated, as it should also be whenever increased throughput is set to occur. Even with the same controls, the replacement of a smaller storage vessel with a larger one, or the addition of a new vessel to a battery, can change the potential to emit. Because there are applicability thresholds where a new storage vessel could be unregulated because its PTE is below 6 tpy, an operator should have to demonstrate that the modified facility's PTE is in the same category (affected vs. unaffected) as it was prior to the modification.

4. *The Applicability Threshold for Storage Vessels Should Be Lowered.*

Under EPA's proposal, whether a storage vessel (or a tank battery) is an affected facility depends on whether the vessel or tank battery would exceed the applicability threshold: 6 tpy VOC for new, modified, or reconstructed sources, or 20 tpy methane for existing sources (which EPA estimates

[724] 42 U.S.C. 7411(a)(4).

is equivalent to 91 tpy VOC).[725] Based on what states with heavy oil and gas development have required, or proposed, in their storage vessel requirements, EPA's proposed applicability thresholds are too high and must be lowered. EPA's high thresholds are based on unrealistically high estimates for the costs of emission controls for tanks, compared to the emission control costs estimates from states.

The State of Colorado requires the control of all new and existing tanks with actual uncontrolled emissions of 2 tpy of VOC or more.[726] Much like EPA's proposal, Colorado's applicability threshold is measured on any individual vessel or group of vessels that are manifolded together.[727] Notably, when Colorado lowered its applicability threshold to 2 tpy in 2019, it performed a cost-effectiveness analysis for three different applicability thresholds (2-3 tpy; 3-4 tpy; and 4-6 tpy), looking at four different classes of storage vessels.[728] Colorado found that control of all tanks with actual uncontrolled emissions over 2 tpy was cost-effective in every single class of storage vessel they looked at.[729] Even looking at the lowest threshold of 2-3 tpy, every class of tank was cost-effective to control, as shown below in Figure 19.

**Figure 19: Average control cost ($/ton VOC)**

| Tank Potential Emissions (tpy) | Condensate Tanks | | Crude Oil & Produced Water Tanks | |
|---|---|---|---|---|
| | DMNFR NAA[730] | Rest of State[731] | DMNFR NAA[732] | Rest of State[733] |
| 2–3 | $2,843 | $2,817 | $2,666 | $2,688 |
| 3–4 | $1,966 | $1,969 | $1,982 | $1,938 |
| 4–6 | $1,432 | $1,068 | $1,106 | $923 |

[725] 86 Fed. Reg. 63110, 63178 (Nov. 15, 2021).
[726] 5 Colo. Code Regs. § 1001-9:D.II.C.1.c.
[727] Colorado's rules apply to any storage tank at upstream facilities (for condensate, crude oil, or produced water) with actual uncontrolled emissions above 2 tpy. *Id.* The rules define a "[s]torage [t]ank" as "any fixed roof storage vessel *or series of storage vessels that are manifolded together via liquid line*. Storage tanks may be located at a well production facility or other location." 5 Colo. Code Regs. § 1001-9:D.II.A.40 (emphasis added).
[728] Those are: Condensate tanks in the Denver Metro North Front Range (DMNFR) Nonattainment Area; oil and produced water tanks in DMNFR Nonattainment Area; condensate tanks outside of the DMNFR Nonattainment Area; and oil and produced water tanks outside of the DMNFR Nonattainment Area.
[729] *See* Colo. Dep't Pub. Health & Env't, *Economic Impact Analysis (Final Analysis)*, Regulation No. 7 (Dec. 17-19, 2019), available at https://drive.google.com/file/d/1ZqvuwyhJn1kb237d22vD0MDcxk_ovasP/view.
[730] *Id.* at 8, Table 4.
[731] *Id*. at 14, Table 13.
[732] *Id*. at 10–11, Table 7.
[733] *Id*. at 13, Table 10.

In neighboring Wyoming, any new[734] or existing[735] storage vessels with potential flash emissions exceeding 4 tpy in the Upper Green River Basin Nonattainment Area are required to be controlled by destroying VOC by 98%. This area produced 62% of Wyoming's natural gas as of 2019.[736] Moreover, since at least 2013 Wyoming has required the control of all flash emissions from any new storage vessels located at a new site statewide with more than one well producing any significant amount of associated gas, without any applicability threshold.[737] This requirement was extended to any modified site in the state in 2018.[738]

In Pennsylvania, since 2013 all new storage tanks emitting more than 2.7 tpy of VOC at production sites are required to be controlled.[739] This VOC applicability threshold was extended to new storage vessels at natural gas compressor stations and processing plants in 2018.[740]Additionally, the State of California requires control of new and existing tanks emitting more than 10 metric tpy of methane.[741] That is comparable to EPA's proposed applicability threshold of 20 short tons per year of methane for existing tanks.

Finally, New Mexico is considering regulations that would require the control of new and existing tanks with potential emissions well below EPA's 6 tpy threshold. For new tanks, the applicability threshold would be 2 tpy. For existing tanks, the applicability threshold would be 3 tpy VOC for tanks in multi-tank batteries, and 4 tpy for existing tanks in single tank batteries.[742]

EPA's reasoning for the proposed high control thresholds of 6 tpy for VOC for new and modified tanks and 20 tpy for methane for existing tanks appears to arise from EPA's very high estimate of the costs for of tank controls. EPA estimates that for even the lowest-emitting sites, the annualized cost of a combustor to control tank emissions at a new site is $31,552, and $34,166 for an existing site.[743] These costs are *more than a factor of four* higher than the cost estimates used by Colorado in support of its rulemaking for existing tanks. For example, in 2019 Colorado estimated that the

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[734] Wyoming DEQ (December 2018), *Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance*, page 14. Available at: https://eqc.wyo.gov/Public/ViewPublicDocument.aspx?DocumentId=17100.
[735] *See* 020-8-0002 Wyo. Code R. § 8-6(c)(i)(A) (Upper Green River Basin permit by rule for existing source).
[736] Wyoming State Geological Survey, News Release, *Wyoming Geological Survey Publishes new Oil and Natural Gas Study of the Greater Green River Basin's Subsurface Geology* (April 29, 2021), *available at* https://content.govdelivery.com/accounts/WYSGS/bulletins/2d344b6
[737] See Wyoming DEQ (September 2013), *Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance*, page 6; *See also* December 2018 Guidance, *supra* note 734 at 7 (note definitions of "PAD" facilities on page 75 of 2013 guidance and page 51 of 2018 guidance).
[738] December 2018 Guidance, *supra* note 734 at 7.
[739] Pennsylvania Dept. of Environ. Protection (2018), General Plan Approval And/Or General Operating Permit GP-5A, Section E(1)(b), (c).
[740] Pennsylvania Dept. of Environ. Protection (2018), General Plan Approval And/Or General Operating Permit GP-5, Section E(1)(b).
[741] Cal. Code Reg. tit. 17 § 95668(a)(6), (7).
[742] New Mexico Environment Department, Proposed 20.2.50 NMAC (Jan. 20, 2022 version), at 20.2.50.123(A). Available at: https://www.env.nm.gov/opf/wp-content/uploads/sites/13/2022/01/Attachment-1-NMED-Proposed-Part-20.2.50-January-20-2022-Version.pdf.
[743]*See spreadsheet* "StTanks Control Costs v5.1" (document EPA-HQ-OAR-2021-0317-0039, attachment 20), sheet "New", cell M9, and sheet "Existing," cell M9.

annual cost of a flare used to control tank emissions was $6,487.70.[744] EPA must re-examine its methodology for estimating the costs of controls for tanks and consider lower thresholds for control of new and existing tanks.

### C. Pneumatic Controllers

#### 1. *Summary*

Pneumatic controllers account for a very large share of the oil and gas sector's methane pollution. EPA's 2021 GHGI estimates that in 2019, these devices emitted 700,000 metric tons of methane in petroleum systems and 1.4 million metric tons in natural gas systems, or 45% of all methane emissions from petroleum systems and 22% of all methane emissions from natural gas systems.[745] In this rulemaking, EPA is proposing methane and VOC standards for new and modified pneumatic controllers, and methane guidelines standards for existing pneumatic controllers in all segments of the industry included in the crude oil and natural gas source category (i.e., production,[746] processing, transmission, and storage).[747] In its final rule, EPA should, as proposed, establish the following BSER for pneumatic controllers: all new, modified, and existing pneumatic controllers, including intermittent controllers, should emit zero natural gas, and existing sources should retrofit within two years of the state plan deadline. Additionally, EPA should eliminate its proposed functional need exemption at processing plants. Should the agency finalize a functional need exemption, it should be narrowly tailored and designed to minimize emissions.

Generally, the Joint Commenters strongly support EPA's proposed standards for pneumatic controllers and urge EPA to finalize key components of the requirements as proposed. The standards acknowledge the variety of cost-effective zero-emitting technologies that are available to operators, apply to intermittent controllers, give operators two years (from the submission deadline for state plans) to retrofit existing sources, and do not contain a broad feasibility or functional need exemption across the source category.

However, while EPA's proposed standards are protective, to reflect the *best* system of emission reduction, they should not include a functional need exemption for *any* segment of the oil and gas sector. In its current form, EPA's proposal would grant functional need exemptions for processing plants[748] but not for sources in the production and transmission and storage segments.[749] We strongly support EPA's proposal to not include a functional need exemption for these latter segments, and we urge the agency to similarly eliminate its proposed exemption for the processing segment. If the agency determines it must finalize a functional need exemption for processing plants, it must narrowly tailor the accommodation. The exemption as currently proposed would

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[744] *See supra* note 729 at 5 (Table 1).
[745] 86 Fed. Reg. 63110, 63203 (Nov. 15, 2021); These figures change slightly when the updated emissions factors for controllers used by EPA in this rulemaking are used to calculate national emissions (see below).
[746] The production segment includes ''centralized tank batteries,'' gathering pipelines, gathering and boosting compressor stations, and related components that collect and transport oil, natural gas, and other materials and wastes from wells to refineries or natural gas processing plants. 86 Fed. Reg. 63110, 63128 (Nov. 15, 2021).
[747] 86 Fed. Reg. 63110, 63202, 63208 (Nov. 15, 2021).
[748] 86 Fed. Reg. 63110, 63208 (Nov. 15, 2021).
[749] 86 Fed. Reg. 63110, 63207 (Nov. 15, 2021).

not require processing plant operators to pursue other technologies that would reduce emissions if non-emitting technologies are not feasible. We recommend that EPA require any such operators to first attempt to reduce emissions by at least 95%,[750] with a preference for routing to a process rather than a control device. If that target is still not feasible, operators should then reduce emissions to the greatest extent possible. In these instances, operators should be required to provide a functional need justification in their annual report, including documentation as to (1) why power (either grid-based or solar) is unavailable, (2) where the operator isn't routing to a process or control device or achieving 95% reductions, why they are not doing so, and (3) how the operator plans to minimize emissions from their pneumatic controllers to the maximum extent possible. In any instances where operators utilize continuous-bleed or intermittent-bleed controllers, they should, at a bare minimum, be required to comply with the finalized recordkeeping and LDAR standards recommended in Part IV.A.

In this section of the comment, Joint Commenters will address the following topics: current emissions from pneumatic controllers; EPA's proposal and why it is generally feasible and cost-effective; EPA's legal authority to require zero-emitting controllers; specific zero-emitting technologies that are widely deployable; the importance of covering intermittent controllers in the standard; why broad exemptions aren't necessary and why EPA should eliminate or at least narrowly tailor its functional need accommodation at processing plants; why the Alaska exemption should not be expanded; and state implementation considerations.

### 2. *Current Emissions*

Pneumatic devices at production sites are one of the top three contributors to methane emissions in the oil and gas sector.[751] EPA's most current GHGI estimates that pneumatic controllers emitted 2,088,427 metric tons of methane in 2019.[752] In this rulemaking, EPA has adopted new emissions factors for pneumatic controllers, but as shown in Figure 20 , using activity data from the GHGI and the new emissions factors from this rulemaking show that the national emissions from these devices still approach two million metric tons of methane per year.

[750] For example, operators that can't install zero-emitting technology might nonetheless be able to route to a vapor recovery unit or control device, which aren't zero-emitting in accordance with the proposed standard but which reduce emissions by 95%-98%. See TSD 6-16; TSD 9-9.
[751] Attachment N, Carbon Limits, *Zero emission technologies for pneumatic controllers in the USA: Updated applicability and cost effectiveness*, 4 (Nov. 2021) ("Carbon Limits 2021"), https://www.catf.us/resource/zero-emission-technologies-for-pneumatic-controllers-in-the-usa/
[752] GHGI 2021 at 3-82.

**Figure 20: Emissions for Pneumatic Controllers by Segment and Type of Controller**[753]

| Emissions Estimates (in metric tons) and Equipment Counts | | Type of Controller | | | |
|---|---|---|---|---|---|
| | | Low-Bleed | Intermittent-Bleed | High-Bleed | Total |
| Production Segment - Well Pads | Methane Emissions (%) | 164,207 (9.6%) | 1,479,947 (86.3%) | 70,551 (4.1%) | 1,714,705 |
| | Number of Controllers (%) | 421,043 (27.8%) | 1,064,710 (70.3%) | 28,448 (1.9%) | 1,514,201 |
| Production Segment - Gathering and Boosting Stations | Methane Emissions (%) | 14,865 (8.8%%) | 142,106 (84.3%) | 11,626 (6.9%%) | 168,597 |
| | Number of Controllers (%) | 38,114 (26.3%) | 102,235 (70.5%) | 4,688 (3.2%) | 145,037 |
| Transmission and Storage Segment | Methane Emissions (%) | 1,400 (2.3%) | 30,900 (50.6%) | 28,700 (47.0%) | 61,000 |
| | Number of Controllers (%) | 6,434 (6.5%) | 82,040 (83.3%) | 10,027 (10.2%) | 98,501 |
| Total | Methane Emissions | | | | 1,944,302 |

As summarized in Figure 21 emissions predominantly come from oil and natural gas production well facilities, with a smaller but still substantial amount coming from natural gas gathering and boosting stations, and transmission and storage facilities.

**Figure 21: Emissions for Pneumatic Controllers by Oil and Gas Industry Segment**

| | CH4 Emissions (kt) |
|---|---|
| Gas Production Segment - Well Pads | 1,046.1 |
| Gas Production Segment- Gathering and Boosting | 168.6 |
| Gas Transmission and Storage Segments | 61.0 |
| Gas Processing Segment | 2.1 |
| Oil Production Segment | 668.6 |

<u>Data for emissions from specific types of pneumatic controllers</u>

According to the EPA, of the combined methane emissions from pneumatic controllers in the petroleum system and natural gas system production segments, emissions from intermittent vent

[753] For this table and the two that follow, emissions figures in the production segment are calculated using equipment counts from 2021 GHGI data and individual controller emissions from Table 8-3 of the TSD, which come from Tupper, Paul, "API Field Measurement Study: Pneumatic Controllers EPA Stakeholder Workshop on Oil and Gas" (November 7, 2019). For the processing segment and transmission and storage segment, figures are based on Annex 36 Table 3.6-1 in the 2021 GHGI.

controllers make up over 85 percent of the total.[754] Additionally, data from the GHGI and TSD provide information on the distribution of emissions by type of pneumatic controller and show that the great majority of reported emissions from oil and natural gas pneumatic controllers across the source category originate from intermittent-bleed devices (Figure 22).

**Figure 22: Emissions by Type of Pneumatic Controller**

| Emissions by Controller Type (mt methane) | Gas Production | Oil Production | Gathering and Boosting | Gas Transmission | Gas Storage | Total |
|---|---|---|---|---|---|---|
| Low Bleed Controllers | 81,431 | 82,776 | 14,865 | 901 | 516 | 180,489 |
| High Bleed Controllers | 42,309 | 28,242 | 11,626 | 11,502 | 17,187 | 110,866 |
| Intermittent Bleed Controllers | 922,385 | 557,564 | 142,106 | 24,543 | 6,365 | 1,652,963 |
| Total Controllers | 1,046,125 | 668,582 | 168,597 | 36,946 | 24,068 | 1,944,318 |

Numerous studies report that pneumatic controllers often emit more than their design values indicate. Intermittent controllers are designed to emit only during the actuation cycle for the controller, but in the field, these devices frequently emit between actuations. For example, Luck et al. (2019) reported that 63% of the intermittent controllers observed as part of that study were operating abnormally.[755] Similarly, "low-bleed" continuous pneumatic controllers have also been observed to frequently emit more than they are designed to emit, and it is not uncommon for their emissions to exceed the 6 standard cubic feet per hour standard for "low-bleed" devices. Due to the ubiquity of these types of malfunctions, measures designed to merely *reduce* emissions from pneumatic controllers (such as by requiring that any continuous controller be "low-bleed") have generally proved to be less effective than anticipated. For this reason, EPA's proposed approach to require all devices to be non-emitting is very appropriate.

3. *EPA's Proposed Standards for Pneumatic Controllers are Cost-Effective and Feasible.*

EPA's model plant-based calculations show that the proposed standards are highly cost-effective for operators. EPA calculates that the standards will reduce methane emissions at a cost as low as $370 per ton of methane abated at processing plants (using a multipollutant approach, the cost is as low as $185 per ton of methane).[756] At large production sites, the proposed standards would cost $210 per ton of methane abated before natural gas savings and $120 per ton of methane abated when considering savings (using a multi-pollutant approach).[757] Similarly, at small and medium

[754] Intermittent controllers account for about 86% of emissions when using Figures 20 and 22 which outline EPA estimates, but in the proposal, EPA states it estimates that intermittent controllers constitute 88% of emissions. See 86. Fed. Reg. 63110, 63203 (Nov. 15, 2021). For the sake of simplicity, we arrive at "over 85 percent."
[755] Benjamin Luck et al., *Multiday Measurements of Pneumatic Controller Emissions Reveal the Frequency of Abnormal Emissions Behavior at Natural Gas Gathering Station*s, Environ. Sci. Technol. Letters 6, 348 52 (2019), https://pubs.acs.org/doi/10.1021/acs.estlett.9b00158.
[756] 86 Fed. Reg. 63110, 63208 (Nov. 15, 2021).
[757] 86 Fed. Reg. 63110, 63206 (Nov. 15, 2021).

production sites, EPA calculates that the standards will reduce emissions at a cost of $250-275 per ton of methane abated before savings and $160-$185 per ton of methane abated when considering savings (again using a multipollutant approach).[758] These numbers are an order of magnitude lower than values that EPA has previously found cost-effective–$2,185/ton–as well as the current social cost of methane. Likewise, EPA analysis shows that costs of the standards for pneumatic controllers in the transmission and storage segments are far lower than either of these metrics, and thus easily qualify as cost-effective as well.[759]

Though EPA's analysis shows its proposed standards for pneumatic controllers are cost-effective, our analysis finds that EPA did not accurately calculate costs and that, because EPA's calculations generally *overestimate* the cost of the proposed standards, the standards are even more cost-effective than EPA found. Here, and in more detail in our Pneumatic Controller Cost Calculation Memo[760] and Spreadsheet,[761] we present an analysis to correct and bolster the record on the cost-effectiveness of zero-emitting pneumatic controllers. Some of the corrections we make tend to increase costs, while many others result in lower costs. Addressing these issues, which we summarize below and in the attached memo and spreadsheet, would result in a strengthened record demonstrating the cost-effectiveness of the zero-emitting pneumatic controller requirement across segments. The updates we made are summarized below:

- A new version of the Carbon Limits Zero Bleed Pneumatics Cost Tool[762] has recently been published, with some updates and refinements to the cost methodology. In addition, the costs in the 2021 version of the tool reflect current costs and do not need to be scaled from $2016 to $2019.

- For electric controllers, EPA assumed that capital costs would be the same for both new and existing (retrofit) sites. This is not accurate, because new sites must consider net costs, subtracting out baseline costs. In addition, existing sites may be able to reuse some equipment on-site, which will result in lower costs.

- EPA did not consider maintenance/ongoing costs. Adding in maintenance costs adds to overall costs in some cases, but in many cases it reduces overall costs due to high maintenance costs of the gas-driven pneumatic controller systems that will no longer be used.

- EPA assumes that emissions reductions will be the same for both new and existing sites. This is inaccurate, because the baseline for existing sites includes existing high- bleed pneumatic controllers, while the baseline for new sites should assume that all new continuous-bleed controllers are low-bleed, as required by current regulations.

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[758] 86 Fed. Reg. 63110, 63206 (Nov. 15, 2021).
[759] *See* 86 Fed. Reg. 63110, 63206 (Nov. 15, 2021).
[760] Attachment O, PC Cost Memo.
[761] Attachment P, PC Cost Spreadsheet.
[762] Attachment Q, Carbon Limits Zero Bleed Pneumatics Cost Tool.

- EPA treats costs for production and transmission and storage equivalently. However, there are numerous cases in which the costs will be different due to different emissions factors used in the different segments.

- According to EPA's TSD, it designed the small, medium, and large model plants based on an assessment of production facility size, and it "assumed that well site controller numbers would apply to both production and transmission and storage sites."[763] This assumption is not reasonable for transmission and storage sites, because the average size of these sites is much larger than EPA's "large" model plant. This is relevant because at larger sites, zero-bleed conversion becomes even more cost-effective. As a result, we do not present here the costs of EPA's small, medium, and large model plants for the transmission and storage segment. The size of the large model plant defined by EPA does align closely with the average size of a gathering & boosting station, meaning that EPA's "large" model plant *is* appropriate for estimating costs at gathering and boosting compressor stations.

We summarize costs for all segments and facility types using CATF's updated analysis based on the Carbon Limits Tool and compare them to EPA's costs in Figures 23 and 24. Specifically, CATF's updated analysis shows that costs for the pneumatic controller standards are similar to or lower than that estimated by EPA.

[763] TSD 8-9.

**Figure 23: Comparing EPA and CATF Cost Analyses at Well Production and Gathering and Boosting Sites**

| Vintage | Size | Control Option | Cost Effectiveness $/ton with Savings – Single Pollutant | | | |
|---|---|---|---|---|---|---|
| | | | EPA estimate | | CATF revised estimate[764] | |
| | | | VOC | Methane | VOC | Methane |
| New | Small | Option 2a - Electric | $1,129 | $314 | $399 | $111 |
| | | Option 2b - Electric with solar | $1,316 | $366 | $774 | $215 |
| | Medium | Option 2a - Electric | $963 | $268 | -$179 | -$50 |
| | | Option 2b - Electric with solar | $1,152 | $320 | -$35 | -$10 |
| | Large | Option 2 – compressed air | $863 | $240 | $772 | $215 |
| Existing | Small | Option 2a - Electric | $1,129 | $314 | $59 | $16 |
| | | Option 2b - Electric with solar | $1,316 | $366 | $256 | $71 |
| | Medium | Option 2a - Electric | $963 | $268 | -$101 | -$28 |
| | | Option 2b - Electric with solar | $1,152 | $320 | $17 | $5 |
| | Large | Option 2 – compressed air | $1,369 | $380 | $1,326 | $369 |

[764] CATF estimates presented here represent costs at wet gas sites. Ongoing/maintenance costs for natural gas-driven systems with wet gas can be significant, since constituents of natural gas (especially the raw natural gas used on well pads and at gathering compressor stations) can be chemically incompatible with seals and other components of the controller, and droplets of liquids that form in components using raw natural gas will interfere with the operation of the controller. Carbon Limits notes that these problems can occur with "even slightly wet gas." See Carbon Limits 2021 at 11. Some production sites may handle dry gas; costs for these sites, as documented in the PC Cost Memo and PC Cost Spreadsheet (Attachments O and P), are slightly higher due to lower maintenance costs for the gas-driven controller alternative.

**Figure 24: Comparing EPA and CATF Cost Analyses at Transmission and Storage Compressor Stations**

| Vintage | Size | Control Option | Cost Effectiveness $/ton without Savings[765] – Single Pollutant | | | |
|---|---|---|---|---|---|---|
| | | | EPA estimate | | CATF revised estimate | |
| | | | VOC | Methane | VOC | Methane |
| New | Large* | Option 2 – compressed air | $38,036 | $1,053 | * | * |
| | GHGI Transmission Station | Option 2 – compressed air | NE | NE | $34,686 | $960 |
| | GHGI Storage Station | Option 2 – compressed air | NE | NE | $22,958 | $635 |
| Existing | Large* | Option 2 – compressed air | $50,715 | $1,404 | * | * |
| | GHGI Transmission Station | Option 2 – compressed air | NE | NE | $37,158 | $1,028 |
| | GHGI Storage Station | Option 2 – compressed air | NE | NE | $14,344 | $397 |

*Note: We do not present costs from our analysis using EPA's "large" facility size, because this does not accurately represent the actual average size of transmission and storage facilities. Instead, it is more accurate to consider costs based on the "GHGI Transmission Station" and "GHGI Storage Station" facility sizes for these facilities.

NE: Not Estimated

[765] Costs for compressor stations are presented without accounting for gas savings because in some cases, compressor station operators do not own the gas so will not realize the monetary benefits of reducing gas venting. However, in cases where compressor station operators do own the gas, those operators will be able to comply at even lower costs than those presented here,

Experience also shows that it is very reasonable to require the use of zero-emitting controllers both on and off the grid. Since May 1, 2021, Colorado's oil and gas regulations have required that all new and modified well production sites and natural gas compressor stations use non-emitting pneumatic devices (including intermittent controllers), regardless of grid access.[766] Additionally, operators of existing well production facilities (with the exception of those with low average production per well) and gathering compressor stations must replace or retrofit a portion of their existing pneumatic controllers with non-emitting devices over the next two years. Operators must retrofit a significant portion of their controllers by May 2022, and retrofit an additional portion by May 2023, according to schedules included in the regulation.[767] Notably, these rules were the product of negotiations between industry, environmental organizations, local governments, and the Colorado Dept. of Public Health and Environment. When they were considered by the Colorado Air Quality Control Commission, no party opposed either the prohibition of emitting controllers at new and modified sites or the retrofit requirements.[768] Similarly, California has imposed a zero-emitting continuous controller requirement and, like EPA's proposal, doesn't provide a feasibility exemption. As with Colorado's standards, these requirements have been effectively implemented in the state.

Standards similar to those proposed by EPA have also proven feasible in Canada. In British Columbia, controllers (including intermittent devices) at all new facilities, all existing compressor stations with total installed compression power of 3 megawatts or more, and all existing processing plants must not emit natural gas.[769] In Alberta, any pneumatic instruments installed on or after January 1, 2022 must not emit any natural gas.[770] These standards build on substantial voluntary adoption of non-emitting pneumatics in Canada that occurred before the regulations were adopted: a 2019 study in British Columbia found that of the controllers analyzed, 65% were non-emitting.[771]

Furthermore, several oil and gas operators are already transitioning to zero-emitting pneumatic controllers on their own, without EPA or state regulations. EQT, the largest natural gas producer in the country, with operations in Pennsylvania, West Virginia, and Ohio,[772] is transitioning its

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[766] Section D.III.C.4.a of Colorado Department of Public Health and Environment, "Control of Ozone Via Ozone Precursors and Control of Hydrocarbons Via Oil and Gas Emissions (Emissions of Volatile Organic Compounds and Nitrogen Oxides), Regulation Number 7," (5 CRR 1001-9) (hereinafter "Colorado Regulation Number 7").
[767] *See* D. III.C.4.c(i), D.III.C.4.d(i), and D.III.C.4.c(iv) of Colorado Regulation Number 7.
[768] *See generally* "Parties' Rebuttal Statements" (Feb. 4, 2021) (noting general support for compromise proposal in final written submission of rulemaking hearing), available at https://drive.google.com/drive/folders/1LHvSRVBP89EK9WdRP6dGNOXKou-Fzb9n; *see also* Mark Jaffe, First-in-the-nation rule to slash methane emissions from Colorado emissions from Colorado oil and gas operations relied on compromise, Colo. Sun (Feb. 19, 2021), https://coloradosun.com/2021/02/19/oil-gas-controllers-colorado-rule-methane-emissions/ (noting that the compromise rule was supported by industry trade groups, environmental groups, and more than sixty local governments).
[769] B.C. Reg 282/2010, Oil and Gas Activities Act, Drilling and Production Regulation (amended March 4, 2021), 52.05, available at https://www.bclaws.gov.bc.ca/civix/document/id/crbc/crbc/282_2010
[770] Alberta Energy Regulator, Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting. 8.6.1 Vent Gas Limits for Pneumatic Devices (April 2021), https://static.aer.ca/prd/documents/directives/Directive060.pdf
[771] Cap-Op Energy, British Columbia Oil and Gas Methane Emissions Field Study 2 (2019), available at https://www2.gov.bc.ca/assets/gov/environment/climate-change/ind/reporting-emissions/2019/british_columbia_oil_and_gas_methane_emissions_field_study.pdf
[772] EQT Corporation, *Production*, https://www.eqt.com/operations/production/ (last retrieved Jan. 27, 2022).

fleet of 8,000 pneumatic controllers to zero-emitting devices.[773] The company has committed to completing that process by the end of 2022 and anticipates an over 50% reduction in methane emissions as a result.[774] A Texas operator, Diamondback, plans to transition "nearly all" of its pneumatic controllers to compressed air units over the next four years.[775] ConocoPhillips, which operates across the U.S.,[776] has reported that many of its new sites use compressed air instead of natural gas for pneumatics.[777] Pacific Gas & Electric in California has transitioned all of its high-bleed controllers in the transmission and storage segment to zero-emitting controllers (or reconfigured equipment so that no controller is needed).[778] The broad geographic range of companies transitioning either partially or entirely to zero-emitting pneumatics even in the absence of regulatory pressure demonstrates the feasibility of such a process on a national scale. Indeed, Chevron has said that "improving technology in pneumatic controllers is one of the lowest-cost solutions for reducing methane emissions."[779]

Moreover, recent information suggests the market is well positioned to deliver these zero- emitting alternatives. One recent study by Datu Research identified at least 30 manufacturers that produce alternatives to pneumatic devices or "APDs," which were defined in the report as devices driven by compressed instrument air, electric, and solar.[780] This makes APDs the most prevalent type of methane mitigation technology among firms studied. The voluntary, widespread adoption of zero-emitting technology and multitude of suppliers demonstrates the ability of industry to "achieve" this standard and that the technology is "adequately demonstrated," fully consistent with the statutory requirements of section 111.[781][782]

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[773] EQT Corporation, Pneumatic Device Replacement: Low-Cost Opportunity for Methane Abatement (Jan. 2022), https://eqt.brunnerstage.com/wp-content/uploads/2022/01/Pneumatic-Device-Replacement-FINAL.pdf

[774] *Id.*

[775] Diamondback Energy, 2021 Corporate Sustainability Report at 8 (2021), available at https://www.diamondbackenergy.com/static-files/faf5ab25-5ab5-4404-8c04-c7bd387ae418.

[776] ConocoPhillips, Worldwide Operations and Locations, https://static.conocophillips.com/files/resources/21-0250-l1-q4-2020-worldwide-operations-map.pdf (last retrieved January 27, 2022).

[777] ConocoPhillips, Emissions Reductions Targets https://www.conocophillips.com/sustainability/managing-climate-related-risks/metrics-targets/ghg-target/ (last retrieved January 27, 2022).

[778] EPA, Natural Gas STAR Program, Pacific Gas & Electric Methane Challenge Partner Profile, https://www.epa.gov/natural-gas-star-program/pacific-gas-electric-company-methane-challenge-partner-profile#atsPneuCont (last retrieved January 27, 2022).

[779] Colorado Sun, Colorado regulators target tiny oil field device that's a big contributor to greenhouse gas, ozone pollution, https://coloradosun.com/2021/01/21/oil-gas-pneumatic-controllers-colorado-regulations/ (Jan. 21, 2021)

[780] Datu Research, "Find Measure Fix: Jobs in the U.S. Methane Emissions Mitigation Industry", 16, 42-50, https://www.edf.org/sites/default/files/content/FindMeasureFixReport2021.pdf (2021). While page 16 notes there were 29 firms, an independent count of firms using the table in the appendix shows that number is actually 30.

[781] *See Portland Cement Ass'n,* 486 F.2d at 375 ("Section 111 looks toward what may fairly be projected for the regulated future, rather than the state of the art at present" and therefore the Administrator may determine whether a technology is "adequately demonstrated" based on a "reasonableness" standard); *Essex Chemical Corp.,* 486 F.2d at 433-434) ("An achievable standard is one which is within the realm of the adequately demonstrated system's efficiency and which, while not at a level that is purely theoretical or experimental, need not necessarily be routinely achieved within the industry prior to its adoption.").

[782] Despite the increasingly broad adoption of zero-emitting controllers throughout the industry, there are still many operators that would not choose to transition to zero-emitting technology without regulatory pressure. A strong, nationally applicable standard from EPA is therefore necessary to ensure the universal implementation of this

Because zero-emitting controller technology is widely deployable and cost-effective, and does not require grid power, we strongly support EPA's decision not to provide a broad feasibility or functional need exemption in the proposal. Furthermore, we believe that a functional need exemption for the processing segment is unnecessary and urge EPA not to include it in the final rule. As explained in more detail in sub-section 6, should EPA choose to retain that exemption, we urge the agency to narrowly tailor it by requiring effective secondary control options and by requiring that operators submit functional need justifications in their annual reports.

#### 4. *Multiple Kinds of Zero-Emitting Technologies Are Adequately Demonstrated and Commercially Available for Pneumatic Controllers*

Natural gas-driven pneumatic controllers are used widely in the oil and natural gas industry to control liquid level, temperature, and pressure during the production, processing, transmission, and storage of natural gas and petroleum products. These devices vent methane into the atmosphere and are, according to EPA inventories, the second largest source of methane from the US oil and gas industry. However, there are a variety of alternatives to natural-gas driven controllers that emit zero methane. Since 2016, the availability and deployment of these zero-emitting pneumatic controllers has expanded significantly.[783]

##### a. Electronic Controllers

One zero-emitting technology that is readily available is an electronic controller. Electronic controllers adjust the position of the end-device by sending an electric signal to an electric actuator or positioner (as compared to pneumatic controllers which send a pneumatic signal to a pneumatic actuator or positioner). A motor powers the electric actuator to adjust the control valve to the desired position.[784]

Electronic controllers are engineered by a variety of companies, and the technology continues to advance. One company has installed over 1800 electric actuators at oil and gas sites throughout Western Canada over the past seven years and plans on installing over 1,000 in 2022.[785] As discussed above, electronic controllers are highly cost-effective, reducing methane at an expense that is far lower than levels that EPA has in the past found were cost-effective.[786]

Electronic controllers can be installed at sites using an electric grid connection and at sites that are not connected to the grid by using a generator or solar power, among other options. We discuss these different possibilities in the sections that follow.

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technology and achieve critically needed emission reductions, even in light of the positive shift already occurring within the industry.

[783] Standards of Performance for New Stationary Sources; VOC Fugitive Emission Sources; Petroleum Refineries, 48 Fed. Reg. 279, 287 (proposed Jan. 4, 1983); *see also* Standards of Performance for New Stationary Sources Equipment Leaks of VOC Petroleum Refineries and Synthetic Organic Chemical Manufacturing Industry, 49 Fed. Reg. 22,598 (May 30, 1984) (finalizing closed-purge requirement).

[784] Carbon Limits, Zero emission technologies for pneumatic controllers in the USA: Applicability and cost-effectiveness, 3 (August 2016) ("Carbon Limits 2016").

[785] Tressier, Henri, Managing Partner, Calscan Solutions, Email to Grace Smith, Environmental Defense Fund, January 26, 2022.

[786] *See supra* Figure 23; *See* 86 Fed. Reg. 63110, 63,155 (Nov. 15, 2021) ("EPA finds the cost-effectiveness values up to $1,800/ton of methane reduction to be reasonable").

***With Grid Access***. Grid-connected electronic controllers are a feasible zero-emitting option for operators. A significant number of sites already have access to the grid, and an even larger number can connect a line to the grid. According to EPA's assumptions, all processing plants[787] and 40% of well sites have access to reliable electricity.[788] And in a 2015 survey of companies, 34% of companies in the U.S. reported that all of their gathering compressor stations have grid access and only 7% reported that none of their sites had access,[789] with grid accessibility having likely improved across the industry since 2015.

Operators can install this type of electronic controller system at a low-net cost. Electricity generation nationally has increased significantly since the 2016 rule,[790] resulting in improved electricity availability for oil and gas operators. Additionally, the power required for electronic controllers is decreasing. In fact, the power demand for electronic controllers is lower than for traditional gas-driven controllers.[791] Furthermore, electronic systems have much lower maintenance costs than gas-driven controller systems and are longer lasting,[792] and electronic controllers and actuators can be connected to existing valves at well sites, eliminating the need to replace control valves.[793] Finally, electronic controllers eliminate methane and VOC emissions and thus increase the volume of gas available for sale.[794]

For these reasons, the abatement costs for electronic controllers with grid access have steadily declined over the past 5 years,[795] and will likely continue to decline. The following data points (all based on a multi-pollutant approach) reflect just how remarkably cost-effective this technology is. For EPA's small model production site, abatement costs at existing sites accounting for the value of saved gas is $8/ton of methane for a site with wet gas and $51/ton of methane for a site with dry gas. At new, small production sites, costs are $55/ton of methane for wet gas and $123/ton of methane for dry gas. For EPA's medium model production site, abatement costs at existing sites accounting for the value of saved gas is -$14/ton of methane for a site with wet gas and $29/ton of methane for a site with dry gas. And at new medium production sites, costs are -$25/ton of methane for wet gas and $28/ton of methane for dry gas.[796]

***Without Grid Access – Solar.*** At sites without grid access, electronic controllers can be powered by solar control systems. These systems are approximately as cost-effective as grid-powered electric controllers and are technologically feasible for both new sites and retrofitting existing sites.[797] The following data (all based on a multi-pollutant approach) illustrate this. For EPA's small model production site, abatement costs at existing sites accounting for the value of saved gas

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[787] TSD 2-21.
[788] TSD 2-17.
[789] Alphabet Energy, *On-Site Power: New Options for Wellhead & Gathering Compression*, Natural Gas Star Annual Implementation Workshop, November 18, 2015, https://www.epa.gov/sites/default/files/2016-04/documents/16hjalmarsonpahl.pdf (last accessed January 21, 2022).
[790] Attachment R, EIA Electricity Generation at 3.
[791] WZI, Inc., Review of Oil and Gas Facility Controller Deployment Alternatives in Colorado (Jan. 2021) ("WZI 2021") at 7.
[792] WZI 2021 at 7.
[793] Carbon Limits 2021 at 9.
[794] Carbon Limits 2021 at 15.
[795] Carbon Limits 2021 at 15.
[796] Attachments O and P, PC Cost Memo and PC Cost Spreadsheet.
[797] WZI 2021 at 1-2.

is $36/ton of methane for a site with wet gas and $78/ton of methane for a site with dry gas. At new, small production sites, costs are $108/ton of methane for wet gas and $175/ton of methane for dry gas. For EPA's medium model production site, abatement costs at existing sites accounting for the value of saved gas is $2/ton of methane for a site with wet gas and $45/ton of methane for a site with dry gas. And at new medium production sites, costs are -$5/ton of methane for wet gas and $48/ton of methane for dry gas.[798]

The solar resource is sufficient to power these systems in many geographic locations. Consider, for instance, northern Alberta, where substantial oil and gas development occurs: solar panels generate less power than in lower latitudes, sunlight on a clear day is far weaker than in many parts of the U.S., snowfall is higher and winter cloud cover is much more common, and winter temperatures are much lower (affecting battery capacity). Nevertheless, solar-powered controllers have been reliable for oil and gas companies operating there.[799] Calscan, an Alberta vendor of packages that utilize solar-power and batteries to power electric actuators and instrumentation for zero-emission separators,[800] estimates that they have sold about four hundred of these packages in Canada (mainly in Alberta).[801] Moreover, EIA data demonstrates that the availability of solar power in several regions around the U.S. has increased significantly over the past five years.[802] The availability of solar power has grown even in Alaska. SEIA data shows that in Alaska, solar capacity has grown from essentially 0 MW in 2012 to 14.3 MW in 2021 and that it will grow another 30 MW over the next 5 years. It also shows that solar installations are increasingly commercial and estimates that the price for solar has dropped 11% over the past five years.[803]

Solar-powered systems can also be used at sites of various sizes. Although solar technology has been most commonly used at small and medium sites in the past, it is now available and cost-effective at larger sites due to the falling prices of photovoltaic (PV) panels and battery systems, improvements in PV output, and the ease of installing solar PV systems. Furthermore, operators have found that reliability has increased when using additional, vertically stacked solar panels[804] or an additional methanol fuel cell.[805]

***Without Grid Access – Other.***

- *On-site generator:* Although solar is cost-effective and viable in all regions, some sites without a grid connection may choose to use an on-site generator to power electronic controllers. This technology is readily available, and many sites already have power generation on-site for other purposes like lighting, automation, and control systems. The Joint Commenters are confident that despite secondary impacts, this option is also environmentally beneficial. Generator-run instrument air can produce NOx emissions, but the pollution benefits of using this technology

[798] Attachments O and P, PC Cost Memo and PC Cost Spreadsheet.
[799] Colorado Air Pollution Control Division, Pneumatic Controller Task Force Report 37 (June 2020).
[800] *See* Calscan Solutions, Zero GHG Venting Controls for Separators, http://www.calscan.net/solutions_ZeroGHGVenting.html (last visited Jan. 27, 2022).
[801] David McCabe Conversation with Henri Tessier, Calscan (Oct. 30, 2020).
[802] Attachment S, EIA Solar Capacity and Generation by Region and Year
[803] Attachment T, SEIA Alaska Solar
[804] Carbon Limits 2021 at 5-6.
[805] Carbon Limits 2021 at 6.

far outweigh the harm from those emissions. One analysis obtained emissions data from two vendors that supply engine/air compressor packages and found that these types of compressed air packages will prevent at least ninety times more VOC emissions (by weight) than the NOx emissions they produce.[806] Beyond natural gas generators, there are also thermoelectric generators that can convert waste heat in compressor exhaust to electricity.[807]

- *Solar with Genset Backup:* Electronic controllers can also be powered by a hybrid system of solar and gas-fired generation. Prefabricated units are available, and operators can choose between backup power systems using a genset or battery storage depending on cost, available space, and other factors.[808]

***A Note on Emergency Shutdown Systems***. Emergency shutdown ("ESD") systems are reliable control systems designed to protect personnel and the facilities in case of an unexpected event such as over pressurization. ESD valves are typically controlled by gas-driven devices. In 2016, when EPA issued OOOOa, electric valve systems were generally not considered to be reliable enough for ESD systems, so it was assumed that gas driven-controllers would still be used for ESD systems, even when the rest of the facility was converted to electronic controllers. Today, however, there are reliable zero-emission ESD systems on the market, including systems utilizing uninterruptible power supply device and systems utilizing a failsafe controller in an emergency shutdown valve electric actuators system.[809]

b. Instrument Air Controllers

Additionally, operators can install systems that use compressed instrument air rather than natural gas to drive controllers, eliminating methane emissions to the atmosphere. Generally, instrument air systems are a cost-effective option for operators because they require lower maintenance costs than natural gas-driven controllers, produce revenue by retaining the volume of gas available for sale, and can often use existing piping to move the compressed air.[810] They do, however, require access to electrical power to operate air compressors.

In some countries (e.g., Norway, Iran, Kazakhstan), a majority of pneumatic control systems run on instrument air.[811] One study that looked at over 260 production sites (wellpads and tank batteries) in British Columbia counted 2,120 controllers and found more air-driven controllers and pumps (891 units, 42%) than natural gas-driven devices (725 units, 34%).[812]

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[806] CATF, Comparison of NOx emissions to avoided VOC emissions for Colorado usage of commercially available compressed air packages (Jan. 2021).
[807] GTI, Developing an Integrated Thermoelectric System to Mitigate Methane Emissions Effectively, https://www.gti.energy/developing-an-integrated-thermoelectric-system-to-mitigate-methane-emissions-effectively/ (last retrieved Jan. 27 2022).
[808] WZI at 6.
[809] Carbon Limits 2021 at 7.
[810] WZI at 3.
[811] Carbon Limits 2016 at 17.
[812] British Columbia Oil and Gas Methane Emissions Field Study, Cap-Op Energy (2019).

***With Grid Access.*** Air-driven controllers are a highly reliable option for sites with connection to the electric grid, or with power nearby,[813] especially in light of the increased availability of power discussed previously.

Based on CATF analysis and using a multi-pollutant approach, for EPA's large model production site, abatement costs at existing sites accounting for the value of saved gas is $184/ton of methane for a site with wet gas and $232/ton of methane for a site with dry gas. At new, large production sites, costs are $107/ton methane for wet gas and $160/ton methane for dry gas.

Using a single-pollutant approach, for EPA's large model transmission and storage site, abatement costs at existing sites *without* accounting for the value of saved gas is $1,494/ton of methane. At new, large transmission and storage sites, costs are $1,443/ton of methane. For a transmission site the size of the U.S. average based on the GHG Inventory, the cost for existing sites drops to $1,028/ton of methane and the cost for new sites drops to $960/ton of methane. For a storage site the size of the U.S. average, again based on the GHG Inventory, the cost for existing sites drops to $397/ton of methane and the cost for new sites drops to $635/ton of methane.[814] These figures for transmission and storage sites do not include the value of saved gas, since companies often do not own the gas that they are transporting. In addition, we use the single-pollutant approach for costs in the transmission and storage segments, because low VOC levels in gas in these segments make VOC abatement costs high.

***Without Grid Access.***

- *Solar Instrument Air*: Instrument air devices can also be powered by solar generators. There are several manufacturers advancing this technology.[815]

- *On-site generator*: Like electric controllers, instrument air controllers can be powered by an on-site generator if grid access is unavailable.[816] And as with electronic controllers, the emission reduction benefits that operators can achieve by using instrument air devices instead of gas-powered controllers greatly outweigh the additional NOx emissions that would result from using an electric generator.

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[813] Carbon Limits 2016 at 18.
[814] Attachments O and P, PC Cost Memo and PC Cost Spreadsheet.
[815] Carbon Limits 2021 at 7-8. A new technology package called the Aurora Eco-System, offered by Air Works Compressors, provides an instrument air system powered by solar PV or wind power installed at the well-sites. As of mid-2021, the solar-powered Aurora Eco-System package has been installed in 22 sites in Alberta, Wyoming, Utah, and Peru. 2021. Carbon Limits 2021 at 7. Additionally, LCO technology markets the Crossfire Instrument Air Compressor (see https://lcotechnologies.com/crossfire-compressor.html ) and WestGen Technology markets the Engineered Power on Demand (EPOD) unit to provide sites with both compressed air and electricity. The unit derives most of its power from solar panels but supplements the solar with a small gas-driven engine (needed particularly in Canadian winters) (see https://westgentech.com/epod-ap-series/ ). Other examples include Alert Control Technologies, https://alertcontrol.com/air-compressors/ (last visited Jan. 27 2022); and Axiom Technologies LLC, https://axiomsafety.com/solar-powered-air-compressors/ (last visited Jan. 27 2022).
[816] Carbon Limits 2016 at 18.

- *Solar with Genset Backup*: Like electronic controllers, instrument air can be powered by a hybrid system of solar and generation. This option is discussed above in the electronic controllers section.

c. Nitrogen

When electricity is not available to power electronic or instrument air controllers, nitrogen provides a feasible zero-emission alternative to operating pneumatic devices. Unlike instrument air systems that require electric power, these systems only require the installation of a cryogenic liquid nitrogen cylinder, which is replaced or refilled periodically, and a liquid nitrogen vaporizer.[817] One company in British Columbia, Kathairos, provides a service that allows operators to store a quantity of liquid nitrogen at a site, which (after on-site gasification) provides a source of dry nitrogen gas to drive pneumatics instead of using natural gas.[818] The system requires no electricity or on-site power generation.[819]

d. Routing to a Process or Control Device

Emissions from pneumatic controllers can, alternatively, be controlled by routing the emissions to a process, such as an on-site VRU or fuel line to an on-site engine, boiler, or heater. A second option, inferior to routing to a process but certainly preferable to uncontrolled venting, is routing the emissions to a control device. While capturing gas that would otherwise be vented and routing it to a process is always preferable to flaring and must be prioritized under any proposed standard, routing to a completion combustion device should be permitted where venting would be an operator's only other option. While these options will not necessarily reduce emissions by 100%,[820] as discussed in subsections B and F, if EPA adopts a functional need exemption at processing plants and an operator demonstrates the applicable factors, EPA must require that operator to reduce emissions by 95%, with a preference for routing to a VRU rather than to a combustion device. The general approach of routing emissions to achieve 95% reductions as a next-best alternative is similar to the one EPA has taken in its proposed standards for pneumatic pumps at sites aside from gas processing plants (although, as we discuss below, we urge EPA to strengthen those requirements as well).

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[817] EPA, Lessons Learned: Natural Gas STAR Partners, *Options For Reducing Methane Emissions From Pneumatic Devices In The Natural Gas Industry*, (Oct. 2006), available at https://www.epa.gov/sites/default/files/2016-06/documents/ll_pneumatics.pdf

[818] Petroleum Alliance Technology Canada, PTAC TIS: Kathairos Introduces Novel Solution Using Liquid Nitrogen to Produce Zero Methane Emission Result https://www.ptac.org/events/ptac-tis-kathairos-introduces-novel-solution-using-liquid-nitrogen-to-produce-zero-methane-emission-result/ (last visited Jan. 27, 2022); *See also* Petroleum Alliance Technology Canada, Kathairos Introduces Novel Solution Using Liquid Nitrogen to Produce Zero Methane Emission Result (Dec. 2020), https://www.ptac.org/wp-content/uploads/2020/12/PTAC-TIS_-Kathairos-Introduces-Novel-Solution-Using-Liquid-Nitrogen-to-Produce-Zero-Methane-Emission-Result-1.pdf

[819] Comment submitted by Kathairos Solutions Inc. Posted Dec 16, 2021. https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-0384.

[820] "Thermal combustion devices (including flares) or vapor recovery systems are expected to achieve a 95 to 98 percent control efficiencies." TSD 6-16. EPA also assumes VRUs will capture 95% of emissions from pumps. TSD 9-9.

Wyoming's regulations require operators of controllers in the Upper Green River Basin to either install low- or zero-bleed controllers, or alternatively, route emissions "into a sales line, collection line, fuel supply line, or other closed loop system."[821] Some operators in Wyoming have chosen to take advantage of that alternative and have routed emissions from pneumatic controllers to fuel lines.[822] Similarly, Colorado's rules require that well production facilities and natural gas compressor stations use only "non-emitting controllers,"[823] which include electronic controllers and "routed pneumatic controllers."[824] Additionally, the California Air Resources Board (CARB) issued a rule which prohibits venting from any continuous-bleed pneumatic controller for both new and existing sources. To control emissions from these devices, CARB requires that operators either "[u]se compressed air or electricity to operate" or "collect all vented natural gas with the use of a vapor collection system" [825] that directs the collected vapors to either a sales gas system, fuel gas system, or gas disposal well.[826] If none of those are available, the operator *must* route to a control device, even if that means having to install one.[827] Furthermore, control devices in areas in attainment with all state and federal ambient air quality standards must achieve 95% vapor collection efficiency, and those in non-attainment areas must achieve at least 95% efficiency and not result in NOx emissions.[828] The rule permits vapor collection systems and control devices to be taken out of service for up to 30 calendar days per year for performing maintenance.[829] This approach would work for all types of pneumatic controllers.

The EPA didn't calculate cost-effectiveness for routing to a VRU from pneumatic controllers in its proposed rule, but, as discussed in section G.3.b, for its final rule we urge the agency to consider the faulty premises from which its 2016 and 2021 calculations for VRU cost-effectiveness were based, and to conduct a cost analysis for routing controllers to a VRU that is based on more reliable factors.

As discussed in that section, EPA's current cost analysis relies on three outdated VRU capital cost estimates, two of which are from the oil and gas industry. EPA should update its analysis to include a more representative sample, which we believe could result in greater cost-effectiveness for this approach. Indeed, should EPA omit the particularly high estimates provided by the Gas Processor

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[821] Wyoming Administrative Rules, Dep't of Environmental Quality, Air Quality, Chapter 8, Section 6(f).

[822] Department of Environmental Quality, Division of Air Quality, Permit Application Analysis (Nov. 10, 2011). This analysis covered QEP Energy Company's Mesa 3- 22 PAD (AP-12533) and Mesa 7-8 PAD (AP-15216). These examples were found in a review of a small number (23) of Wyoming oil and gas production facility air permits. Because of the small number of permits that were reviewed, we are unable to estimate how widespread this approach is in Wyoming.

[823] CO Regulation Number 7, Section D.III.C.4.a.

[824] CO Regulation Number 7, Section D.III.B.10.

[825] Cal. Code Regs. tit. § 95668(e)(5), available at https://casetext.com/regulation/california-code-of-regulations/title-17-public-health/division-3-air-resources/chapter-1-air-resources-board/subchapter-10-climate-change/article-4-regulations-to-achieve-greenhouse-gas-emission-reductions/subarticle-13-greenhouse-gas-emission-standards-for-crude-oil-and-natural-gas-facilities/section-95668-standards

[826] See Cal. Code Regs. tit. § 95668(e)(5)(a) referring to Cal. Code Regs. tit. § 95671(b), available at https://casetext.com/regulation/california-code-of-regulations/title-17-public-health/division-3-air-resources/chapter-1-air-resources-board/subchapter-10-climate-change/article-4-regulations-to-achieve-greenhouse-gas-emission-reductions/subarticle-13-greenhouse-gas-emission-standards-for-crude-oil-and-natural-gas-facilities/section-95671-vapor-collection-systems-and-vapor-control-devices

[827] Cal. Code Regs. tit. § 95671(c).

[828] Cal. Code Regs. tit. § 95671(d).

[829] Cal. Code Regs. tit. § 95671(f).

Association, the annualized costs for routing controllers to a VRU drops from $869 to $624 (2019 USD). Assuming EPA's reported emissions rate of 9.2 scf/hr for intermittent vent controllers, sites with at least 2 controllers will spend about $200 per ton of methane avoided without savings and will incur modest net savings at a gas price of $4 per Mcf (about $6 benefit per ton of methane avoided).[830]

5. *EPA Should Finalize A Zero-Emitting Standard for Intermittent Controllers.*

Joint Commenters strongly urge EPA to include in its final rule a requirement that operators use zero-bleed technology for intermittent controllers. According to EPA's own estimates, intermittent controllers account for over 85% of methane emissions from controllers in the oil and gas production segments.[831] We agree that this percentage and EPA's emissions factor for intermittent controllers (9.2 scfh), reflect reasonable estimates and therefore fully justify EPA's extension of zero-bleed standards to intermittent controllers.

First, even when operating properly, intermittent controllers emit a significant amount of methane. A study by Allen *et al.* (2015) showed that five of the 40 highest-emitting devices studied were intermittent controllers, with rates of up to 40 scfh.[832] Second, as demonstrated by several studies, intermittent controllers often improperly function by emitting continuously rather than only when actuating, which results in emissions that exceed these devices' design values:

- One study examining 70 pneumatic devices between June 2017 and May 2018 showed abnormal emissions behavior from over 60% of the 40 intermittent devices that were studied as well as from over 20% of the 24 low-bleed devices in the sample. These emissions were substantially higher than the standard emissions value stated by the device manufacturers. For intermittent controllers, an average of 16.1 scfh was emitted, substantially exceeding EPA's 13.5 scfh emissions factor, the API emission factor used by EPA in its 2021 TSD (9.2 scfh), and the controllers' advertised design value of only 2.8 scfh.[833]

- As described in a 2020 Pneumatic Controller Task Force (PCTF) Report, a field study was carried out in 2018 to study the operation of these devices in Colorado's ozone nonattainment area. One of the goals of this study was to document malfunction rates and causes for controllers. The study found that 5.6% of the inspected intermittent controllers were operating improperly.[834]

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[830] The revised capital cost estimate relies on the average of a $2,000 (EPA's 2016 estimate) and $5,800 (API's 2016 estimate) expenditure—both of which are included in EPA's 2016 calculations—and is adjusted from 2012 to annualized 2019 dollars using the same price deflator (12.3%) and capital recovery factor (.1424) that EPA used in its 2021 TSD. This cost is compared to avoided emissions of 9.2 scf/hr for two intermittent vent controllers at a site (see TSD Table 8-3).
[831] *See supra* footnote 754.
[832] David T. Allen et al., *Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers*, 49 Env't Sci. Tech. 633 (2015), http://pubs.acs.org/doi/abs/10.1021/es5040156
[833] Carbon Limits 2021 at 4.
[834] Colo. Air Pollution Control Div., *Pneumatic Controller Task Force Report to the Air Quality Control Commission*, 12 (June 1, 2020).

- A City of Fort Worth study that examined emissions from 489 intermittent-bleed devices using infrared cameras and other methods found that many controllers were emitting constantly and at very high rates, even though they were being used to operate separator dump valves and were not designed to emit between actuations.[835]

- Stovern *et al.* also studied pneumatic controllers in the Denver-Julesberg basin in 2018. This study directly observed that 11.3% of the intermittent controllers were emitting continuously due to a maintenance problem. However, the study notes that due to methodological issues, this 11.3% figure is probably an underestimate of the actual rate of malfunction among the intermittent controllers they inspected, which they estimate to be in the range of 11.6 – 13.6%.[836]

Additionally, measurements for intermittent controllers that capture the full impact of emissions from these sources are difficult to obtain, suggesting that their true quantity of emissions may exceed the data reported thus far. For example, in order to get measurements reflecting the full scope of emissions from intermittent controllers, Luck *et al.* (2019) found it necessary to install a flow meter on the line supplying gas to the pneumatic controller and measure the amount of gas flowing to the controller over a period of more than 24 hours. Measurements conducted for a shorter time would lead to an underestimate of controller emissions.[837] Additionally, Stovern *et al.* notes that there are significant limitations in the use of OGI for inspection of pneumatic controllers.[838] For these reasons, EPA's 9.2 schf emissions factor is a reasonable estimate.

Although the specific percentage of malfunctioning devices varies considerably across the studies cited above, they all confirm that intermittent controllers can and often do emit far more than their advertised design values indicate. These excess emissions can be easily and cost-effectively avoided by requiring operators to use the zero-emitting options discussed above for intermittent controllers. Thus, for EPA's zero-emission standard to constitute the "best" system of emission reduction, EPA must apply the standard to intermittent controllers.

#### 6. *EPA Should Not Include a Feasibility or Functional Need Exemption From Zero-emitting Technologies.*

EPA has solicited comment on whether it is technically feasible to require operators to install zero-emitting technologies and "the possibility of situations where functional requirements/needs dictate that a natural gas-driven controller that emits any amount of VOC and/or methane be used."[839] In its proposed rule, EPA has not included a feasibility exemption for the production and

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[835] Eastern Research Group, Inc. & Sage Env't Consulting, LP, *City of Fort Worth Natural Gas Air Quality Study*, 3–100 (July 13, 2011), http://fortworthtexas.gov/uploadedFiles/Gas_Wells/AirQualityStudy_final.pdf ("Under normal operation a pneumatic valve controller is designed to release a small amount of natural gas to the atmosphere during each unloading event. Due to contaminants in the natural gas stream, however, these controllers eventually fail (often within six months of installation) and begin leaking natural gas continually.").
[836] Stovern et al., *Understanding oil and gas pneumatic controllers in Denver-Julesburg basin using optical gas imaging*, 70 J. of the Air & Waste Management Assoc., 9 (2020), https://doi.org/10.1080/10962247.2020.1735576
[837] Luck et al. (2019).
[838] Stovern et al. at 4-5.
[839] 86 Fed. Reg. 63110, 63207 (Nov. 15, 2021).

transmission and storage segments,[840] but has included an "allowance for the use of natural gas-driven controllers with an emission rate…greater than zero where needed due to functional requirements" for natural gas processing plants.[841] For at least two reasons, EPA should not include a feasibility or functional need exemption from zero-emitting technologies. If it nevertheless includes such an exemption in the final rule, it must narrowly tailor it.

First, given the wide range of cost-effective technologies that are available to operators today, there is no need for a feasibility or functional need exemption in any segment. In the RIA, EPA states that it "assumes that all [processing] plants have access to reliable electricity"[842] that 40 percent of well sites have access to reliable electricity," and that the remaining 60 percent of well sites can install solar photovoltaic (PV) and battery systems.[843] It also assumes that "half of plants have or will, regardless of OOOOb requirements, install compressed air systems in the baseline."[844] These assumptions, which reflect analyses presented to state regulators, are justified given that operators self-reported having reliable electricity at 37% of their sites in 2015 and that solar is technically feasible in most regions, including Canada. It is clear, then, that installing electronic or instrument-air controllers is broadly feasible. There is especially little need for a feasibility exemption at processing plants which, according to EPA, are generally assumed to have electricity and have been required to install zero-emitting devices for new sources since EPA's 2012 OOOO rule.[845] And, as operators have demonstrated, *see supra* Part II.C.3, sites are already being retrofitted without feasibility exemptions. In California, which has a zero-emission standard for continuous controllers, there is no feasibility exemption at all, and those standards have been successfully implemented by the state.

Second, including a broad feasibility or functional need exemption could have significant consequences. If, for example, EPA exempted sites that claim to lack immediate access to "reliable electricity," that would encompass 60% of well sites,[846] resulting in hundreds of thousands or even over a million metric tons of methane in a year.[847] These potential consequences are unnecessary. As discussed above, operators that currently lack access to grid electricity can either gain access to it or install zero-emitting devices that do not require grid power, of which there are multiple options that are cost-effective and commercially available.

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[840] *Id.*
[841] 86 Fed. Reg. 63110, 63208 (Nov. 15, 2021).
[842] RIA at 2-21-2-22.
[843] RIA at 2-17.
[844] RIA at 2-22.
[845] In its TSD, EPA states that in the years 2011-2012 and 2015-2016, "the EPA assumed that electric power would be available at new gas processing plants, but because electric power would not necessarily be available at other oil and gas production locations, the EPA determined that the use of instrument air systems and electrically powered mechanical controllers would not be practically feasible outside of gas processing plants." TSD 8-5. Further, in its proposal, EPA states "The 2012 NSPS OOOO and 2016 NSPS OOOOa require a zero-bleed emission rate for pneumatic controllers at natural gas processing plants. *Natural gas processing plants have successfully met this standard for many years now*. Further, several State agencies have rules that include this zero-bleed requirement for controllers at natural gas processing plant." 86 Fed. Reg. 63110, 63208 (Nov. 15, 2021) (emphasis added).
[846] EPA assumes that 40% of well sites have access to "reliable electricity" and that the remaining 60 percent of well sites can install solar photovoltaic (PV) and battery systems to power zero-emitting controllers. See RIA at 2-17.
[847] Metric tons calculated by taking 60% of EPA's production segment emissions estimates.

If EPA does include a functional need exemption for processing plants (or in any segment), it must require that qualifying operators still reduce emissions, even if they do not install zero-bleed technology, and that they provide a functional need justification in their annual reports. In Colorado, operators that seek to rely on the safety exemption for both new and existing sources must submit a justification for safety or process purposes forty-five days prior to installing an emitting device or retrofitting the facility.[848] In New Mexico, regulators are proposing a zero-emitting pneumatics rule that has a safety exemption for new and existing sources, which applies only where operators demonstrate necessity based on functional needs (including response time, safety, and positive actuation).[849]

Any feasibility exemption in the final rule must be well-designed like these states' programs to ensure that operators install zero-bleed technology except where an exemption is truly necessary. Operators should be required to first attempt to reduce emissions by at least 95%, with a preference for routing to a process rather than a control device. If neither of these options is feasible, the operator must be required to reduce emissions to the greatest extent possible. In these instances, operators must provide a functional need justification in their annual report. Any justification should, at minimum, include documentation as to (1) why power (either grid-based or solar) is unavailable; (2) if applicable, and if the operator isn't routing to a process or control device or achieving 95% reductions, why meeting those standards is infeasible; and (3) how the operator plans to minimize emissions to the maximum extent possible. In any instances where operators utilize continuous-bleed or intermittent-bleed controllers, they should be required to comply with the finalized recordkeeping and LDAR standards. Even more, given persistent malfunctions from pneumatic controllers, EPA should consider enhancing LDAR standards for sites that are not capable of installing zero-bleed controllers.

### 7. *EPA Should Not Extend the Categorical Exemption Beyond Alaska.*

EPA's proposal currently includes a categorical exemption for sites in Alaska where power is not available. At these locations, operators can either use intermittent-bleed controllers or continuous low-bleed controllers (unless a high-bleed controller is needed for functional reasons).[850] Furthermore, in these instances, EPA proposes to require operators to inspect intermittent controllers as part of their LDAR requirements to ensure they are not venting when idle.[851]

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[848] CO Regulation Number 7, Section D.III.C.4.e.(i)(A)(1)-(2); D.III.C.4.e.(i)(D)(1). Colorado also has an exemption for pneumatic controllers that emit natural gas located on temporary or portable equipment, but to receive the benefit of that exemption the operator must submit a plan for approval that justifies the need. Colorado Regulation Number 7, Section D.III.C.4.e.(i)(C)(3). Further, Colorado also has an exemption for pneumatic controllers that emit natural gas to the atmosphere that are used as emergency shutdown devices and for artificial lift control located on a wellhead: (1) greater than one quarter mile from the associated production facilities for well production facilities that commenced operation on or after May 1, 2021; or (2) not located on the same surface disturbance as the associated production facilities for well production facilities that commenced operation before May 1, 2021. In that case, the operator must inspect the controllers using an approved monitoring method, and comply with the repair, recordkeeping, and reporting provisions of the rule. Colorado Regulation Number 7, Section D.III.C.4.e.(i)(D)(3)

[849] See proposed NM Rule, 20.2.50.122 (B)4(c)(vi): "if after January 1, 2027, an owner or operator's remaining pneumatic 7 controllers are not cost-effective to retrofit, the owner or operator shall submit a cost analysis of retrofitting those 8 remaining units to the department. The department shall review the cost analysis and determine whether those units qualify for a waiver from meeting additional retrofit requirements."

[850] Fed Reg 63110, 63179

[851] Fed Reg 63110, 63179.

EPA should limit this blanket exemption only to Alaska in the finalized rule. Even operators in Alberta are required to install zero-emitting pneumatic devices. And in Alaska, where the reason for an exception is more compelling than in other U.S. regions because the applicability of solar is somewhat uncertain, operators largely use instrument air and, as discussed, the availability of solar is increasing significantly.[852] If the feasibility of zero-emitting technology is growing in Alberta, Alaska and other northern regions, then there is certainly no reason to extend the proposed blanket exemption to geographies beyond Alaska.[853]

8. *EPA Should Require That Operators Retrofit Existing Facilities Within Two Years of the Deadline for State Plans.*

EPA has proposed a requirement that operators retrofit their existing pneumatic controllers to zero-emitting devices within two years of the deadline for state plan submission. A two-year timeframe appropriately reflects the BSER because it addresses the urgent need to replace old, polluting controllers while providing operators several years from the time of the finalized rule[854] to acquire and install zero-emitting controllers. Natural gas producer EQT will complete a full retrofit within two years, and Diamondback anticipates it will have replaced "nearly all" of its controllers with zero-emitting devices within four years. Further, the finalized rule will signal to suppliers the need to ramp up production well in advance of the retrofit deadline, increasing the likelihood of sufficient market availability for suppliers by that time. Once EPA finalizes its standards, the demand from operators seeking pneumatic controllers will prompt manufacturers of pneumatic devices to scale production quickly. One supplier that EDF spoke with specifically noted that based on prior experience it anticipates that it will scale production to fill a market gap as supply demand increases in response to the rule.

Moreover, retrofitting large sites that have higher numbers of pneumatic controllers will be easily achievable and cost-effective. The non-emitting equipment will eliminate a large amount of emissions, generating revenue in many cases, while compliance costs of the equipment are somewhat limited because common equipment for non-emitting control systems, such as solar panels and batteries, can be shared for a larger group of controllers. As the retrofit requirements increase, operators will need to address smaller sites, but technology improvements and economies of scale in the intervening years will likely mitigate costs at those sites.

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[852] Attachment T, SEIA Alaska Solar

[853] Feasibility in Alaska is also reason to consider not including a blanket exemption for the state, though we don't go into detail on that issue in this comment. At the very least, EPA should address the environmental justice concerns that arise because of the exemption. As the National Tribal Air Association has remarked, the proposal as it stands doesn't adequately protect Alaska Native Villagers and Alaskan Tribes and ensure sufficient consultation and coordination with Tribes. To address that, EPA should develop Tribal Plans, and create systems for tribal governments to participate in monitoring and state plan development. *See* National Tribal Air Association, NTAA's Informational Webinar on EPA's Oil & Natural Gas Rule (Jan. 19, 2022), https://secureservercdn.net/198.71.233.206/7vv.611.myftpupload.com/wp-content/uploads/2022/01/NTAA-Presentatoin-for-Methane-Informational-Webinar-1.19.22.pdf
We urge EPA to consider these concerns when finalizing its rule.

[854] EPA projects it will finalize its rule in Spring 2022 and that impacts for existing controllers will begin in 2026.

For these reasons, EPA has selected a proper timeframe for retrofitting existing sites with zero-bleed controllers, and should retain this schedule in the final rule.

### D. Liquids Unloading

Joint Environmental Commenters strongly support EPA's proposal to regulate liquids unloading, and specifically to require that liquids unloading be performed with zero methane or VOC emissions. It is entirely feasible for these events to be conducted using techniques or technologies that eliminate or minimize venting to the maximum extent feasible. We support Option 1 of EPA's proposal because it is essential that records be kept of liquids unloading events in order for the agency, the public, and operators to understand when and why liquids unloading could not be conducted with zero emissions.

Under Option 1, EPA proposes to define the affected facility as every well that undergoes liquids unloading, meaning that wells utilizing a non-emitting method for liquids unloading would be affected facilities and subject to certain reporting and recordkeeping requirements. This is a critical requirement to ensure that operators do not simply claim to conduct liquids unloading events with zero emission techniques, when in reality venting is occurring anyway. As EPA has recognized, "under some circumstances venting could occur when a selected liquids unloading method that is designed to not vent to the atmosphere is not properly applied (*e.g.*, a technology malfunction or operator error)."[855] In some cases, the malfunction or error could be so great that it results in venting 100% of the gas intended to be captured. Because of this, EPA must require recordkeeping so it is aware of these events and overall emissions, and to build an understanding of what causes these errors and how they can be prevented. EPA should therefore finalize Option 1 and require operators to maintain records of the number of unloading events that occur, the method used, and any venting that occurred.

EPA should likewise limit permissible circumstances when liquids unloading can be conducted without zero emissions and require rigorous documentation of why venting had to occur. EPA has proposed to allow venting if "it is technically infeasible or not safe to perform liquids unloading with zero emissions," in which case EPA proposes "to require that an owner or operator establish and follow [best management practices] to minimize methane and VOC emissions during liquids unloading events to the extent possible."[856] EPA does not intend to "dictate all of the specific practices that must be included," but rather "would specify minimum acceptance criteria required for the types and nature of the practices."[857] This is too nebulous and is likely to result in regular venting, followed by operators checking off a handful of best practices. EPA should instead clearly define best practices, list them in hierarchical order, and require operators to follow the practices or otherwise provide rigorous documentation as to why they could not do so.

[855] 86 Fed. Reg. 63,179.
[856] 86 Fed. Reg. 63,179
[857] *Id.*

### E. Reciprocating Compressors

Joint Commenters support key aspects of EPA's proposed standards for reciprocating compressors, including extending requirements to existing sources and to centralized production facilities in the production segment. We urge EPA to further strengthen the standards in key respects—particularly by lowering the emissions threshold for rod packing replacement based on annual monitoring. We also encourage EPA to consider measures to reduce the significant emissions from compressor exhaust.

Joint Commenters strongly support extending reciprocating compressor standards to existing sources. As EPA explains, there is no reason to believe baseline emissions or mitigation costs would differ between new and existing reciprocating compressors.[858] Reciprocating compressors are a major source of methane emissions—responsible for 865,900 tons of methane in 2019, according to EPA's Greenhouse Gas Inventory—and must be controlled to the greatest extent possible. This requires standards for both new and existing sources.

Joint Commenters also support EPA's proposed definition of a centralized production facility, and support the extension of compressor standards to these sites. While the Greenhouse Gas Inventory does not contain data on the number of compressors in the production segment, EDF analyzed data submitted in response to EPA's 2016 Information Collection Request to assess the number of compressors across different facility types in the production segment. While the ICR data is not a full inventory, it illustrates that there are a significant number of compressors utilized in the production segment, with the substantial majority of reciprocating compressors located at centralized production facilities.

[858] 86 Fed. Reg. at 63,219.

**Figure 25: ICR Compressor Counts at Wellsites and Centralized Production Facilities**

| Equipment Type | Wellsite Equipment Count | CPF Equipment Count | Total Equipment Count |
|---|---|---|---|
| Reciprocating compressors | 7,508 (27%) | 21,204 (73%) | 28,712 |
| Dry seal compressors | 377 (35%) | 707 (65%) | 1,084 |
| Wet seal compressors | 257 (1%) | 22,935 (99%) | 23,192 |
| Total | 8,142 (15%) | 44,896 (85%) | 52,988 |

With EPA's proposal to link rod packing replacement requirements to annual monitoring, rather than to a three-year fixed replacement schedule, it is critically important that EPA lower the emissions threshold for replacing rod packing. EPA has proposed requiring replacement when emissions exceed 2 scfm, which the agency estimates will achieve a 92% reduction in emissions for reciprocating compressors in all segments.[859] However, as explained in CATF's Reciprocating Compressor Cost Memo and Spreadsheet (Attachments U and V), EPA likely overestimates the emissions reductions associated with replacement at the 2 scfm threshold, because only compressors with emissions that exceed that threshold will replace rod packing and thus reduce emissions. For compressors with emissions below that threshold, there will be no reduction in emissions.

To ensure emissions are meaningfully reduced based on an annual monitoring program, EPA should lower the threshold for replacement to 0.5 scfm, which we estimate will reduce approximately 80% of compressor station emissions while remaining highly cost-effective. While EPA did not estimate the cost-effectiveness of replacement at lower thresholds, CATF estimates that imposing a 0.5 scfm threshold for rod packing replacement would entail a cost of $270/ton of methane, not accounting for gas savings, and $89/ton of methane after accounting for gas savings at gathering and boosting compressors, which is the highest cost segment. Figure 26 shows the

[859] EPA TSD, Spreadsheet, Chapter 7 - 2021 Compressors Costs and Emissions.

cost summary for all segments; these abatement costs are very similar to costs for the current OOOOa requirement for new sources as shown in EPA TSD Tables 7-9 and 7-10. A detailed description of cost calculation methodology is in the attached Reciprocating Compressor Cost Memo and Spreadsheet. A lower threshold is also in line with standards adopted in Canadian jurisdictions, which, as EPA notes, require rod packing replacement at vent volume thresholds ranging from 0.49 to 0.81 scfm/cylinder.[860]

**Figure 26: Costs of rod packing replacement with a 0.5 scfm threshold (single pollutant costs)**

| Segment | VOC Cost of Control w/o Savings ($/ton) | VOC Cost of Control with Savings ($/ton) | Methane Cost of Control w/o Savings ($/ton) | Methane Cost of Control with Savings ($/ton) |
|---|---|---|---|---|
| Gathering and Boosting | $972 | $319 | $270 | $89 |
| Processing | $417 | ($236) | $116 | ($66) |
| Transmission | $4,432 | | $123 | |
| Storage | $5,462 | | $151 | |

Finally, EPA should develop standards to reduce emissions from compressor exhaust. EDF estimates 393,355 tons of methane emissions resulting from gathering and boosting compressor exhaust in 2019. As Joint Commenters have recommended to EPA in the past, EPA should consider requiring that compressors be driven by turbines or electric motors, since according to emissions factors in the GHGI, turbines produce less methane per horsepower-hour than RICE engines by about a factor of 25.[861]

### F. Centrifugal Compressors

Joint Commenters strongly support extending centrifugal compressor standards to existing sources and to centrifugal compressors at centralized production facilities. There are significant emissions associated with centrifugal compressors—78,700 tons of methane from wet seal compressors and 88,000 tons of methane from dry seal compressors in 2019, according to the 2021 GHGI. EPA should further strengthen the wet seal compressor standards by prioritizing control methods that route captured gas to a process rather than a completion device and should set standards to reduce emissions from dry seal compressors.

For wet seal centrifugal compressors, EPA's proposed standards would require an emissions reduction of 95%, which operators could achieve by routing captured gas to either a process or control device. EPA should strengthen this standard by requiring that operators route all captured emissions to a process and only permit the use of a combustion device where an operator submits documentation showing it is technically infeasible to route to a process. EPA's analysis demonstrates that routing to a process is by far the more cost-effective option at $14-26 per ton of methane reduced without accounting for gas savings (and paying for itself in the production and

[860] 86 Fed. Reg. at 63,218 (citing Canadian Federal standards: http://gazette.gc.ca/rp-pr/p2/2018/2018-04-26-x1/pdf/g2-152x1.pdf).
[861] Sierra Club et al., Comments on New Source Performance Standards: Oil and Natural Gas Sector; Review and Proposed Rule for Subpart OOOO, 48 (Nov. 30, 2011).

processing segments when accounting for gas savings). In comparison, routing emissions to a new combustion device costs $640-1160 per ton of methane reduced.[862]

EPA acknowledges that routing captured gas to a combustion device emits harmful co-pollutants, including NOX, CO2, and CO emissions, but expresses doubt that "capturing leaking gas and routing to the process can be achieved in all circumstances."[863] In particular, EPA points to feedback received during development of the 2012 NSPS OOOO and 2016 NSPS OOOOa rulemakings claiming that routing to a process "may not be a viable option in situations where there may not be down-stream equipment capable of handling a low-pressure fuel source."[864] However, EPA can address these concerns by setting a default standard that requires routing captured gas to a process while permitting the use of a combustion device in limited cases where an operator demonstrates it is technically infeasible to route to a process. EPA can also consider the approach taken by California, which requires operators to route emissions from wet seal compressors to a vapor collection unit, with an alternative of repair when monitored flow rate exceeds 3 scfm.

Finally, given the significant aggregate emissions from dry seal compressors, EPA should consider issuing standards to reduce emissions from those sources. In particular, EPA should evaluate whether to require that dry seal compressors install tandem seals, which substantially improve emissions control. According to EPA, such seals are "very effective in reducing gas leakage," as "[t]his type of seal has less than one percent of the leakage of a wet seal system vented into the atmosphere and costs considerably less to operate."[865]

### G. Pneumatic Pumps

#### 1. *EPA's Proposal*

EPA's proposal includes standards for air pollution from new, modified and existing pneumatic diaphragm pumps and piston pumps. These devices use the energy of high-pressure natural gas to pump a liquid, typically venting low pressure natural gas to the atmosphere. Pneumatic pumps emit substantial amounts of pollution into the atmosphere–typically more per device than pneumatic controllers– and protective standards for these sources are therefore critical.[866] We generally support EPA's proposed measures for pneumatic pumps. For new sources, the proposal would require that diaphragm and piston pumps at processing plants emit zero natural gas. For new diaphragm and piston pumps in the production segment and new diaphragm pumps in the transmission and storage segments, the proposal would require operators to reduce emissions by

[862] 86 Fed. Reg. at 63,222-23; EPA 2021 TSD at 7-35.
[863] 86 Fed. Reg. at 63,223.
[864] *Id.*
[865] EPA Natural Gas STAR, *Lessons Learned: Replacing Wet Seals with Dry Seals in Centrifugal Compressors* (October 2006), https://www.epa.gov/sites/default/files/2016-06/documents/ll_wetseals.pdf.
[866] Carbon Limits, *Zero emission technologies for pneumatic controllers in the USA: Applicability and cost effectiveness*, (Aug. 2016) ("Carbon Limits 2016"), 13-27, available at https://www.carbonlimits.no/project/zero-emission-technologies-pneumatic-controllers-in-usa/

95% if a control device or process already exists onsite. The requirements for existing sources would mirror those for new sources but exclude piston pumps.

These requirements are cost-effective. In the production segment, EPA estimates that the annual cost of installing an electric pump is $445 for diaphragm pumps and $551 for piston pumps,[867] and that the annual cost of routing emissions from a pump to a VRU or control device for new and existing sources is $273 for diaphragm pumps and $803 for piston pumps.[868] Based on these costs, EPA estimates that electronic pumps will cost $129 per ton of methane and $462 per ton of VOC abated for diaphragm pumps and $1,450 per ton of methane abated for piston pumps.[869] Additionally, EPA estimates that routing to a VRU or control device will cost $83 per ton of methane and $298 per ton of VOC abated for diaphragm pumps and $2,225 per ton of methane abated for piston pumps.[870] These estimates are within the range historically considered to be cost-effective by EPA. The requirements are similarly cost-effective in other segments.

2. *Current Emissions*

As shown in Figure 27, compared to pneumatic controllers, pneumatic pumps emit a lower but still significant amount of emissions, mostly from the production segment.

**Figure 27**

| **Segment** | **Pump type** | | **Emissions (mt)** |
|---|---|---|---|
| Production (Petroleum) | Chemical Injection Pumps | mt Methane (%) | 75,200<br>(26.1%) |
| | | Number of Pumps | 49,614 |
| Production (Natural Gas) | Chemical Injection Pumps | mt Methane (%) | 112,800<br>(39.2%) |
| | | Number of Pumps | 74,182 |
| Production (Natural Gas) | Kimray Pumps | mt Methane (%) | 73,400<br>(25.5%) |
| | | Number of Pumps | **Not estimated** |
| Gathering and Boosting (Natural Gas) | Pneumatic Pumps | mt Methane (%) | 26,500<br>(9.2%) |
| | | Number of Pumps | 15,536 |
| Totals | All pneumatic pumps | mt Methane | 287,900 |
| | | Number of Pumps | 139,332 |

[867] TSD 9-18., Table 9-10.
[868] TSD 9-14, Table 9-6.
[869] TSD 9-18, Table 9-10.
[870] TSD 9-14, Table 9-6.

Source: 2021 GHGI

### 3. *EPA Must Strengthen its Rule for Pneumatic Pumps*

EPA's proposed pump rule takes steps in the right direction but must be strengthened in the ways we discuss below.

#### a. EPA Should Create a Zero-Emission Standard for Pneumatic Pumps in All Segments

First, EPA's proposal does not require non-emitting pumps at sites other than processing plants despite the fact that it would be technically feasible and cost-effective to do so. Electricity is often readily available at compressor stations, large production sites, and sites near urban areas. And as explained in Section C, the availability of electricity at sites other than processing plants has increased significantly since 2016. Furthermore, for operators that are unable to connect to the grid, solar pumps are available and have become widespread over the past five years, and for sites with high demand, thermal electric generators or methanol fuel cells have been used to increase power.[871] The application of a zero-emitting standard in other jurisdictions and the widespread use of non-emitting pumps by oil and gas operators is further evidence of the feasibility of a zero-emissions standard. Alberta and California currently require zero-emitting new and existing pumps, and New Mexico has proposed a rule requiring zero-emitting pumps at all processing plants and at wellhead sites, gathering and boosting sites, and transmission compressor stations with electricity.[872] Moreover, EOG Resources, which operates throughout the U.S., has started an initiative to "[c]onvert[] pneumatic pumps to electric or solar power."[873]

At the very least, EPA should require zero-emitting pumps at sites that are transitioning to zero-emitting pneumatic controllers (on their own or because of the new standards). Operators who install systems that can operate zero-emitting controllers should easily be able to scale those systems to operate zero-emitting pump equipment as well. For both electric and instrument air systems, converting pneumatic pumps to zero-bleed alongside pneumatic controllers adds to overall capital costs, but this is more than made up for by emission reductions which result in an overall decline in abatement costs. The Carbon Limits model supports requiring a zero-emission standard for pumps at sites installing zero-emitting controllers. It demonstrates that both new and existing sites[874] that convert controllers and also convert a pump to electric[875] have lower abatement costs than sites that only convert controllers.[876] The report notes the net benefit to operators arises because pumps typically emit more per device than controllers.

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[871] Carbon Limits 2016 at 13, 16.
[872] NM proposed rule, 20.2.50.122(B)(5).
[873] EOG Resources, 2019 Sustainability Report 6 (2019) https://eogresources-com.s3-us-west-2.amazonaws.com/EOG_2019_Sustainability_Report.pdf
[874] Carbon Limits 2016 at 25.
[875] Carbon Limits 2016 at 23.
[876] Carbon Limits 2016, 26-27.

Requiring zero-emitting pumps is cost-effective. Per EPA's own analysis, electric pumps generally cost $129 per ton of methane abated for diaphragm pumps and $1,450 per ton of methane abated for piston pumps,[877] both well within EPA's historical range of cost-effectiveness for methane controls. Solar pumps cost even less, at $78 and $756 per ton of methane abated for new diaphragm and piston pumps, respectively.[878] Though EPA's own analyses show zero-emitting pumps are cost-effective as is, we encourage EPA to consider the costs of controllers and pumps together, as that further improves cost-effectiveness. As the Carbon Limits model shows, sites with controllers that also have one pump that converts to electric power have a much lower abatement cost than sites without such a pump.[879]

b. If Zero-Emitting Technology Is Not Feasible for an Operator, EPA Should Require that the Operator Reduce Emissions by 95% and Submit Justification for an Exemption in its Annual Report.

While zero-emitting pumps are an available and cost-effective technology, EPA may nevertheless allow for certain exemptions in the final rule.[880] If EPA includes a feasibility exemption, it should require standards for pumps that closely resemble our suggested standards for pneumatic controllers. That is, EPA should require that operators first attempt to reduce emissions by at least 95%, with a preference for routing emissions to a VRU rather than to a combustion device. If that level of control is not feasible, operators must reduce emissions to the greatest extent possible. In these instances, operators should be required to provide a functional need justification in their annual report, including documentation as to (1) why power (either grid-based or solar) is unavailable; (2) if applicable and the operator isn't achieving 95% reductions, why reducing emissions by 95% is infeasible; and (3) how the operator plans to reduce emissions from their pneumatic pumps to the maximum extent possible.

There is evidence to suggest these alternative approaches are cost-effective. EPA estimates that in the production segment routing to an existing combustion device would be $264 per ton of methane avoided, well below the range historically considered cost-effective by EPA.[881] Routing to an existing VRU is equally cost-effective, at $264 and $83 per ton of methane avoided without and with cost savings, respectively.[882] Routing to an existing combustion device or VRU are thus cost-effective solutions for operators who cannot install zero-emitting pumps.

EPA's costs for routing to a new combustion device and VRU are higher. However, there is reason to believe EPA's VRU calculations overestimate costs. As a result, EPA should reconsider its VRU cost calculations for the final rule.

In the 2015 proposed OOOOa, EPA estimated the annualized cost for routing to a process to be $285. In the final rule, EPA altered that number to an annualized cost of $774. It based its decision

[877] TSD 9-18, Table 9-10.
[878] TSD 9-21, Table 9-12.
[879] Carbon Limits 2016 at 26.
[880] Carbon Limits 2016 at 12.
[881] TSD at 9-14.
[882] *Id.*

on two comments to the 2015 proposal. One commenter claimed that there were engineering costs in addition to the cost to pipe emissions in a closed vent system (CVS) to a control device, resulting in increased capital costs.[883] Another commenter -- Gas Processor Association (”GPA”) -- provided detailed cost with respect to installing a CVS that considers that there could be a significant distance between a pump location and the control device on a site.[884] In response to those comments, in the final rule the EPA calculated the average of the capital cost from the proposal and the two commenter estimates, which resulted in a revised annualized cost of $774.

EPA’s decision to base its cost analysis for VRUs in this proposal on those 2016 estimates is inherently flawed and arbitrary for several reasons. First, those values are outdated, and it’s unclear how representative they are. EPA did not explain how it vetted the commenter’s asserted capital cost increases before accepting them and including them in their final rule. And the result was not slight – annualized costs increased from $285 to $774 (2012 USD). Second, GPA’s cost estimate assumed a $7,000 (2012 USD) component to account for 200 feet of piping. This accounts for over 80 percent of the included cost estimate. This is problematic because few sites will need such a large length of piping. As a result, this heightened cost doesn’t apply to a significant number of sites governed by the proposed rule.

For these reasons, we urge the agency to re-consider its 2016 and 2021 calculations for VRU cost-effectiveness, especially for routing to a new VRU, and to conduct a cost analysis based on more reliable inputs.

### H. Equipment Leaks at Natural Gas Processing Plants

Joint Environmental Commenters strongly support EPA’s proposal to require bimonthly OGI monitoring in accordance with Appendix K for all pumps, valves, and connectors located within affected process units at onshore natural gas processing plants. This is an appropriate BSER for both new and existing processing plants that is cost-effective and can significantly reduce emissions.

The primary sources of equipment leaks at natural gas processing plants are pumps, valves, and connectors. The major cause of valve and connector leaks is a seal or gasket failure due to normal wear or improper maintenance. For pumps, emissions often result from a seal failure. The large number of valves, pumps, and connectors at processing plants means emissions from these components can be significant.

Common classifications of equipment at natural gas processing facilities include components in VOC service and in non-VOC service. “In VOC service” is defined as a component containing or in contact with a process fluid that is at least 10 percent VOC by weight or a component “in wet gas service,” which is a component containing or in contact with field gas before extraction. “In

[883] American Petroleum Institute comments submitted to the EPA Re: Environmental Protection Agency’s Oil and Natural Gas Sector: Emission Standards for New and Modified Sources at 80 FR 56593 (September 18, 2015). December 4, 2015. [EPA-HQ-OAR-2010-0505-6884-A1].
[884] Gas Processors Association comments submitted to the EPA Re: Environmental Protection Agency’s Oil and Natural Gas Sector: Emission Standards for New and Modified Sources at 80 FR 56593 (September 18, 2015). December 4, 2015. [EPA-HQ-OAR-2010-0505-6881.].

non-VOC service" is defined as a component in methane service (at least 10 percent methane) that is not also in VOC service.

The most common technique to reduce emissions from equipment leaks is to implement an LDAR program. Regular LDAR inspections can reduce product losses, increase safety for workers and operators, decrease exposure for the surrounding community, reduce emissions fees, and help facilities avoid enforcement actions. The effectiveness of an LDAR program is based on the frequency of monitoring, leak definition, frequency of leaks, percentage of leaks that are repaired, and the percentage of recurring leaks.

We support EPA's proposal to eliminate the "in VOC service" distinction for purposes of LDAR inspections and instead require bimonthly OGI at all pumps, valves, and connectors located within affected process units at processing plants. EPA is correct that "a VOC concentration threshold bears no relationship to the LDAR for methane and is therefore not an appropriate threshold for determining whether LDAR for methane applies."[885] EPA is also correct that "since there would be no threshold for requiring LDAR for methane, any equipment not in VOC service would still be required to conduct LDAR for methane even if not for VOC." Accordingly, it is appropriate to eliminate the VOC threshold for the purposes of this LDAR program.

EPA also should extend bimonthly OGI monitoring to any equipment or components designated as having no detectable emissions. As bimonthly monitoring will already be required, surveying additional components and equipment will add very little cost. This is an inexpensive solution for ensuring compliance that will also help operators detect any anomalous sources at the processing plant.

We also support the proposed repair timeframe that would require leaks detected by OGI to be repaired within 5 days of detection, and final repairs completed no later than 15 days of detection. When leaking valves need to be replaced, EPA should consider requiring Low-E valves and packing be installed. In a recent rulemaking, Colorado found these options to be similar in cost to non-Low-E valves and packing and directed operators to consider them.[886] Some manufacturers claim their Low-E packing can reduce emissions of harmful gases by up to 95% versus valves with traditional packing, with minimal cost impacts.[887]

### I. Oil Wells with Associated Gas (Venting & Flaring)

During the oil extraction process, a significant amount of natural gas is often produced as "associated gas" along with the oil.[888] This occurs with both conventional drilling and hydraulic fracturing, but associated gas is produced in particularly large quantities at hydraulically fractured

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[885] 86 Fed. Reg. 63,182.
[886] *See* Colorado Air Pollution Control Division, Rebuttal Prehearing Statement, Proposed Revisions to Regulation Numbers 7 and 22 (Dec. 14-17, 2021), https://drive.google.com/drive/folders/1mDU8Wc3iB_E4lj36R8AK_y8ptcU83Yao
[887] *Id.*
[888] *See, e.g.*, U.S. Energy Information Administration, Associated Gas Contributes to Growth in U.S. Natural Gas Production (Nov. 4, 2019), https://www.eia.gov/todayinenergy/detail.php?id=41873. *See also* Attachment W at 19, reporting nearly 40 billion cubic feet (bcf) per day of associated gas produced.

oil wells.[889] Most of the time, this gas is captured and sold for energy production along with the oil; but in some cases, operators fail to ensure there is appropriate infrastructure to capture the gas, and choose instead to dispose of it as a waste product by releasing it into the atmosphere. There are two methods for doing so: (1) venting, or simply opening a valve and releasing the gas in its natural state (which is mostly methane, but also includes heavier hydrocarbons and other compounds); and (2) flaring, which means that most of the gas is burned and transformed from methane into CO2 and other gasses before being released into the atmosphere, although a portion of the methane and other constituents of the gas, such as VOCs, is still released unburned.[890]

Venting and flaring are deeply wasteful and highly polluting practices. Venting is especially damaging due to methane's very high potency as a greenhouse gas.[891] Flaring, however, also produces a significant amount of greenhouse gas emissions,[892] both in the form of CO2 and because even in ideal flaring conditions, not all methane is combusted.[893] In practice, many flares malfunction, with significant methane slip rate, or are left unlit.[894] As a result, using flaring to dispose of associated gas produces massive methane and other greenhouse gas emissions across the United States every year. According to estimates by EDF and Rystad Energy, flaring releases approximately 200,000 tons of methane into the atmosphere every year in the Permian Basin alone,[895] of which 87% is due to flaring from associated gas production.[896] Moreover, due to a combination of high initial production of associated gas and delays in developing gathering line infrastructure or other gas capture methods, new wells tend to flare at particularly high volumes.[897] For example, wells drilled since 2018 accounted for 60% of all flaring in October 2021.[898] Colorado[899] and New Mexico[900] have already taken action to eliminate both venting and flaring in all non-emergency conditions, and we urge EPA to do the same.

EPA proposes to reduce emissions from venting and flaring of associated gas at oil wells. Specifically, EPA proposes to eliminate venting except in cases of emergency, although it retains

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[889] Clean Air Task Force, Regulating Flaring and Venting of Associated Gas Under CAA Section 111 at 11.
[890] U.S. DEPARTMENT OF ENERGY, Natural Gas Flaring and Venting: State and Federal Regulatory Overview, Trends, and Impacts (Jun. 2019), https://www.energy.gov/sites/prod/files/2019/08/f65/Natural%20Gas%20Flaring%20and%20Venting%20Report.pdf, at 6.
[891] EPA, Importance of Methane (Jun. 30, 2021), https://www.epa.gov/gmi/importance-methane (last accessed Oct. 27, 2021).
[892] EDF estimates that flaring releases 200,000 tons of methane into the atmosphere every year. EDF, Flaring Aerial Survey Results (2021), https://www.permianmap.org/flaring-emissions/ (last accessed Oct. 27, 2021).
[893] Most properly functioning flares are designed to operate at 95% efficiency, meaning that even in a best-case scenario, 5% of gas released is pure methane. *See, e.g.*, Björn Pieprzyk and Paula Rojas Hilje, *Flaring and Venting of Associated Gas*, ENERGY RESEARCH ARCHITECTURE, 12 n.3 (Dec. 2015).
[894] EDF, Permian Methane Analysis Project (2021), https://www.permianmap.org/ (last accessed Nov. 29, 2021).
[895] EDF, Flaring Aerial Survey Results (2021), https://www.permianmap.org/flaring-emissions/ (last accessed Oct. 27, 2021).
[896] *See* Attachment W at 5.
[897] *See* Attachment W at 28.
[898] *Id.*
[899] *See* Code of Colorado Regulations, Oil and Gas Conservation Commission, 2 CCR 404-1 § 903 (accessible at https://www.sos.state.co.us/CCR/GenerateRulePdf.do?ruleVersionId=9245).
[900] *See* New Mexico Administrative Code, Venting and Flaring of Natural Gas, § 19.15.27.8(A) (accessible at https://www.emnrd.nm.gov/ocd/wp-content/uploads/sites/6/Part27-FinalRule3.25.21a.pdf).

a loophole that undercuts this requirement, to reduce flaring during well completion, and to eliminate venting during production. We strongly support EPA's proposal to eliminate non-emergency venting during production, but urge EPA to strengthen its approach to flaring to ensure that its final standards achieve significant reductions in this damaging practice. In particular, we urge EPA to adopt performance standards that would eliminate the wasteful and unnecessary practice of disposing of associated gas through routine flaring. Specifically, EPA should determine that the BSER for emissions from associated gas is to capture and sell, productively use or reinject the gas. With respect to completions, we urge EPA to set performance standards that would eliminate venting throughout the flowback process except in case of narrowly-defined emergency; and eliminate flaring except in case of emergency or if necessary for pressure test purposes. Finally, in any case in which flaring does occur, EPA should require improved flare efficacy to minimize methane and other emissions.

Shifting from wasteful routine flaring to capture of associated gas would lead to significant reductions of methane, CO2, NOx, and other harmful pollutants. And gas capture is cost-effective by design: captured gas can be sold at a profit, used onsite as a fuel source, or reinjected and stored. Accordingly, a BSER requiring gas capture and productive use or storage is eminently cost-effective: in most cases, well operators capturing and selling associated gas will make a profit by selling the recovered product.[901]

### 1. *EPA's Proposal Well Completions: Eliminating Venting and Further Reducing Flaring*

EPA proposes an approach to regulating well completions based on well subcategory[902] that retains the existing requirements for completions in NSPS OOOO and NSPS OOOOa and that EPA describes in the proposal as follows. For Subcategory 1 (non-wildcat and non-delineation wells), operators must generally avoid venting, and must instead employ some method of reduced emissions completions (REC), such as (1) routing to a storage vessel, flow line, or collection system; (2) reinjection; or (3) use as an onsite fuel source, in combination with a completion combustion device.[903] Specifically, operators are directed to employ RECs first, but may flare when it is "technically infeasible to route recovered gas" using one of the methods specified

[901] *See generally* Attachment W at 11, reporting a net $3.10/mcf of natural gas profit (translating to $162 saved per/MT of methane emissions abated) when associated gas is gathered into sales lines; *see also* ICF INTERNATIONAL, Breakeven Analysis for Four Flare Gas Capture Options (Apr. 22, 2016) [hereinafter ICF INTERNATIONAL].
[902] EPA explains its well categorization as follows: "[a]s with gas wells, for well completions of hydraulically fractured (or refractured) oil wells, we identified two subcategories of hydraulically fractured wells for which well completions are conducted: (1) Nonwildcat and non-delineation wells (subcategory 1 wells); and (2) wildcat and delineation wells (subcategory 2 wells). A wildcat well, also referred to as an exploratory well, is a well drilled outside known fields or is the first well drilled in an oil or gas field where no other oil and gas production exists. A delineation well is a well drilled to determine the boundary of a field or producing reservoir." *Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources*, 81 Fed. Reg. 35824, 35845 (June 3, 2016).
[903] 86 Fed. Reg. at 63,120.

above.[904] Further, operators may vent where flaring "would present safety hazards."[905] Operators are also required to use a separator during the separation flowback period.[906]

For Subcategory 2 (exploratory and delineation wells and low-pressure wells), operators are directed to either (1) route all flowback to a completion combustion device with a continuous pilot flame; or (2) route all flowback into one or more well completion vessels, employ a separator to separate gas from oil, and combust gas.[907] Operators are not required to use a separator, however, if it is "technically infeasible" for the separator to function. Finally, venting is allowed in lieu of flaring "in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost, or waterways."[908]

We support EPA's efforts to reduce both venting and flaring during well completion, but note that the existing regulations in OOOO and OOOOa may have allowed some operators to avoid meaningful reductions by claiming that many applications of technologies or operations improvements are "infeasible." This is particularly a concern with regard to some reports of operators evading the requirement to commence operation of a separator at the beginning of flowback based on claims of technical infeasibility.[909] It is critical that EPA strengthen its well completions requirements to actually achieve the emissions reductions that have been promised (and assumed in emissions inventories) since the adoption of EPA's REC requirements in 2012.

First, we urge EPA to tighten its venting and flaring restrictions across the completion process drawing from models that have been adopted at the state level. Specifically, we propose that for both categories of wells, EPA disallow venting in all instances except when (1) emergency circumstances are present *and* (2) the operator can demonstrate that "flaring is technically infeasible or would pose a risk to safe operations or personnel safety and venting is a safer alternative than flaring."[910] EPA should limit emergency circumstances to cases of "a sudden unavoidable failure, breakdown, event, or malfunction, beyond the reasonable control of the Operator, of any equipment or process that results in abnormal operations and requires correction"[911] and that poses a danger to human safety.

Second, EPA should revise the current regulatory approach to require the operator to use REC equipment that is adequate for the particular flowback situation to control emissions from the beginning of flowback, rather than retaining the current approach. The technical infeasibility exemption has allowed operators to engage in extended periods of venting based on the

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[904] *Id.*
[905] *Id.*
[906] *Id.*
[907] *Id.*
[908] *Id.*
[909] *See* Attachment X at 11–14, as clarified by Attachment Y at 8.
[910] Wording quoted from New Mexico venting and flaring regulations, found at New Mexico Administrative Code, Venting and Flaring of Natural Gas, § 19.15.28.8 ("In all circumstances, the operator shall flare rather than vent natural gas except when flaring is technically infeasible or would pose a risk to safe operations or personnel safety and venting is a safer alternative than flaring.")
[911] Wording quoted from Colorado venting and flaring regulations, found at 2 Colo. Code Regs. 404-1 § 100 (accessible at https://www.sos.state.co.us/CCR/GenerateRulePdf.do?ruleVersionId=9245).

performance limitations of inadequate or inappropriate equipment, or without even attempting to deploy REC equipment. In the 2020 technical revisions, EPA recognized and addressed one way in which operators had been exploiting this loophole, but that was insufficient to fix the overall problem.[912]

Specifically, EPA should require *all* flowback (including what EPA now characterizes as "initial flowback") to be routed to an enclosed vapor-tight flowback vessel, as Colorado requires, or to an enclosed controlled flowback vessel, as environmental advocates and Oxy USA Inc. have proposed in New Mexico.[913] Detailed technical testimony in the New Mexico proceedings makes it clear that the purpose of deploying properly designed REC equipment is to capture and control all flowback, including the gas, from the time when flowback begins.[914] This is technically feasible, already standard practice for some companies, and does not present safety concerns.[915] The current regulatory approach of identifying an "initial flowback stage" during which gas "is not subject to control" creates a unjustified and unnecessary loophole that has been exploited in some instances to evade the overall intent to require green completions.[916]

From the flowback vessel or any connected REC equipment such as a separator, EPA should require the operator to route emissions to a gathering system, productive use, or reinjection, as the current regulations provide. EPA should not, however, include the existing exemption for technical feasibility. If there are in fact specific types of situations where the gas cannot be sold, put to productive use, or reinjected, EPA should identify and define those specific situations in the regulations, rather than defaulting to an easily misused generic characterization of technical infeasibility. We note that Colorado's rules have do not have similar, general technical infeasibility exemptions that apply during the completion process. Colorado only allows flaring during the entire completion process with prior, written approval, or "to ensure safety or during an Upset Condition for a period not to exceed 24 cumulative hours."[917] If operators need to flare longer than 24 hours due to an upset, they must seek regulatory approval to continue.[918]

Under Colorado and New Mexico rules, flaring is also permitted in pre-approved cases during pressure testing.[919] EPA may choose to provide some kind of accommodation for pressure testing, although pressure testing without flares is possible, and the technology for this practice currently

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[912] In the 2020 technical revisions, EPA clarified that the requirement to use a separator during flowback meant a separator designed to accommodate completion flowback, regardless of whether it was a production separator. This change prevented operators from continuing to decline to use a separator during flowback on the grounds that it was technically infeasible for a smaller production separator onsite to handle completion flowback rates. *See* 85 Fed. Reg. 57398 at 57403 (Sept. 15, 2020).
[913] 5 Colo. Code Regs. 1001-9 V.D.1.a.; *see also* Attachments X and Z.
[914] *See* Attachment AA at 4–10 (and supporting exhibits).
[915] *Id.*
[916] *Id*. See in particular 5 Colo. Code Regs. § 1001-9 Part F (Statements of Basis, Specific Statutory Authority and Purpose), Section T: September 17–18 & 23, 2020, Oil and gas operations (Part D), "Flowback Vessels."
[917] 2 Colo. Code Regs. 404-1 § 903(c)(3).
[918] *Id.* at § 903(c)(3)(C).
[919] *See* 2 Colo. Code Regs. 404-1 § 903(d)(1)(B),(E) (allowing venting or flaring "during and as part of active and required maintenance and repair", and "during a Bradenhead test…"); New Mexico Administrative Code, Venting and Flaring of Natural Gas, § 19.15.27.8(D)(4)(c),(i) (allowing venting or flaring during "repair and maintenance" and "a bradenhead test").

exists.[920] Finally, we urge EPA to impose monitoring and reporting requirements for all instances of flaring during completion operations.

### 2. *Production: Eliminating Routine Flaring of Associated Gas*

EPA's proposed rule for associated gas during oil well production eliminates non-emergency venting, but does not eliminate or effectively reduce flaring. Specifically, the proposed standards define "affected facility" as each oil well that produces associated gas, and require associated gas to be routed to a sales line if access to such is "available."[921] If access is not available, however, gas can be used as an onsite fuel source; used for another useful purpose that a purchased fuel or raw material would serve; or flared, so long as the flare results in at least a 95% percent reduction in methane and VOC emissions.[922]

We strongly support EPA's proposal to eliminate non-emergency venting. However, as proposed, the rule would allow operators to avoid any meaningful reductions in flaring emissions because it allows operators to flare in all instances in which a sales line is deemed unavailable. This effectively–and unsupportably–amounts to a finding that routine flaring of associated gas is the BSER for well production emissions. Notably, the RIA for the proposed rule does not attempt to assess the regulatory impacts of this approach because it asserts that they are "small relative to the impacts of the rest of the proposal."[923] This is an implicit recognition that the proposed approach is not projected to meaningfully reduce emissions from associated gas. In short, while we agree with EPA's definition of affected source, EPA must significantly strengthen its proposal and determine that the BSER for associated gas at oil wells is to capture and route emissions to a sale line, to use it on-site for a productive purpose, or to preserve it through re-injection. Accordingly, EPA should require these practices and carefully delineate when exemptions may apply, such as in cases of emergency.

As we discuss below, capture alternatives are widely available and EPA should ensure that operators are deploying them to minimize emissions from associated gas.. In developing our recommendations below, we utilize a variety of sources, including a new report by Rystad Energy, which we have submitted along with these comments, that provides a thorough analysis of flaring and of the costs and benefits of various gas capture approaches.[924]

#### a. Routine Flaring is Not an Environmentally or Economically Acceptable Way to Handle Associated Gas.

While many types of gas flaring are unnecessary, polluting, and wasteful, "routine flaring" of associated gas is especially egregious due to its massive scale and lack of justification. The World Bank's *Zero Routine Flaring by 2030 Initiative* provides a widely accepted definition of "routine

[920] *See, e.g.*, SCHLUMBERGER, ZERO FLARING WELL TEST AND CLEANUP, https://www.slb.com/reservoir-characterization/reservoir-testing/zero-flaring-well-test-and-cleanup.
[921] 86 Fed. Reg. at 63,120.
[922] *Id.*
[923] RIA at 2-7.
[924] *See generally* Attachment W.

flaring:" "flaring that occurs during the normal production of oil, and in the absence of sufficient facilities to utilize the gas on-site, dispatch it to a market, or re-inject it."[925] This definition recognizes that routine flaring is a means of disposing of associated gas on an ongoing basis by destroying it without obtaining any use from the resource. The definition expressly recognizes that routine flaring is less desirable than "utiliz[ing] the gas on-site, dispatch[ing] it to a market, or re-inject[ing] it." The World Bank began the *Zero Routine Flaring by 2030 Initiative* in 2015 in recognition that the practice of routine flaring by oil producers around the world results in massive GHG emissions and waste of valuable resources; is not necessary for oil production; is disfavored by the industry; and is an outdated practice that many oil producers are willing to phase-out voluntarily.

In the United States, routine flaring causes substantial air pollution and other environmental harms. Routine flaring releases vast quantities of CO2, VOCs, and black carbon directly into the atmosphere,[926] in addition to hundreds of thousands of tons of methane emissions.[927] Nearly 600 million cubic feet of associated gas was flared every day in 2021.[928] This was down from a peak of over 1.1 million cubic feet per day in 2019–much of the decline was due to the COVID 19 pandemic and reduced demand allowing infrastructure to catch up to production, as well as some ongoing reduction in flaring intensity driven by voluntary efforts by some operators and regulations in states like Colorado and New Mexico.[929]

Recent research by Rice University scientists quantifies the toll from one pollutant – black carbon particulate matter – from flaring in the United States on human health. The researchers estimate that this pollutant from this single source killed 26 – 53 Americans in 2019, while numerous others suffered other negative health impacts, such as the onset of childhood asthma.[930]

It is also important to recognize the particular burden routine flaring imposes upon nearby communities, who must live alongside often massive, bright, noisy, and highly polluting flares operating constantly for months or years at a time. The locations and impacts make routine flaring an important environmental justice issue. A 2021 study published in *Environmental Research Letters* found that in the three basins accounting for 83% of all flaring activity, half a million

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[925] THE WORLD BANK, ZERO ROUTINE FLARING BY 2030 (ZRF) INITIATIVE: FREQUENTLY ASKED QUESTIONS AND ANSWERS, https://www.worldbank.org/en/programs/zero-routine-flaring-by-2030/qna#:~:text=What%20does%20%22routine%20flaring%22%20mean,dispatch%20it%20to%20a%20market (last accessed Jan. 27, 2022) [hereinafter WORLD BANK: FREQUENTLY ASKED QUESTIONS AND ANSWERS].
[926] Gvakharia et al., *Methane, Black Carbon, and Ethane Emissions from Natural Gas Flares in the Bakken Shale, North Dakota*, ENVIRONMENTAL SCIENCE & TECHNOLOGY 5317, 5317 (2017) (accessible at: https://ngi.stanford.edu/sites/g/files/sbiybj14406/f/acs.est_.6b05183.pdf).
[927] EDF, Flaring Aerial Survey Results (2021), https://www.permianmap.org/flaring-emissions/ (last accessed Oct. 27, 2021).
[928] *See* Attachment W at 20.
[929] *See id.*
[930] *See* Attachment BB.

people live within 5 kilometers of a flare, and 39% of these live near more than 100 nightly flares.[931] Of these, people living nearest to flares were more likely to be people of color.[932]

Routine flaring not only endangers communities, it is also an enormously wasteful practice: in 2019, well operators in the United States vented flared approximately 1.48 billion cubic feet (bcf) per day of gas[933]–enough to meet 25% of the country's home heating needs for a year.[934]

The oil and gas industry itself has recognized that routine flaring can and should be avoided. 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."[935] As of 2022, there are 51 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.[936] Another industry group, the Texas Methane and Flaring Coalition, consisting of seven state trade associations and over 40 Texas operators, has stated that "The Coalition agrees we should strive to end routine flaring…."[937]

Finally, 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 emergencies, certain maintenance activities, and pursuant to a one-time, time-limited advance approval by the regulator under specified conditions.[938] New Mexico adopted regulations in March 2021 that similarly prohibit venting and flaring during production, except under specified circumstances that do not encompass routine flaring.[939] In addition, 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.[940]

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[931] Cushing et al., *Up in Smoke: Characterizing the Population Exposed to Flaring From Unconventional Oil and Gas Development in the Contiguous U.S.*, 16 ENVIRONMENTAL RESEARCH LETTERS 1, 1 (2021), https://iopscience.iop.org/article/10.1088/1748-9326/abd3d4/pdf.
[932] *Id.* at 7.
[933] EIA, NATURAL GAS VENTING AND FLARING IN NORTH DAKOTA AND TEXAS INCREASED IN 2019 (Dec. 8, 2020), https://www.eia.gov/todayinenergy/detail.php?id=46176 (last accessed Jan. 28, 2022).
[934] *See* EIA, NATURAL GAS EXPLAINED: USE OF NATURAL GAS (Dec. 7, 2021), https://www.eia.gov/energyexplained/natural-gas/use-of-natural-gas.php (last accessed Dec. 16, 2021).
[935] WORLD BANK FREQUENTLY ASKED QUESTIONS AND ANSWERS.
[936] THE WORLD BANK, ZERO ROUTINE FLARING BY 2030 (ZRF): ABOUT THE "ZERO ROUTINE FLARING BY 2030" INITIATIVE, https://www.worldbank.org/en/programs/zero-routine-flaring-by-2030/about (last accessed Jan. 27, 2022) [hereinafter WORLD BANK: ABOUT THE "ZERO FLARING BY 2020" INITIATIVE].
[937] TEXAS METHANE AND FLARING COALITION, FLARING RECOMMENDATIONS AND BEST PRACTICES, 2 (June 16, 2020).
[938] 2 Colo. Code Regs. 404-1 § 903d.
[939] New Mexico Administrative Code, Venting and Flaring of Natural Gas, § 19.15.27.8(A).
[940] Alaska Administrative Code, 20 AAC § 25.235.

3. *Productive Uses of Gas are Widely Available, Cost-Effective, and Capable of Addressing Root Causes of Routine Flaring Across All Geographies, Situations and Well Types.*

a. Causes of Routine Flaring

In the preamble to the proposed rule, EPA notes some but not all of the most common drivers of routine flaring, while it does not discuss this topic at all in the TSD. Yet understanding the reasons why some operators currently routinely flare associated gas is critical to understanding the options for addressing this practice and the emissions it produces.

One common reason for routine flaring, particularly at older wells with lower flow rates and pressures, is that the gas is produced by the well at insufficient pressure to access an available gathering line. This constraint is something over which operators have full control and which they are used to handling as a normal part of operations. Operators can and, particularly when flaring is restricted, commonly do add one or more compressors to boost pressure and put the gas into the line. While the operation of the compressor will produce some emissions, they are generally a small fraction of those that would have resulted from flaring the gas instead.

Another common reason for routine flaring is that an otherwise available gathering line may be at maximum capacity.[941] As new hydraulically fractured wells are brought online, they typically produce very high volumes of gas that then rapidly decline over the first few months to a year of the well's operation. Depending on the timing of well development, a line with ample capacity on average over time may be temporarily capacity-limited at times. Operators can coordinate with the gathering system operator and schedule the beginning of well production to spread the peak production from multiple wells over time and avoid either being unable to access the line or bumping the lower producing wells off the line. Again, this solution is within control of operators. It will also generate additional revenues for the operator and midstream company by avoiding wasted product, which gives midstream companies a direct incentive to help operators avoid the need to flare by maximizing average gas flow through the gathering system over time.

In some instances, however, nearby gathering lines operate at maximum capacity on an ongoing basis, and in response, operators simply routinely flare at a very low cost.[942] Yet this does not mean that gathering capacity is only available if an operator builds it themselves or pays the full cost. Rather, this type of a resource constraint is precisely what markets exist to solve in an efficient manner. If routine flaring is no longer allowed for disposal of associated gas, operators would presumably be willing to pay somewhat higher prices for access to take-away capacity. This price signal would prompt the highest-value wells to maintain access to the gathering system, while midstream operators build out additional capacity (presumably for a net profit over time, as this is their business model) and/or make adjustments to allow existing lines to operate at higher pressures and capacities. At the same time, lower-value wells can defer completions, shut in temporarily, and/or deploy other means of putting the gas to productive use (as discussed below).

[941] *See* Attachment W at 34.
[942] *See id.* at 34.

Rarely, routine flaring occurs because the operator is beginning production in a new geographic area that does not have a gathering system already in place.[943] But here, before the well is drilled and completed, it is the operator itself that has the relevant information about the timing and expected quantities of gas. The operator can share this information with midstream companies well in advance of developing the new field, assuring those companies of sufficient gas supply and giving them time to build out a gathering system. Operators can also make arrangements for other methods of gas capture, such as trucking. In any event, the lack of a gathering system in place prior to production is not the main cause of routine flaring. Even in the Baaken, which has been developed far more recently, Rystad identifies distance from infrastructure as the driver for just 1% of flared associated gas.[944]

Finally, routine flaring also occurs when large maintenance projects take capture and sale infrastructure, such as portions of a gathering system or a processing plant, offline for a period of time. But absent an emergency situation, the downstream facility usually plans such projects and provides notice to upstream producers. This gives producers time either to arrange other temporary means of gas transport to processing plants, such as CNG trucking, or allows them to shut in the wells temporarily.

a. Best Practices Commonly Deployed to Capture the Value of Associated Gas

This section expands upon and clarifies the TSD's discussion of control options for emissions of associated gas, which does not accurately and fully describe the available options. The question for EPA in this rulemaking is not whether operators do or do not have practical means of avoiding routine flaring – it is *whether those means are available at a reasonable cost*.[945] The answer is yes, as we discuss in further detail below. Specifically, this section describes four gas capture alternatives: (1) routing to a sales line; (2) compressing (or liquifying) the gas on site and transporting by truck for sale; (3) reinjecting the gas; and (4) using the gas to meet energy needs on site. Operators also can delay production start up at new wells and choke or shut in existing wells during periods when downstream gathering or processing capacity is temporarily unavailable. Shutting in wells has been observed to have little effect on the ultimate productivity of the well.[946] As the experience of better performing operators, state regulatory findings, and extensive analyses by Rystad Energy and others show, these approaches are both broadly available and affordable.[947]

***Routing to a Sales Line.*** Currently, the majority of associated gas is captured and transported by sales line, and this will likely continue to be the preferred approach of most operators. When new wells are drilled in the vicinity of existing gathering systems, they can be quickly and cheaply

[943] *See id.* at 35 ("Lack of infrastructure access is not the issue, timing and capacity is").
[944] *Id.*
[945] 42 U.S.C. 7411(a)(1); *see also Costle*, 657 F.2d at 326, 343, 346-7, *Lignite Energy Council v. EPA*, 198 F. 3d 930, 933 (D.C. Cir. 1999), *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973), and *Portland Cement Ass'n v. EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975)).
[946] Attachment W at 80.
[947] *See generally* Attachment W.

connected to the existing system.[948] The Rystad report shows that connecting wells to gathering line infrastructure is not only highly cost-effective but actually profitable for operators, with an average net negative cost of $3.10 per thousand cubic feet (mcf).[949]

As a general practice, EPA's determination of the BSER for controlling emissions from an affected facility is informed by its analysis of the control options for that emissions source. While EPA recognizes that routing gas to a sales line is a highly attractive option for operators, the TSD does not accurately describe the availability of this option, which is a critical shortcoming for purposes of determining BSER. The TSD assumes that "access to a sales line" either is or is not available to an operator, without the operator having any ability to influence such availability, much less ensure it. Because gathering systems and natural gas processing capacity are more commonly owned by midstream companies, rather than the producers themselves, and because many of the options for avoiding routine flaring are not plug-and-play control technologies (unlike installing a compressor, which is exactly such a solution in the case of insufficient wellhead pressure), there has been a tendency to view the availability of infrastructure necessary for capture and sale as largely outside of producers' control. This is, indeed, how access to a sales line is treated in the TSD. But this key foundational assumption is not reality; nor is it the prevailing practice among producers that are successfully curtailing routine flaring.[950] The vast majority of routine flaring is fundamentally driven by business decisions, not technical constraints. The practical reality is that operators have substantial and relatively low-cost or negative-cost opportunities to ensure access to take-away capacity for their associated gas.

First, it is worth noting that the oil and gas industry exists to produce and sell their products – their business model depends on getting these products to market. The United States has billions of dollars in infrastructure in place dedicated to producing, gathering, processing, transporting and delivering natural gas. Investment in this infrastructure responds to the market demands of oil and gas producers and suppliers. Operators of *gas* wells know how to ensure that they can capture and route gas for sale. They derive their revenues predominately from natural gas, and while there are some wasteful practices, they do not engage in routine flaring. These operators make sure that the wells are connected to gathering lines with available capacity prior to bringing those wells into production, and when downstream facilities are not operating for extended periods of time, gas wells are commonly temporarily shut in.

Routine flaring of associated gas is widespread not because gas from an oil well has a different value than gas from gas wells (although prices do vary somewhat by location),[951] but because of the comparative values of gas and oil. Oil has such a higher relative value than gas in recent years that many oil well operators optimize for oil production to the point of treating the associated gas as a waste product. Nevertheless, because associated gas does, in fact, have economic value, capturing it for sale typically has net negative costs.[952] Even in a situation where an operator might

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[948] *Id.* at 43.
[949] *Id.* at 11.
[950] *See* Attachment W at 79-80, noting that operators reducing routine flaring are negotiating contracts that ensure or incentivize midstream operators to provide firm capacity.
[951] *See, e.g.*, *id.* at 43-44, 78.
[952] *See id.* at 11, finding that gas gathering, on average, has a net profit of $3.10/kcf or $162 per metric ton of methane flaring avoided.

not be able to ensure access to gathering capacity without incurring some net costs, those costs are likely to be modest overall even before (and certainly after) offsetting the value of the gas.[953] This is quite different from a typical pollution control requirement that imposes only costs.

Second, as the Rystad report makes clear, operators can make operational and commercial adjustments to improve or ensure their access to a gathering system (as well as make alternative arrangements for periods of unavailability).[954] For example, operators can provide information to midstream companies in advance about expected timing and quantities of gas production, allowing gathering system operators to expand capacity in a timely manner. Operators can require that their new wells are connected to a gathering system with available capacity prior to beginning production.[955] They can also enter into contractual arrangements that guarantee firm gathering or trunkline capacity, and/or that penalize midstream gatherers and processors for downtime.[956] There are some costs to coordination, information sharing, and negotiating and paying for contractual guarantees, but by and large these should be quite small compared to typical hardware-based pollution control investments. Regardless, these options make it clear that operators commonly have substantial control over their access to gathering capacity and can exercise this control at typically net negative costs to avoid routine flaring.

***Truck Transport.*** In cases where existing well sites lack adequate existing gathering system infrastructure, or where gathering systems are at capacity on a temporary or ongoing basis, well operators may choose to forego construction of additional gathering capacity or coordination with third-party gatherers and instead convert associated gas onsite into compressed natural gas (CNG)[957] and transport it by road in specialized tanker trucks.[958] The trucks would transport the gas to processing plants, where the gas is prepared to meet pipeline requirements.[959] Trucking can be both a long-term option for existing wells lacking adequate gathering line infrastructure or capacity, and a short-term solution in cases of low capacity due to outages, maintenance activities, or temporary system overload—either at the processing plant (in which case trucks could transfer the gas to an alternative plant) or on the gathering system (in which case the trucks can bypass the initial pipelines and transfer the gas directly to the plant).[960]

A report from the New Mexico state Methane Advisory Panel, specifically examining CNG trucking, found that CNG trucking is a "portable, scalable and low or negative cost" approach to

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[953] *See id.* at 39 (citing costs of $42/MT of methane flaring avoided prior to offsetting with gas sales).
[954] *See id.* at 45.
[955] *See id.* at 80.
[956] *See id.*
[957] As discussed in the Rystad report, *see generally* Attachment W at 10–11. LNG trucking is another option for gas transport. However, at this time we lack adequate data on overall emissions associated with LNG trucking to determine whether this would be an appropriate approach to emissions mitigation.
[958] *See* Anders Pederstad, Martin Gallardo, and Stephanie Saunier, IMPROVING UTILIZATION OF ASSOCIATED GAS IN US TIGHT OIL FIELDS, CARBON LIMITS AS (Prepared for Clean Air Task Force) (Oct. 2015), https://www.catf.us/wp-content/uploads/2015/04/CATF_Pub_PuttingOuttheFire.pdf at 33 [hereinafter CARBON LIMITS].
[959] *See id.*
[960] *See, e.g.*, Pederstad et al. *supra* note 30, at 33.

gas capture.[961] Indeed, as noted above, in many cases truck transport ultimately presents little or no additional cost to well operators because operators will incur only minimal net costs or achieve net benefits by reselling the gas. Various factors play into the total expense of a trucking operation, including distance traveled. The New Mexico report, for instance, found that trucking is most efficient when well sites are within 20-25 miles of a processing plant.[962] For CNG, operators must purchase an onsite compressor, the total one-time cost of which can be approximated at $200,000 for the equipment and $50,000 for the installation.[963] Operators will also need to pay the truck drivers, and may need to lease the appropriate trucking assembly.[964]

Analysis by ICF International reports that the quantities of gas transport needed for CNG trucking to break even as a method of gas capture—considering the costs of the onsite compressor, equipment lifetime, truck fuel, driver salary, and several other factors—range from 134 mcf to 345 mcf of captured gas per day, depending on gas prices.[965] Importantly, this total volume need not be collected from a single well: instead, operators may capture gas from multiple wells in the same vicinity.[966] For particularly high producing wells, then, CNG trucking will constitute a net benefit for operators. And overall, the net costs are reasonable in terms of methane emissions abatement: Rystad's report finds that on average, CNG trucking will cost operators $1.8/kcf, or $94 per MT of methane flaring avoided.[967]

***Reinjection.*** In some circumstances, well operators may prefer to reinject associated gas. Reinjection is used widely in Alaska, where 90% of associated gas is injected into oil-bearing formations.[968] Reinjection as a method of gas capture has significant emissions reduction benefits, because it largely eliminates emissions of methane and other pollutants.[969]

Operators choosing to reinject associated gas may do so either by drilling a new injection well or by reappropriating an existing inactive production well.[970] Shale reservoirs are particularly well

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[961] *See* NEW MEXICO ENVIRONMENT DEPARTMENT & NEW MEXICO ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT: METHANE ADVISORY PANEL (2019), https://www.emnrd.nm.gov/ocd/wp-content/uploads/sites/6/OCD-Exhibit6-NMENRDNMED-MethaneAdvisoryPanel-Technical-Report.pdf [hereinafter METHANE ADVISORY PANEL] at 178. In March of 2021, the state of New Mexico joined Colorado in implementing regulations which banned flaring except in limited circumstances. *See generally* New Mexico Administrative Code, Venting and Flaring of Natural Gas, § 19.15.27.8(A) (accessible at https://www.emnrd.nm.gov/ocd/wp-content/uploads/sites/6/Part27-FinalRule3.25.21a.pdf).
[962] *See* METHANE ADVISORY PANEL at 173, 178.
[963] *See* ICF INTERNATIONAL at 4.
[964] *See id.*
[965] *See* ICF INTERNATIONAL at 9.
[966] *See id.*
[967] Attachment W at 39. Rystad further finds that LNG trucking will cost $5.6/mcf, or $292 per MT of methane flaring avoided. *Id.*
[968] *See* EIA, *Natural Gas Weekly Update: Alaska Natural Gas Infrastructure* (May 27, 2021), https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2021/05_27/ (last accessed Dec. 15, 2021).
[969] *See* Fengshuang Du and Bahareh Nojabaei, *A Review of Gas Injection in Shale Reservoirs: Enhanced Oil/Gas Recovery Approaches and Greenhouse Gas Control*, MDPI: ENERGIES (June 19, 2018), https://www.mdpi.com/1996-1073/12/12/2355 at 25.
[970] See SADIQ J. ZARROUK & KATIE MCLEAN, "Geothermal Wells", in GEOTHERMAL WELL TEST ANALYSIS, 39-61, 54 (2019) ("Geothermal reinjection wells [including gas reinjection wells] are generally

suited to injection because of their large storage capacity: "nanopores" in the rock formation can trap and store greenhouse gasses in an absorbed state.[971] Associated gas may also be injected and stored in natural aquifers, which may be suitable for gas storage when the sedimentary rock formation is overlaid with impermeable "cap" rock,[972] or in salt caverns.[973] Reinjection costs vary depending on various factors, but Rystad finds that on average, costs are $3.4/mcf, and $177 per MT of methane flaring avoided.[974]

***Use Onsite as a Fuel Source or Gas-to-Wire.*** In addition to the various methods of gas capture and redirection explored above, well operators can use associated gas for power needs on site, and implement a gas-to-power system for local loads.[975] For wells that are not yet connected to the power grid, on-site gas-to-power technology can replace the diesel generators that would otherwise be used to power operations.[976] This is very beneficial from an emissions perspective, since diesel is a highly polluting fuel with elevated levels of nitrogen oxides, particulate matter and toxic pollutant outputs.[977] It can also provide significant cost saving, because purchasing and transporting fuel from offsite carries a significant cost. As a result, Rystad reports that fully displacing diesel with associated gas for power demand at the well amounts to $7-$10/mcf saved–subtracting the cost of power generator and treatment and assuming 50 mcf per day of power used.[978]

Thus, operators can significantly reduce both costs and emissions by utilizing available associated gas to meet well pad energy needs. And they can make a profit while doing so: Rystad estimates that on average, on-site use of gas nets a profit of $8.60/mcf.[979] This makes it a compelling alternative to routine flaring and an appropriate element of the BSER for reductions of associated gas at oil wells.

Another option is to use the associated gas to power a small electricity generation plant that sends power to the grid.[980] This approach depends on an ongoing supply of a relatively large quantity of gas to make the necessary investments worthwhile, so it is not suitable for every application.[981] But where the gas volumes and grid access are available, it can also be a net negative cost option.[982]

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designed and drilled to the same standards as production wells. In some fields, reinjection wells have been converted to production wells and vice versa.")

[971] Du and Nojabaei at 25. *See also* Yuan Chi , Changzhong Zhao, Junchen Lv, Jiafei Zhao and Yi Zhang, *Thermodynamics and Kinetics of CO2/CH4 Adsorption on Shale from China: Measurements and Modeling*, MDPI: ENERGIES (Mar. 13, 2019) at 1.

[972] *See* EIA, *The Basics of Underground Natural Gas Storage* (Nov. 16, 2015), https://www.eia.gov/naturalgas/storage/basics/ (last accessed Jan. 27, 2022).

[973] *See id.*

[974] Attachment W at 69.

[975] Pederstad et al., *supra* note 30, at 38.

[976] *Id.* at 36. *See also* Attachment W at 51.

[977] *See* EPA, ABOUT DIESEL FUELS (last accessed Dec. 17, 2021), https://www.epa.gov/diesel-fuel-standards/about-diesel-fuels.

[978] Attachment W at 51.

[979] *Id.* at 11.

[980] *Id.* at 72.

[981] *See id.*

[982] *See id.*

b. Best Practices to Capture the Value of Associated Gas are Broadly Available

As the Rystad report conveys in detail, at least one or more of the best practices for gas capture and sale, productive use, or reinjection described above are broadly available to operators at a reasonable cost in every basin and at every production level.

First, routing gas to gathering lines for sale is very broadly available to operators. As Rystad notes, this approach is proven, ubiquitous, scaleable, and relatively quick to deploy.[983] As 95% of associated gas produced in the U.S. is currently not being flared, most of this captured gas is presumably being sent to sale through gathering infrastructure.[984] Not only is the vast majority of associated gas routed to gathering lines, but of the quantities that are flared instead, "the vast majority of flaring is from wells that are hooked up to [infrastructure]" at some point in the wells' life.[985] Further, Rystad's analysis shows that a relatively small number of wells are responsible for a large proportion of total flaring across each of the states.[986] This ranges from 3% of the wells contributing 83% of the flaring in Colorado, to 16% of the wells contributing 77% percent of the flaring in North Dakota, and totals 7% of the wells contributing 70% of the flaring on average.[987] This means that in every state analyzed, the majority of wells, and likely the great majority of wells, are already capturing gas and routing it to gathering lines.

With the exception of Colorado, infrastructure access (as opposed to capacity) was identified as the constraining factor for capture for 3% or less of the total gas volumes flared, and upcoming compliance with Colorado's routine flaring prohibition will necessarily address the issues there.[988] Finally, for the very small proportion of associated gas production where infrastructure access (i.e., distance from gathering infrastructure) is identified as the key constraint, other transport, on-site use, and reinjection options are available at potentially somewhat higher but still reasonable costs.[989]

A system of emissions reduction that is already used by the majority of operators for the vast majority of associated gas, mostly because it has net negative costs, is the epitome of a broadly available and highly affordable solution. The fact that there are instances where operators have not already found it worthwhile to capture gas only means that in some cases there will be small net costs to this pollution control system, not that sale, productive use, or reinjection of associated gas is not an available approach. While the Rystad report identifies challenges and some constraints to deploying each of these approaches, they are clearly almost never prohibitive for gas gathering. In addition, CNG and reinjection, the two capture approaches that Rystad identifies as

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[983] *Id.* at 43.
[984] *Id.* at 21.
[985] Attachment W at 78.
[986] While Rystad's in-depth analysis did not look at flaring in every state, it included all five states with detailed flaring disclosure data, which are responsible for roughly 90% of total onshore gas flaring in the U.S.: Texas; North Dakota; New Mexico; Colorado; and Wyoming. *Id.* at 6.
[987] *Id.* at 27.
[988] *Id.* at 78.
[989] *See generally* Pederstad et al., *supra* note 30; Attachment W at 38-76.

the next most promising options, have different, non-overlapping constraints. This makes them independent alternatives, and at least one if not both should be available to most of the wells where routing to gathering is temporarily unavailable (due to, e.g., downstream outages) or is long-term cost-prohibitive (due to distance from infrastructure). Overall, the breadth of availability and the very reasonable costs of the options more than satisfy the criteria to find capture and sale, productive use or reinjection the "best system."

### 2. *BSER, Performance Standards, and Monitoring Requirements*

#### a. "Definition of Affected Facility"

For the purpose of reducing emissions from associated gas, EPA proposes to define the affected facility as each oil well that produces associated gas. We support this approach, as it appropriately recognizes that each well with associated gas would produce large emissions absent proper disposition of the gas. We believe that any such productive use, sale, or preservation of the associated gas' value should be included in the BSER as acceptable options to replace routine flaring.

EPA also requests comment on an alternative approach that would define the affected facility as each oil well that produces associated gas and does not route the gas to a sales line. We understand that an approach along these lines may be intended to create incentives for operators to connect to sales lines in the first instance. However, such an approach will very likely not operate as intended and could create unnecessary confusion. A substantial portion of routine flaring occurs at sites that are already connected to sales lines. Under EPA's proposed alternative definition, a site could periodically fluctuate between being identified as affected and not, depending on whether it is routing gas to the sales line at any given moment.

This alternative definition would also limit the site's ability and obligation to consider other solutions that would minimize the causes of its flaring. For example, a site may be connected to a sales line to which it normally routes gas, but flare during an extended period of downstream maintenance at the processing plant. The site would initially not be an affected facility, but would then become an affected facility with an obligation to avoid the contemplated routine flaring. Then, if the well temporarily shut in or converted the gas to CNG and trucked it to another processing plant, the facility would once again no longer be an affected facility. This seems unnecessarily complex and could lead to confusion on the part of operators, without providing any meaningful incentive to the facility to route gas to the capture line.

#### b. Clarifying Meaning of "Access to a Sales Line"

EPA requests comment on how best to define the term "access to a sales line."[990] Allowing operators to make flaring decisions based on "access to" or "availability of" a sales line could allow operators to avoid gas capture whenever existing pipeline infrastructure is not already in

[990] 86 Fed. Reg. at 63,183.

place. Operators could similarly attempt to avoid gas capture if existing infrastructure lacks capacity, or even if sufficient infrastructure has available capacity, but the operators have failed to coordinate or contract with the gathering system to ensure access or simply not installed a compressor needed for the gas to access the line. We therefore strongly urge EPA to abandon this unworkable framing, and instead adopt a BSER that would eliminate routine flaring by requiring capture and sale, productive use, or storage of associated gas except in specific narrowly defined circumstances.

c. Capture and Sale, Productive Use or Storage of Associated Gas is the Appropriate BSER

EPA's proposal correctly states that "BSER is routing associated gas from oil wells to a sales line" for disposing of associated gas.[991] EPA should broaden this determination, however, and find that capturing and routing associated gas to any productive use or reinjection of the gas is the BSER. Specifically, we urge EPA to find that BSER for reducing methane and VOC emissions from associated gas venting at oil well sites is to capture and route the associated gas to any productive use including: sell the gas, use it as an onsite fuel source, use it for another useful purpose that a purchased fuel or raw material would serve, or reinject the gas.

Each of these options essentially eliminates the methane and VOC emissions that would occur if the gas were vented. Routing for sale or on-site use would still result in some combustion-related (or in the case of use for plastic production, production-related) emissions from onsite or downstream use. However, EPA should be able to determine that putting these quantities of associated gas to productive use would displace some other gas production and use, resulting in largely eliminating net emissions compared to flaring of associated gas, which displaces no gas production and provides no other additional use. Reinjection, meanwhile, avoids almost all of the emissions from venting or flaring, and thus should also be considered an element of the BSER.

In contrast, routine flaring to dispose of associated gas is a practice that: emits hundreds of thousands of tons of GHGs per year, in addition to VOCs, black carbon and toxic air pollution; many wells avoid altogether; the industry itself has recognized should be phased out; two major oil and gas producing states have already prohibited; and has widely available and commonly deployed technologically and economically viable alternatives, as outlined above. EPA estimates that flaring gas as a means of disposal would only reduce CO2e emissions by roughly 81%, which allows massive volumes of GHG emissions to continue and without obtaining any benefits from use of the gas. An emissions control approach that results in substantially less emissions control than the alternatives while wasting the product rather than putting it to productive use cannot qualify as the "best system of emission reduction" for reducing emissions from associated gas. (See Section III.A above for a full discussion of EPA's authority under section 111, including the criteria that govern EPA's determination of what constitutes the BSER.)

Under section 111, EPA must translate its BSER determination into a quantitative emission limitation. Performance standards issued by EPA (for new sources) or states (for existing sources)

[991] *Id.* at 63,237.

must be consistent with that federally-designated emission limitation.[992] If such a numerical limitation is not feasible, EPA may impose a design, equipment, work practice, or operational requirements as described in section 111(h). With regard to the BSER for associated gas from oil wells, EPA could take various approaches to establishing either a numerical limitation or a work practice or operational requirement.

A straightforward approach is to set work practice and operational requirements under which associated gas, on an ongoing and continuous basis and without the use of any other method of disposal, must be routed to a sales pipeline or otherwise transported for sale, put to productive use on-site, or reinjected. EPA could further define "productive use" as "significantly using either the pressure energy or chemical energy of the gas for useful work." EPA might need to clarify that flaring could still be used to dispose of associated gas under specified narrowly and precisely defined circumstances, such as to avoid venting during emergencies, or short-term maintenance activities involving small quantities of gas. EPA would further need to define what constitutes an "emergency," as discussed above.

Another possibility would be for EPA to set a numeric requirement of zero for emissions from the routine disposal of associated gas as a waste product through flaring. This approach would also require EPA to carefully delineate the types or instances of flaring of associated gas that would not be considered "routine disposal" or "routine flaring." Any flaring not so delineated should be considered to be routine flaring and thus subject to a zero-emissions requirement.

Under either approach, EPA should delineate types of flaring that are not considered routine in a manner that ensures that total emissions from non-routine flaring (as defined by EPA according to specific narrowly-defined circumstances) would be very small. Analysis conducted for EDF by Rystad finds that, on average, a small amount of "safety" flaring will be necessary in cases of emergency, and operators should be permitted to maintain a continuous pilot flame to allow for emergency flaring.[993] Rystad further determines, however, that flaring above a maximum of 0.2% of gas is unnecessary and excessive.[994]

Finally, as in the case of well completions, venting during production should be disallowed in all circumstances *except* when (1) emergency circumstances are present and (2) the operator can demonstrate that "any other alternative is technically infeasible or would pose a risk to safe operations or personnel safety, and venting is the safest available option."[995] Again, emergency

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[992] In contrast to new sources, which EPA directly regulates under section 111(b), existing sources are subject to performance standards that states establish in plans adopted under section 111(d). These state plans must be consistent with EPA's emission guideline, which includes a federally applicable emission limitation. To that end, state-issued performance standards for existing sources must be "no less stringent" than the emission limitation included in EPA's guideline. 40 C.F.R. § 60.24a(c).

[993] Attachment W at 31.

[994] *Id.* The Rystad study notes that Norway, the Netherlands, and Colorado, all of which have banned routine flaring, exhibit amounts of flared gas (as a percent of all of gas produced) at or below 0.2%.

[995] Compare wording from New Mexico venting and flaring regulations, found at New Mexico Administrative Code, Venting and Flaring of Natural Gas, § 19.15.28.8 ("In all circumstances, the operator shall flare rather than vent natural gas except when flaring is technically infeasible or would pose a risk to safe operations or personnel safety and venting is a safer alternative than flaring.") Again, emergency circumstances should be found only in case of "a

circumstances should be found only in case of "a sudden unavoidable failure, breakdown, event, or malfunction, beyond the reasonable control of the [o]perator, of any equipment or process that results in abnormal operations and requires correction" and that poses a danger to human safety. Lack of available pipeline capacity should not be accepted as an instance of emergency.

d. EPA Should Establish an Identical BSER for Emissions of Associated Gas from New and Existing Wells

EPA should establish an identical "best system" for emissions of associated gas from new and existing wells under OOOOc and OOOOd. Both new and existing wells can avoid the emissions from routine flaring by capturing and either selling, using, or reinjecting associated gas at a reasonable cost. As a general matter, operators have flexibility to plan ahead to avoid routine flaring at new wells, which could lower compliance costs to some degree for new wells in comparison to existing wells. On the other hand, the additional lead time for applying regulatory requirements to existing wells would increase their flexibility and lower their relative costs. On the whole, there is nothing that prevents existing wells from pursuing each of the options for capture and sale, use or reinjection described above at costs comparable to those for new wells (except for delay of production start-up, for which temporary shut-in can substitute, as discussed below).

An operator has the maximum ability to ensure access to a gas sales line and processing plant in the course of developing a new well. Where a nearby gathering system is already in place, the operator can work with midstream companies to determine when capacity will be available, and/or the operator can contract with the company to ensure take-away capacity is reserved for them. If a gathering system with capacity is not already in place, the operator can provide a midstream company with information well in advance of production regarding the expected timing and anticipated quantity of available natural gas, which is the information needed by gathering system operators to justify investing in new connections or capacity expansions. This is not a matter of operators hoping that downstream entities will voluntarily provide take-away capacity within a certain timeframe. Rather, these are business arrangements, and if operators are willing to pay for guaranteed take-away capacity by a given date, the market is more than capable of supplying that. The operator may pay slightly more for the take-away service, but the concept of incurring a net cost is entirely reasonable, and in fact the norm, in the context of pollution control. As Rystad notes, some larger operators prefer to develop their own gathering system capacity, giving them complete and sole control over the availability of gathering capacity.[996] All operators, however, fully control the timing of bringing their new wells online, so they can provide themselves the time necessary to exchange information and negotiate contracts with the midstream company, as well

sudden unavoidable failure, breakdown, event, or malfunction, beyond the reasonable control of the Operator, of any equipment or process that results in abnormal operations and requires correction" and which poses a danger to human safety. (Wording quoted from Colorado venting and flaring regulations, found at 2 Colo. Code Regs. 404-1 § 100.

[996] Attachment W at 46.

as ensure that the well is already connected to a gathering system with capacity, prior to starting production.[997]

The basic ability of the market to supply take-away capacity operates for existing wells no differently than for new ones. While operators cannot simply delay production start-up as at a new well, a temporary shut-in of the well is functionally equivalent in terms of aligning the timing of production with available capacity; as Rystad notes, temporary shut-ins have been observed to have little effect on future well productivity.[998] All operators, however, fully control the timing of bringing their new wells online, so they can provide themselves the time necessary to exchange information and negotiate contracts with the midstream company, as well as ensure that the well is already connected to a gathering system with capacity, prior to starting production.[999]

The basic ability of the market to supply take-away capacity operates for existing wells no differently than for new ones. While operators cannot simply delay production start-up as at a new well, a temporary shut-in of the well is functionally equivalent in terms of aligning the timing of production with available capacity; as Rystad notes, temporary shut-ins have been observed to have little effect on future well productivity.[1000] Existing wells also have the same access as new wells have to alternative transport options, options for on-site use, and options for reinjecting. Because existing wells will no longer be operating at peak flow rates,[1001] connecting them to gathering systems is highly unlikely to trigger any operational challenges for the gathering systems from very high gas pressures and flows. In addition, operators of existing wells will have several additional years of lead time until the regulatory requirements apply, compared to new wells. This provides substantial additional time for expansion of gathering system capacity and contract negotiations for firm take-away capacity, and will tend to lower costs, on average, compared to new wells.

#### 3. *EPA Should Enhance Operational Requirements for Flares to Reduce Emissions from Remaining Flaring, and Should Impose Monitoring and Reporting Requirements Under § 114*

Even if EPA adopts the full set of recommendations we provide in these comments, there will still be residual flaring of associated gas due to phase-in of requirements and all nonroutine flaring. To minimize the resulting emissions, EPA should enhance monitoring requirements and ensure flares are operating at optimum efficiency and deploying technologies that will help prevent malfunction.

Section 114 of the Clean Air Act authorizes EPA to set monitoring and other requirements for owners and operators of stationary sources subject to regulation under section 111, and grants EPA the authority to monitor compliance as it sees fit.[1002] Specifically, under section 114 (a)(1), the

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[997] *See* Attachment W at 80.
[998] Attachment W at 80.
[999] *See* Attachment W at 80.
[1000] Attachment W at 80.
[1001] *See* EIA, INITIAL PRODUCTION RATES IN TIGHT OIL FORMATIONS CONTINUE TO RISE (Feb. 11, 2016) https://www.eia.gov/todayinenergy/detail.php?id=24932 (last accessed Jan. 27, 2022).
[1002] *See* 42 U.S.C. § 7414(a)(1).

Administrator may require owners or operators to "submit compliance certifications"[1003] and "provide such other information as the Administrator may reasonably require",[1004] on a one-time, periodic, or continuous basis.[1005] Accordingly, EPA should exercise its authority under sections 111 and 114 to both enhance operational requirements and require well operators to report any flaring incidents, including both the total time of flaring and the total estimated emissions.[1006]

***Enhancing Operational Requirements.*** As a general matter, EPA has solicited comment regarding improving flare efficacy when flaring does occur. A 2020 EDF study of flares in the Permian Basin found that 10% of all flares were either unlit or only partially functioning.[1007] EPA should adopt effective monitoring and reporting requirements to effectively address this widespread issue. Further, we urge EPA to adopt regulations requiring that in any case in which flaring does occur, flare efficacy is improved to 98% control efficiency on a continuous basis.[1008]

***Establishing Monitoring Requirements.*** In the case of unplanned flaring for reason of emergency, well operators should submit their report no later than 12 hours after the event,[1009] and should be required to provide justification for the flare, demonstrating that its reason for flaring falls within EPA's narrowly defined set of emergency circumstances. To the extent that EPA chooses to permit flaring in other narrowly defined circumstances, such as pressure testing,[1010] we propose that EPA require the operator to provide notice both no later than 24 hours *before* the event (at which time the operator should provide a projected estimate of total time and emissions)and no later than 12 hours *after* the event (at which time the operator should provide an estimate of time and emissions actually produced). Planned flaring instances should be rare and subject to specific EPA restrictions. Indeed, the technology exists to conduct pressure testing activity without flares.[1011]

### J. Abandoned Wells

Abandoned wells that are improperly plugged or not plugged are a significant source of emissions[1012] and may pose a safety threat. EPA estimates there are 2.1 million unplugged and

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[1003] *See id.* at § 7414(a)(1)(F).
[1004] *See id.* at § 7414(a)(1)(G).
[1005] *See id.* at 7414(a)(1).
[1006] Under state of Colorado regulations, which ban flaring except in limited circumstances, operators must notify the state regulatory authority of planned and unplanned flaring events, and must provide an estimate of "volume and content of gas" flared, as well as an "explanation, rationale, and cause" for the flaring event. *See* Code of Colorado Regulations, Oil and Gas Conservation Commission, 2 CCR 404-1 § 903(d)(2)(A),(C) (accessible at https://www.sos.state.co.us/CCR/GenerateRulePdf.do?ruleVersionId=9245).
[1007] EDF, Flaring Aerial Survey Results (2021), https://www.permianmap.org/flaring-emissions/ (last accessed Oct. 27, 2021).
[1008] *See* 86 Fed. Reg. at 63228, noting that combustion devices can be designed to meet 98% control efficiencies.
[1009] *See* 2 Colo. Code Regs. 404-1 § 903(a)(2).
[1010] For comparison, under Colorado regulations, venting or flaring is permitted "during and as part of active and required maintenance and repair", and "during a Bradenhead test pursuant to Rule 419." 2 Colo. Code Regs. 404-1 § 903(d)(1)(B),(E) (accessible at https://www.sos.state.co.us/CCR/GenerateRulePdf.do?ruleVersionId=9245).
[1011] For an example of this approach in practice, see Sclumberger, Zero-Flaring Well Test and Cleanup (2022) https://www.slb.com/reservoir-characterization/reservoir-testing/zero-flaring-well-test-and-cleanup
[1012] EPA estimates between 64,000 to 404,000 metric tons of methane per year. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2018* (2020), https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks.

abandoned wells nationwide emitting methane into the atmosphere.[1013] EPA further estimates that these wells emitted 55,000 metric tons of methane in 2019 alone,[1014] and other studies suggest that the number may be much higher.[1015]

Many wells are orphaned or owned by entities that cannot pay to properly plug them, leaving that task to states and taxpayers—and the price tag can be hefty. According to a 2010 GAO report, between 1988 and 2009, the Bureau of Land Management (BLM) reclaimed 295 orphaned wells and spent an average of $12,788 per well, with costs ranging as high as $582,829 for a single well.[1016] We appreciate EPA's attention to this issue , and here offer comments in response to the agency's request for information on potential solutions to this important problem. We are strongly in favor of EPA minimizing emissions from abandoned wells,[1017] and we urge EPA to explore various options to achieve that end.

As discussed in Section IV.A (fugitive monitoring), the proposed exemption from regular monitoring for sites below 3 tpy is problematic for end-of-life well issues. Exempting these sites from federal regulatory standards enables strategic asset transfers that perpetuate the cycle of improper abandonment and orphaning.[1018] When smaller and declining sites are exempt from standards that apply to all other wells, it creates a perverse incentive to keep those wells in production for far longer than if the true costs were internalized. It also allows operators to forgo upkeep and maintenance required by methane regulations, creating high-emitting and dangerous site conditions. With no federal regulatory oversight and highly inconsistent state oversight,[1019] operators often keep wells open beyond when they otherwise might in order to avoid the cost of plugging; many such wells would likely not be profitable if they were obligated to internalize plugging costs. Many of these companies go bankrupt, leaving taxpayers holding the bag.[1020] Exemptions for these sites allow operators to avoid yet another cost and disincentivize proper closure.

In this section, we use the following definitions:

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[1013] Jason Bordoff, et al., *Green Stimulus for Oil and Gas Workers: Considering a Major Federal Effort to Plug Orphaned and Abandoned Wells*, Colombia Center on Global Energy Policy (2020), https://www.energypolicy.columbia.edu/research/report/green-stimulus-oil-and-gas-workers-considering-major-federal-effort-plug-orphaned-and-abandoned

[1014] *See* EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks (2021), https://www.epa.gov/sites/default/files/2021-04/documents/us-ghg-inventory-2021-main-text.pdf at 3-111.

[1015] *See, e.g*, EDF, Documenting Orphan Wells Across the United States (2021), https://www.edf.org/orphanwellmap (last accessed Nov. 30, 2021).

[1016] *Id.* at 16.

[1017] *See* 86 Fed. Reg. at 63240 ("The EPA is soliciting comment for potential NSPS and EG to address issues with emissions from abandoned, or nonproducing oil and natural gas wells that are not plugged or are plugged ineffectively.")

[1018] Zachary R. Mider and Rachel Adams-Heard, An Empire of Dying Wells, Bloomberg (Oct. 2021), https://www.bloomberg.com/features/diversified-energy-natural-gas-wells-methane-leaks-2021/

[1019] Ho et al., *Managing Environmental Liability: An Evaluation of Bonding Requirements for Oil and Gas Wells in the United States*, 52 Env. Sci. Tech. 3908 (2018), https://pubs.acs.org/doi/10.1021/acs.est.7b06609

[1020] Alex Wolf, *Bankruptcies Fueling Environmental Crisis at Abandoned Oil Wells*, Bloomberg Law (Sept. 2, 2021), https://news.bloomberglaw.com/bankruptcy-law/bankruptcies-fueling-environmental-crisis-at-abandoned-oil-wells ("More than 260 domestic oil producers filed Chapter 11 over a six-year period . . . . Many distressed fossil fuel companies are passing environmental obligations on to government bodies . . . .").

An *abandoned well* is a well that is not producing and that the operator does not presently intend to return to production.

An *orphan well* is an abandoned well where the operator or owner is insolvent or unknown.

A *plugged well* is a well that is no longer in production and has been plugged.

A *shut-in well* is a well where the valves have been closed so it is not producing.

A *wellhead only* is a well where all equipment has been removed other than the Christmas tree piping.

Under section 111, EPA may define "affected facilities" in various ways and set the parameters that a source must meet to qualify as an affected facility.[1021] For example, EPA has allowed operators to remove all major production and processing equipment from a well site to become a "wellhead only" site, which is not an affected facility for purposes of fugitive monitoring.[1022] EPA should clarify in the well site affected facility definitions that any well which has not been properly plugged with cement according to the applicable state or federal standards is still an affected facility subject to LDAR and any other applicable standards.[1023] This would incentivize proper closure because it would provide an off-ramp from affected facility status, allowing operators to avoid incurring compliance costs that would otherwise be mandatory. Operators of shut-in or abandoned wells would thus be forced to choose between compliance costs and plugging, rather than remaining in a potential gray area and doing neither.

The wellhead only exemption from LDAR is another potential barrier to this approach because many idle or abandoned wells will satisfy this definition and have little incentive to plug. EPA could resolve this problem easily by eliminating the wellhead only exemption. If EPA retains that exemption, it will have to otherwise address this issue, potentially by setting time limits on the applicability of the exemption or requiring reporting on the status of these wells.

EPA can also require operators to submit plans detailing how they will comply with various standards, like the requirement to submit a fugitive monitoring plan. EPA should use this approach when dealing with end-of-life wells by requiring operators of well site affected facilities to submit closure plans, detailing how the site will be monitored or plugged, and if the latter, identifying the financing that will be used for plugging, along with other relevant information.[1024] When the operator chooses to close a well, thereby removing it from affected facility status, it would be required to follow the steps in the plan. Failure to do so would cause the well site to remain an

[1021] *See* 42 U.S. Code § 7411(a).
[1022] 40 CFR § 60.5430a.
[1023] EPA might consider a variance from this requirement for orphaned wells that are already on a list to be plugged.
[1024] Section 114, 42 U.S.C. § 7414, gives EPA broad information gathering authority that EPA could use to gain information on operator's financial health. EPA could use that information to identify wells at high risk of abandonment and take proactive steps to prevent those wells from becoming orphaned or transferred. EPA could also provide states with this information, which states could use to inform existing efforts to prevent orphan wells.

affected facility, and the operator would have to continue complying with fugitive monitoring and other applicable standards or face noncompliance penalties.

Alternatively, EPA could create a separate abandoned well affected facility definition, for which the standard would be monitoring until proper closure. This would have the same effect as the approach described above, where operators could choose between regular monitoring and well closure with proper plugging. Similar to the "closed landfill subcategory," EPA could require operators to submit closure plans and require regular monitoring for leaks until the closure plan is completed. This option may be more difficult to administer, however, because it would require EPA to define abandoned well affected facilities.

Under section 111(d), EPA must allow states when applying a standard of performance to an existing source to consider the remaining useful life (RUL) of the source and other factors.[1025] EPA has authority to define how states may consider remaining useful life and may also limit what other factors states consider.[1026] EPA must require a source that is granted a compliance variance on RUL grounds to commit to a federally enforceable shut-down at the end of its useful life (as we discuss in more detail below), and must specify the conditions of closure. Any variance justified by a short RUL necessarily entails on a certain closure date, and EPA must not allow sources that are permitted to forgo required applicable to all other sources on RUL grounds to continue operating beyond that date.

Under section 111(d), EPA can also specify and limit the "other factors" states are allowed to consider when applying a standard of performance to an existing source.[1027] For example, EPA might require states to consider the financial stability of the operator and specify that EPA would not approve any variance for sources owned by operators with poor finances unless they provide financial assurances to EPA or the relevant state agency. This could even be done on an operator-wide rather than source-by-source basis. Colorado is updating its financial assurance regulations and may consider the percentage of an operator's portfolio that is active versus inactive as a proxy for financial stability.[1028] EPA could do something similar, for example, by requiring a financial demonstration as a condition of approving a variance, or simply not approving a variance for sources owned by an operator with a high percentage of inactive or risky wells.

### K. Pigging Operations and Related Blowdown Activities

Pipeline pigging and blowdown activities are a notable source of methane, and technology and work practices are readily available to mitigate these emissions. EPA correctly identified this issue in the proposal as an area of concern, and effective approaches exist to reduce emissions from these processes. The agency should therefore include proposed performance standards and

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[1025] 42 U.S.C. § 7411(d)(1).
[1026] *See id.*
[1027] *Id.*
[1028] *See* Colorado Oil and Gas Conservation Commission, Draft Financial Assurance Rules (Dec. 7, 2021), https://cogcc.state.co.us/documents/sb19181/Rulemaking/Financial%20Assurance/COGCC%20Draft%20Financial%20Assurance%20Rules%2012-7-21%20-%20Redline%20against%2010-8-21%20Draft.pdf ; Mark Jaffe, Colorado doesn't want to foot the bill for abandoned oil and gas wells. Here's how it will avoid picking up the tab., Colorado Sun (June 17, 2021), https://coloradosun.com/2021/06/17/colorado-orphan-oil-well-bonding-cogcc/.

emission guidelines for pigging and blowdown activities on gathering pipelines in its supplemental proposal... Because pigging and blowdown activities are similar on transmission pipelines, EPA should also consider proposing performance standards and emissions guidelines for pigging and blowdown activities on transmission pipelines. EPA should continue to coordinate with the Pipeline and Hazardous Materials Safety Administration (PHMSA) at U.S. DOT, to ensure comprehensive oversight of pipeline methane emissions across agencies.

1. *Methane Releases from Pigging and Blowdowns on Gathering Lines are Significant*

Gathering pipelines have historically been subject to minimal federal oversight and are drawing increasing scrutiny as an environmental and safety concern. There are currently over 430,000 miles of onshore gas gathering lines in the United States,[1029] yet EPA has never regulated pollution emissions from this equipment, although it has regulated associated gathering and boosting infrastructure in its oversight of methane emissions from gas production and processing. In 2020, PHMSA regulated only 11,569 miles of onshore gas gathering lines, which are subject to reporting and leak survey and repair requirements.[1030]

The surge in domestic U.S. gas production since 2006 resulted in a significant expansion in the mileage of the gathering pipeline network and the volume of gas transported by gathering lines[1031] Before 2006, gathering lines were generally smaller-diameter and lower pressure-pipelines that were "thought to pose relatively low risk to the public and the environment."[1032] But as industry expansion has placed increasing demand on this infrastructure, "[m]odern gas gathering lines often bear a closer resemblance to large interstate transmission lines than the diffuse network of small, low-pressure lines that previously characterized gathering lines."[1033] Larger pipelines pose a greater risk of safety and environmental incidents and release higher volumes of methane during blowdown and pigging events.[1034]

Emissions from pipelines can be categorized as either fugitive emissions that result from leaks, or operational emissions that result from pigging, blowdowns, and other activities associated with operation of the pipeline. Recent surveys and research have found that gathering lines are a significant source of methane emissions, including super-emitting events. Airborne surveys in the Permian Basin across Texas and New Mexico found that about 30 facilities persistently emitted

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[1029] Highwood Emissions Management, Technical Report: Leak detection methods for natural gas gathering, transmission, and distribution pipelines at 13 (Jan. 12, 2022), https://highwoodemissions.com/pipeline-report/.
[1030] PHMSA, Annual Report Mileage for Natural Gas Transmission & Gathering Systems, Year 2020 (last updated Jan. 4, 2022), https://www.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-natural-gas-transmission-gathering-systems.
[1031] *See* U.S. Dep't of Trans., PHMSA, Final Rule: *Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments*, 86 Fed. Reg. 63,266, 63,267 (Nov. 15, 2021) ("Gathering Line Rule").
[1032] *Id.* at 63,266-67.
[1033] *Id.* at 63,271.
[1034] *See* M.J. Bradley & Associates, Pipeline Blowdown Emissions and Mitigation Options at 11 (June 2016), http://blogs.edf.org/energyexchange/files/2016/07/PHMSA-Blowdown-Analysis-FINAL.pdf.

large volumes of methane over multiple years (2019-2021), and repairing those leaks could immediately reduce 100,000 metric tons of methane per year.[1035] Nearly 20% of the persistent super-emitting leaks were from gathering pipelines.[1036] While persistent emission points on gathering lines are likely attributable to pipeline leaks, intermittent methane super-emitter events have also been identified on gathering pipelines, and may be the result of pigging and blowdown activities.[1037]

The PIPES Act of 2020 directed PHMSA to finalize new standards to extend its oversight of gathering lines.[1038] In November 2021, PHMSA issued a final rule extending basic annual reporting requirements to all onshore gas gathering lines and extending leak survey and repair requirements to an additional 20,336 miles of gathering lines.[1039] The rule represents an important step forward to increase transparency and heighten oversight of gathering pipelines. However, it does not establish requirements to limit methane emissions from pigging and blowdown activities. EPA should remedy this oversight and propose emission limitations for pigging and blowdowns on gathering lines in its forthcoming supplemental rulemaking.

### 2. *Prevalence of Pigging and Blowdowns*

Blowdowns are conducted intermittently on natural gas pipelines for multiple reasons, including to conduct integrity inspections, clean a pipeline, or conduct repairs. Blowdowns conducted without mitigation practices can be significant emissions events, as all of the gas is evacuated from a segment of pipeline. A recent transmission pipeline blowdown by Kinder Morgan in Texas released approximately 25,000 dekatherms of methane as part of a road construction project, and the release was detected by a European Space Agency satellite.[1040] Upstream of gas processing plants, blowdowns and pigging activities release not only methane, but significant amounts of other pollutants, including VOCs and hazardous air pollutants.[1041] Pipeline operators conduct blowdowns on all types of pipelines: gathering, transmission, and distribution pipelines. Although pigging activities are most common to clean gathering pipelines transporting unprocessed gas, they are also used on transmission and distribution lines—for example, smart pigs may be deployed in any type of pipeline for integrity management, to identify stress, corrosion, and leaks.[1042]

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[1035] EDF & Carbon Mapper, Press Release: Dozens of "super-emitting" oil and gas facilities leaked methane pollution in Permian Basin for years on end (Jan. 24, 2022), https://www.edf.org/media/dozens-super-emitting-oil-and-gas-facilities-leaked-methane-pollution-permian-basin-years-end.

[1036] *Id.*; *see also* Cusworth et al., Intermittency of Large Methane Emitters in the Permian Basin, *Environ. Sci. Technol. Lett.* 2021, 8, 7, 567–573 (June 2, 2021), https://doi.org/10.1021/acs.estlett.1c00173.

[1037] *See* Cusworth et al., Intermittency of Large Methane Emitters in the Permian Basin, *Environ. Sci. Technol. Lett.* 2021, 8, 7, 567–573 (June 2, 2021), https://doi.org/10.1021/acs.estlett.1c00173.

[1038] FY2021 Omnibus and COVID Relief Response Act, HR133, Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (PIPES Act of 2020) at § 112(a) (Dec. 27, 2020).

[1039] PHMSA, *Final Rule: Pipeline Safety: Safety of Gas Gathering Pipelines*, 86 Fed. Reg. 63,266 (Nov. 15, 2021).

[1040] Naureen S Malik & Aaron Clark, How a Rural Texas Road Project Triggered a Cloud of Methane, Bloomberg (Dec. 1, 2021), https://www.bloomberg.com/news/articles/2021-12-01/this-rural-texas-road-project-triggered-a-cloud-of-methane.

[1041] *Supra* Section II.I.

[1042] *See* Proposal at p63,242; *see also* Page Leggett, *How smart PIGs keep pipelines safe*, Duke Energy Illumination (Jan. 6, 2017) (explaining that Piedmont Natural Gas uses cleaning pigs and smart pigs to inspect "hundreds of miles of transmission pipelines each year"), https://illumination.duke-energy.com/articles/how-smart-pigs-keep-pipelines-safe.

EPA states in the proposal that through the 2019 GHGRP, operators reported "472,995 total individual blowdown events from 1,212 facilities for a combined 307,630 metric tons of methane emitted, including 79,746 events at pig launchers or receivers for a combined total of 19,066 metric tons of methane."[1043] EPA acknowledges that the GHGRP data only includes emissions from blowdown equipment with a "unique physical volume greater than 50 cubic feet and occurring at a facility with total emissions greater than 25,000 metric tons CO2 Eq."[1044] Because there may be blowdown events on gathering lines below the EPA reporting threshold, it is likely that EPA's data underreports the true extent of emissions from these events. Furthermore, small gathering line operators "are less likely to have data on the characteristics of their gathering lines readily available," and that "data on the characteristics of older gathering lines are less likely to exist than for newer pipelines."[1045] For this reason also, pipeline operators reporting to the GHGRP may provide data that underestimates the actual emissions resulting from blowdowns.

The blowdown emissions EPA describes in the proposal appear to be limited to gathering lines, but similar activities occur on transmission and distribution pipelines and cause significant emissions. EPA quantifies methane emissions from pipeline blowdowns under the following categories in the Greenhouse Gas Inventory:

| Methane Emissions from Pipeline Blowdowns, 2019[1046] | |
|---|---|
| *Segment* | *CH4 Emissions (kt)* |
| Production – G&B Pipeline Blowdowns | 31.5 |
| Transmission – Pipeline Venting | 199.4 |
| Distribution – Pipeline Blowdown | 4.4 |
| TOTAL | 235.3 |

EPA should establish limits on pipeline operational emissions for both gathering and transmission lines, and across different blowdown activities. If EPA pursues a supplemental rulemaking focused solely on operational emissions on gathering lines, it should consider all blowdowns on gathering lines rather than limiting its focus to pigging. Below, we discuss the kinds of mitigation practices that can limit emissions from blowdown and pigging events.

### 3. *Technology and Work Practices are Readily Available to Mitigate Pipeline Emissions*

The proposal documents multiple proven technologies and practices that are available to reduce blowdown and pigging emissions, focusing on jumper lines, vapor recovery units or other fuel gas

[1043] Proposal at p63,242.
[1044] Proposal at p63,242-43.
[1045] U.S. Gov't Accountability Office, Operators of Natural Gas and Hazardous Liquid Gathering Lines Face Data Collection Challenges at 9, 10, Report No. GAO-22-104817 (Jan. 2022), https://www.gao.gov/assets/gao-22-104817.pdf.
[1046] U.S. EPA, Natural Gas and Petroleum Systems in the GHG Inventory: Additional Information on the 1990-2019 GHG Inventor, Annex 3.6: Methodology for Estimating CH4, CO2, and N2O Emissions from Petroleum Systems (published Apr. 2021), https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2019-ghg.

systems, small compressors (barrel pump-down systems), and flares.[1047] As discussed in a report by M.J. Bradley & Associates, these kinds of mitigation technologies and practices can reduce methane emissions from gas pipeline blowdown by up to 90%.[1048] The M.J. Bradley report details five mitigation options, four of which are also identified in EPA's proposal: pressure reduction with in-line compressors, pressure reduction with mobile compressors, transfer of gas to a low-pressure system, isolating a small pipeline section with stopples, and flaring. The report provides detailed cost and man-hour estimates for each mitigation option,[1049] summarized in the table below.

**Table 6 Costs and Benefits of Blowdown Mitigation Options**

| MITIGATION OPTION | Cost ($/event) | | Methane Reduction (MT/event) | | Average Cost ($/MT) | |
|---|---|---|---|---|---|---|
| | Interstate | Intrastate | Interstate | Intrastate | Interstate | Intrastate |
| Flaring | $2,665 | $2,014 | 123.7 | 65.4 | $22 | $31 |
| In-line Compression | $1,013 | $710 | 61.2 | 32.3 | $17 | $22 |
| Mobile Compressor | $13,747 | $13,282 | 108.3 | 57.3 | $127 | $232 |
| Transfer to Low Pressure | $1,309 | $1,164 | 68.5 | 36.2 | $19 | $32 |
| Stopples | $63,059 | $63,059 | 102.8 | 54.3 | $613 | $1,161 |

*Source: MJB&A Analysis.*

As these data show, all of these measures are highly cost-effective, and in most cases, one to two orders of magnitude lower than values that EPA has in the past defined as cost-effective for methane controls. However, consistent with our recommendations in these comments for other sources, flaring is a decidedly inferior control strategy from both environmental and waste perspectives, and should only be permitted as a means of avoiding venting during blowdown and pigging events when all other options are either truly unavailable or would present safety concerns. Furthermore, documentation of successful blowdown emissions mitigation efforts indicates the value of specific and detailed work practices. Operators must normalize and incorporate work practices into their regular operations so that consideration of methane abatement is part of the job. Below, we describe some of the work practices (some of which overlap with the measures identified in the M.J. Bradley report) that can successfully curb emissions from pipeline blowdown and pigging events.

***California Gas Utility Methane Abatement Practices***. California law SB1371, enacted 2014, requires natural gas utilities to minimize methane emissions from the transmission and distribution systems. The California Public Utilities Commission approved a gas leak abatement program as

[1047] *See* Proposal at 63,244; Technical Support Document at 14-14 – 14-15.
[1048] M.J. Bradley & Associates, Pipeline Blowdown Emissions and Mitigation Options at 14 (June 2016), http://blogs.edf.org/energyexchange/files/2016/07/PHMSA-Blowdown-Analysis-FINAL.pdf.
[1049] *Id.* at 14-20. The report also quantifies the benefits of each mitigation option based on the economic and social value of saved gas, but these values may no longer reflect the most recent and accurate Social Cost of Carbon and Social Cost of Methane values.

part of SB1371 implementation, adopting 26 mandatory Best Practices ("BPs") for minimizing methane emissions that include multiple provisions to reduce blowdown emissions[1050] These BPs, which could also help to reduce emissions from pigging activities, include the following:[1051]

- BP23, Minimize Emissions from Operations, Maintenance and Other Activities – "Utilities shall minimize emissions from operations, maintenance and other activities, such as new construction or replacement, in the gas distribution and transmission systems and storage facilities. Utilities shall replace high-bleed pneumatic devices with technology that does not vent gas (i.e. no-bleed) or vents significantly less natural gas (i.e. low-bleed) devices. Utilities shall also reduce emissions from blowdowns, as much as operationally feasible."

- BP5, Methane Evacuation Procedures – Utilities shall establish "[w]ritten company procedures implementing the BPs approved for use to evacuate methane for non-emergency venting of high pressure distribution (above 60 psig), transmission or underground storage infrastructure and how to use them consistent with safe operations and considering alternative potential sources of supply to reliably serve customers."

- BP6, Methane Evacuation Work Orders Policy – Utilities shall establish a "[w]ritten company policy that requires that for any high pressure distribution (above 60 psig), transmission or underground storage infrastructure projects requiring evacuating methane, Work Planners shall clearly delineate, in procedural documents, such as work orders used in the field, the steps required to safely and efficiently reduce the pressure in the lines, prior to lines being vented, considering alternative potential sources of supply to reliably serve customers."

- BP7, Bundling Work Policy – Utilities shall establish a "[w]ritten company policy requiring bundling of work, whenever practicable, to prevent multiple venting of the same piping consistent with safe operations and considering alternative potential sources of supply to reliably serve customers. Company policy shall define situations where work bundling is not practicable."

California gas utility Pacific Gas & Electric Company (PG&E) has documented in detail the implementation of practices to minimize blowdown emissions in its Leak Abatement Compliance Plan, as required by SB1371.[1052] The company reported that "[f]or non-emergency gas transmission pipeline blowdowns, PG&E abated approximately 80 percent of the total gas volume released from its transmission pipeline projects through drafting and cross compression."[1053] The breakdown of these emission reductions is presented in the table below.

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[1050] California Public Utilities Commission, Decision Approving Natural Gas Leak Abatement Program Consistent with Senate Bill 1371, Decision 17-06-015, Appendix B: Best Practices for Natural Gas Leak Abatement Program (June 15, 2017).
[1051] *Id.* at B5-B6, B14-B15.
[1052] PG&E, 2020 Leak Abatement Compliance Plan (submitted Mar. 16, 2020; amended Oct. 19, 2020).
[1053] *Id.* at 1-1.

Table: PG&E 2018 Transmission Pipeline and Regulator Station Abatement Activities

| Pipeline Activity Type | Total Gas Volume (Mscf) |
|---|---|
| Drafting | 119,837 |
| Cross Compression | 504,320 |
| Blowdown | 159,215 |
| *Total Gas Baseline* | *783,372* |
| *Percent Gas Diverted to Drafting or Cross Compression* | *80%* |

To reduce methane emissions during non-emergency blowdowns, PG&E developed a new standard and procedure, TD-5601S and TD-5601P-01. The new standard provides numerous directives, including to "[s]chedule all planned gas transmission system construction projects with sufficient lead time to incorporate emission reduction strategies, including project bundling, drafting, cross compressing and flaring."[1054]

The company's Plan also identifies numerous next steps that it will undertake to improve on its existing best practices for blowdowns, suggesting that further methane emissions mitigation can be achieved. For example, the company describes a goal to purchase additional trailers with mobile compressors so that multiple compression jobs can proceed simultaneously; to investigate purchasing a "gas-driven mobile fill compressor and tube trailers . . . to use mobile compression" to reduce emissions from smaller blowdowns or pipelines that do not have a nearby pipeline to cross-compress into; and to "[e]xplore the applicability and feasibility of using multi-stage/boost compressors to further reduce the amount of gas released during backbone pipeline blowdowns."[1055]

Additionally, the company is evaluating new technology to replace flaring by catalytically oxidizing methane, through a pilot project with Stanford University and NYSEARCH.[1056] The company is exploring other technologies to reduce blowdown emissions:

> PG&E plans to explore the use of ZEVAC technology in gas operation activities. ZEVAC uses compressed air to eliminate emissions. The compressed air is used to suction the pipeline segment and compresses the gas into an adjacent pipeline or tank. The intake could then be discharged back into the system. ZEVAC technology will be assessed for use in reducing emissions from non-emergency blowdowns and has the potential to further reduce emissions from non-emergency blowdowns.[1057]

***Methane Guiding Principles***. The Methane Guiding Principles ("MGP") is a voluntary, international partnership that has issued detailed best practices to reduce methane emissions along the natural gas supply chain, developed by a coalition of industry and civil society

[1054] *Id.* at 1-13, 1-55, 1-61.
[1055] *Id.* at 1-15 – 1-16.
[1056] *Id.* at 1-47 – 1-48.
[1057] *Id.* at 1-48.

organizations.[1058] The MGP includes best practices to reduce methane emissions from pipeline pigging and blowdown activities.

Regarding pigging, the MGP recommends the use of pig ramps and jumper lines to reduce emissions during the insertion and removal of a pig from a pipeline. The operating requirements include "extra time . . . from the pig being received to it being removed from the receiver to allow the liquids to drain back to the pipeline," as well as a low-pressure system "available on-site to accept the gas from the pig trap."[1059] The guide reports industry estimates that "using pig ramps and jumper lines can reduce emissions from pigging by up to 85% at a cost of approximately US $8,175 per facility."[1060] Additionally, the MGP recommends use of a vapor recovery unit to capture the gas vented when a pig is launched/received, and the gas released from storage tanks that receive the liquid and debris removed by the pig.[1061] As a last resort, captured gas can be flared rather than vented, although we emphasize again that flaring should only be used when other alternatives to venting are not feasible or would jeopardize safety.[1062]

Regarding blowdowns, the MGP recommends an initial practice of avoiding blowdowns whenever possible. Inline-inspection tools and smart pigs (with the other mitigation measures discussed to reduce pigging emissions) that can be deployed without having to blowdown a pipeline segment are preferable, and necessary blowdowns should be planned in advance and bundled to decrease overall emissions.[1063] When blowdowns must occur, the MGP details additional mitigation strategies to reduce blowdown emissions, which are aligned with the EPA proposal:

- Lower the pressure in the pipeline by allowing consumer drawdown;
- Re-route the gas to an existing network with lower pressure or use it as fuel;
- Recompression;
- Mobile compressor stations;
- Install plugging equipment to shorten the segment of pipeline involved; use isolation valves to minimize impact;
- Make new connections and repair with a hot tap;
- Use in-line inspection (ILI), or 'smart pig' technologies instead of hydrotests
- Reroute the natural gas to a duct burner, thermal oxidizer, or flare if possible, planned, and allowed (although flaring is not always possible during an emergency, and should only be used when other options are infeasible or unsafe).[1064]

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[1058] Methane Guiding Principles, About, https://methaneguidingprinciples.org/about/ (last visited Jan. 25, 2022).
[1059] Methane Guiding Principles, Reducing Methane Emissions: Best Practice Guide, Engineering Design and Construction at 11 (Nov. 2019), https://methaneguidingprinciples.org/wp-content/uploads/2019/11/Reducing-Methane-Emissions-Engineering-Design-Guide.pdf.
[1060] *Id.* at 12.
[1061] Methane Guiding Principles, Reducing Methane Emissions: Best Practice Guide, Operational Repairs at 9 (Nov. 2019), https://methaneguidingprinciples.org/wp-content/uploads/2019/11/Reducing-Methane-Emissions-Operational-Repairs-Guide.pdf.
[1062] *Id.*
[1063] *Id.* at 12.
[1064] Methane Guiding Principles, Reducing Methane Emissions: Best Practice Guide, Transmission, Storage, LNG Terminals and Distribution at 9 (Sept. 2020), https://methaneguidingprinciples.org/wp-content/uploads/2020/09/Reducing-Methane-Emissions-transmission-storage-LNG-terminals-and-distribution-

***Colorado Pigging and Blowdown Standards.*** The Colorado Air Quality Control Commission recently adopted standards to limit oil and gas methane and air pollution, including establishing requirements to reduce pipeline pigging and blowdown emissions.[1065] The Commission requires that pipeline "owners or operators capture and recover gas from pigging and blowdown activities, and if not possible, to request Division approval to install and operate air pollution control equipment, such as vapor recovery, flare/combustors, or a Division-approved alternative to achieve a 95% reduction in hydrocarbon emissions."[1066]

The standard requires that pipeline owners or operators use "best practices to minimize emissions from pigging operations and blowdowns during normal operations."[1067] The identified best practices include (a) keeping pipeline access openings on the pig receiver closed at all times except when a pig is being placed into or removed from the receiver, or during active pipeline maintenance activities; (b) using liquids management system to reduce the accumulation of liquids in the pigging unit; (c) rerouting gas to a low-pressure system using existing piping connections, temporarily resetting or bypassing pressure regulators to reduce system pressure prior to maintenance, or installing temporary connections between high- and low-pressure systems. The standards also require that operators create or update an operating and maintenance plan to provide for the use of these additional best practices:

1. Using short pig barrels, where it reduces the gas volume for potential release.
2. Planning for venting-reduction steps, such as pipeline pumpdowns techniques (e.g., in-line compressors, portable compressors, ejector), when large vessels and pipelines need to be isolated and depressurized.
3. Minimizing the volume that must be released. For example, adding stops to isolate a smaller section of a pipeline to reduce the length of pipe that must be vented.
4. Using inert gases and pigs to perform pipeline purges.
5. Hot tapping to make new connections to pipelines.
6. Coordinating operational repairs and routine maintenance to minimize the number of emissions events and volume.[1068]

There are numerous cost-effective technologies and work practices that can significantly reduce methane emissions from pipeline blowdowns. The examples provided above do not represent all available options or all operators using these practices. EPA should consider these and all other potential options as it considers a supplemental proposal to address methane emissions from blowdown and pigging activities on pipelines.

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Guide.pdf; *see also* Methane Guiding Principles, Reducing Methane Emissions: Best Practice Guide, Operational Repairs at 12 (Nov. 2019) (referring to the use of hot taps and flaring).

[1065] Colorado Air Quality Control Commission, Regulation No. 7, 5 CCR 1001-9 Section II.H at p164-171, available at https://drive.google.com/file/d/1JXzWUuPedxqHVCqiU6BdK3GJn_Z0x50X/view.

[1066] *Id.* at p396, Part X., Statement of Basis, Specific Statutory Authority, and Purpose for December 17, 2021 Revisions.

[1067] *Id. at* 5 CCR 1001-9 Section II.H.4 at p169.

[1068] *Id.* at 5 CCR 1001-9 Section II.H.4.d. at p170.

### 4. *Pipelines Could be Defined as an Affected Facility*

EPA solicits comment on how to define an affected facility that includes blowdown activities. Pipelines themselves could be defined as an affected facility, defined by pipeline segments based on ownership and major geographic boundaries. There are benefits to defining the pipeline as the affected facility. First, bundling multiple activities into a single blowdown event is a helpful practice to reduce the total number of required blowdowns on a pipeline and thus to reduce the overall methane emissions.[1069] To facilitate planning in advance and ensuring maximum bundling to minimize emissions, it would be helpful to consider all different types of blowdowns (including pigging) and view the pipeline as a whole—or even a pipeline segment—as the affected facility.

Furthermore, it is beneficial to treat the pipeline itself as an affected facility because a blowdown is not necessarily limited to a discrete point on the pipeline. The amount of methane released during a blowdown is related to the length of the section of pipeline that must be blown down, which depends on where the pipeline has valves that can be closed. Thus, blowing down a longer length of pipeline will result in greater methane emissions:

> In order to blowdown a section of pipe, that section must be isolated from upstream and downstream pipe sections by closing valves. Valve spacing varies across the system but is generally ten to twenty miles between valves. This means that, without installing a new temporary valve[,] the minimum distance that can be blown down in order to allow for establishment of MAOP using pressure testing is 10 – 20 miles (i.e. the valve spacing on that segment of pipeline). As such, if only a two-mile section of pipe between valves needed to be pressure tested (for example because it was pre-1970 pipe in an HCA) but the rest of the section between the valves did not need to be tested (because it was not in an HCA), then the total miles that would need to be blown down to accommodate the pressure testing could be five to ten times longer than the actual pressure test mileage.[1070]

For ease of oversight and establishing the Best System of Emissions Reduction, EPA should consider defining pipelines as the affected facility, with the endpoints of each pipeline facility established in segments where appropriate. Pipeline segments could be defined by pipeline ownership and major geographic boundaries.

## V. Considerations on EPA's Proposed OOOOc Emission Guidelines for Existing Sources

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[1069] *See* Methane Guiding Principles, Reducing Methane Emissions: Best Practice Guide, Operational Repairs at 5 (Nov. 2019), https://methaneguidingprinciples.org/wp-content/uploads/2019/11/Reducing-Methane-Emissions-Operational-Repairs-Guide.pdf ("Look for opportunities to co-ordinate operational repairs and routine maintenance and repairs to minimize the number of blowdowns."); California Public Utilities Commission, Decision Approving Natural Gas Leak Abatement Program Consistent with Senate Bill 1371, Decision 17-06-015, Appendix B: Best Practices for Natural Gas Leak Abatement Program (June 15, 2017).

[1070] M.J. Bradley & Associates, Pipeline Blowdown Emissions and Mitigation Options at 14 (June 2016), http://blogs.edf.org/energyexchange/files/2016/07/PHMSA-Blowdown-Analysis-FINAL.pdf.

### A. EPA's "Best System" for Existing Sources Appropriately Mirrors its "Best System" for New Sources

By and large, EPA's proposed OOOOc methane emission guidelines for existing oil and gas sources includes the same "best system" determinations as its updated OOOOb new source requirements. Joint Environmental Commenters support this decision, since the same techniques for reducing new source emissions also apply to existing sources and, in most instances, do not entail significant cost differences between new and existing sources. In the preceding sections, we described aspects of EPA's standards we strongly support and additional ways in which we believe EPA's proposed standards could be improved and strengthened; those comments should be understood to apply equally to new and existing source requirements. But we are in fundamental agreement with EPA that, with only limited exceptions, the agency's existing source guidelines for this sector should mirror the requirements for new sources.

### B. Joint Environmental Commenters Support EPA's Proposed Criteria and Timeline for State Plan Approval Under OOOOc

Joint Environmental Commenters believe that EPA has proposed appropriate criteria for determining whether to approve state plans submitted under OOOOc. The proposal appropriately adheres to the section 111(d) implementing regulations' criteria for completeness, technical and administrative matters, and emission inventories.[1071] These requirements are critical for ensuring that state plans will in practice achieve the emission reductions required under the guidelines, and no reasons exist to deviate from them here. EPA has also appropriately proposed to grant streamlined approval for state plans that adhere to OOOOc's presumptive standards (analogous to a model rule). Plans that do not deviate in any material way from EPA's guidelines are the likeliest to achieve the anticipated level of emission reductions, and a streamlined approval process will ensure that those reductions happen at the earliest possible time. Indeed, while Joint Environmental Commenters support rigorous review of state plans, those that directly adhere to OOOOc's presumptive standards should not be subject to an unnecessary degree of administrative review when critical emission reductions are needed as soon as possible.

Joint Environmental Commenters strongly support EPA's community participation requirements described in the proposal.[1072] Oil and gas development poses major health risks to frontline communities. Oil and gas extraction frequently occurs in close proximity to homes, workplaces, schools, daycare centers, and recreational areas, and residents of those communities have no way of avoiding exposure to the pollution that results from those activities. As explained in the proposal, communities of color and low-income communities often bear a disproportionate burden and frequently suffer from the cumulative impacts of pollution and other environmental harms resulting from multiple different industries.[1073] Thus, "a robust and meaningful public participation process during State plan development is critical to ensuring that these impacts are fully

[1071] *See* 86 Fed. Reg. at 63,255 (citing requirements at 60.23a, 60.24a, 60.25a, and 60.26a, and 40 CFR 60.27a(g)(2)–(3)).
[1072] 86 Fed. Reg. at 63,253-55.
[1073] *Id.*

considered."[1074] EPA rightly points out that "robust and meaningful public involvement in the development of a State plan should go beyond the minimum requirement to hold a public hearing," but must instead include "ensuring that States share information with and solicit input from stakeholders at critical junctures during plan development, which helps ensure that a plan is adequately addressing the potential impacts to public health and welfare that are the core concern of CAA section 111."[1075]

We also encourage EPA to require that state plans engage the public in a way that is receptive to the needs and characteristics of the affected communities. For example, if a state's oil and gas industry has a significant impact on a community that includes many members who primarily speak a language other than English, the state must account for that fact as it engages that community in the plan development process. Similarly, if an affected community includes many individuals who lack access to broadband internet, the state must make a serious effort to conduct outreach through means other than just the internet. These are but two examples of the ways that states should be expected to tailor their public outreach efforts in a way that accounts for the actual communities that are affected by oil and gas development. Some states already have community outreach and engagement procedures in place. EPA should survey these existing procedures in leading states and develop a model for others to follow.

Additionally, as EPA notes in the proposal, "emissions from designated sources could cross State borders, and therefore may affect underserved and overburdened communities in neighboring States."[1076] In these situations, a state should be required to engage *all* communities that have a stake in its plan development, including those that may live across the border in another state. If a state's economic activity has a detrimental impact on residents in another state, it is only appropriate that the state address that fact as it develops plans to reduce emissions. Indeed, the Clean Air Act explicitly recognizes this in other contexts. For instance, in developing state implementation plans under the national ambient air quality standards program—a program that section 111(d) expressly cross-references[1077]—states must include provisions that "*prohibit* . . . any source or other emissions activity with the State which will . . . . contribute significantly to nonattainment in, or interfere with maintenance by, any other State."[1078] Requiring states merely to conduct appropriately robust outreach to affected communities in other states is a far more modest requirement than this, and EPA should include it in the final OOOOc rule.

Joint Environmental Commenters also strongly support EPA's proposed requirement that state plans include a compliance timeline within no more than two years of plan submission and urge the agency to consider whether a more abbreviated compliance timeline is warranted. In the source-specific sections above, we discuss the limited situations where a phased-in approach may be appropriate. As proposed, EPA does not project emission reductions from the emission guidelines until 2026. To align with the scientific imperatives and the United States' climate commitments, it is critical these reductions occur as swiftly as feasible. Owners and operators of

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[1074] *Id.* at 63,253.
[1075] *Id.*
[1076] 86 Fed. Reg. at 63,254.
[1077] *See* 42 U.S.C. § 7411(d)(1)
[1078] *Id.* § 7410(a)(2)(D)(I) (emphasis added).

existing sources are now aware that they will be required to comply with EPA standards in the coming years and will have more than three years to begin preparing for compliance. With so much lead time, and with many of the standards (like fugitive monitoring) requiring very little time to achieve compliance in any event, a phase-in approach beyond the maximum 2-year compliance timeline EPA has proposed would be inappropriate, whereas a shorter timeframe may well be justified.

### C. Under Section 111(d), EPA's Guidelines Must Establish Mandatory Requirements for State Plans, and the Final OOOOc Rule Must Strictly Limit States' Authority to Issue Plans that Deviate from Those Guidelines' Requirements Due to the Statute's "Remaining Useful Life" Provision.

In issuing its OOOOc guidelines, EPA must ensure that any state plans submitted are rigorous and that safeguards are in place to ensure those performance standards do not fall short of EPA's guidelines. The language, structure, and history of the Clean Air Act make abundantly clear that EPA must set binding emission reduction requirements in its existing source guidelines, and that state plans may allow less effective emission standards only where a particular affected source with unique circumstances can demonstrate to the state, and the state can demonstrate to EPA, that need for a case-specific variance.

It is true, of course, that respective provisions under section 111 that govern new and existing sources differ in terms of structure. Under section 111(b), EPA itself establishes performance standards for new sources and applies them directly to affected units; states are not involved in this process unless they specifically seek and receive approval from EPA under section 111(c) to administer new source standards.[1079] Section 111(d), by contrast, operates under a cooperative federalism framework, in which EPA first issues emission guidelines for categories of existing sources and states then adopt plans establishing standards of performance consistent with EPA's guidelines.[1080] EPA must approve "satisfactory" state plans and adopt and implement federal plans for states whose plans fall short or that decline to participate.[1081]

Under the statute, it is EPA's responsibility to specify the minimum degree of emission limitation to be incorporated in standards of performance. Section 111(a)(1) requires "*the Administrator*" to determine both the "best system of emission reduction" *and* the "achievable" "degree of emission limitation" therefrom. That federal minimum emission limitation provides states and EPA with the "substantive… criteria"[1082] for determining whether a state plan is "satisfactory."[1083] State-issued standards of performance, in turn, translate EPA's technical determination of what pollution reductions are "achievable" into an enforceable emission limit that regulated sources cannot exceed. Accordingly, EPA's regulations provide that a "standard of performance" must include "a legally enforceable regulation setting forth an allowable rate or limit of emissions into the

[1079] 42 U.S.C. §§ 7411(b)(1)(B), (c).
[1080] *Id.* § 7411(d)(1); *see also Am. Electric Power Co.*564 U.S. 410, 424 (2011) ("For existing sources, EPA issues emissions guidelines; in compliance with those guidelines and subject to federal oversight, the States then issue performance standards for stationary sources within their jurisdiction.").
[1081] 42 U.S.C. § 7411(d)(1), (2).
[1082] 40 Fed. Reg. at 53,342-43 (Nov. 17, 1975).
[1083] 42 U.S.C. §7411(d)(2).

atmosphere, or prescribing a design, equipment, work practice, or operational standard, or combination thereof."[1084]

EPA's implementing regulations for section 111 have consistently recognized the agency's obligation to establish the minimum stringency level for state-issued standards of performance.[1085] The regulations define "emission guideline" in terms that mirror Section 111(a)(1): as an emission limit reflecting the degree of emission limitation achievable through the EPA-determined "best system."[1086] In turn, standards of performance in a satisfactory state plan must be "no less stringent than the corresponding emission guideline(s)."[1087]

These implementing regulations directly reflect the text of section 111, which commands EPA to establish a procedure under section 111 that is "similar to that provided by section 7410 of this title."[1088] Under sections 108 to 110 of the statute, EPA establishes mandatory national ambient air quality standards ("NAAQS") for specific pollutants,[1089] which states then translate into plans that have binding effects on emission activities that occur within their borders.[1090] EPA must then either approve or reject (in whole or in part) state-submitted plans based on whether or not they satisfy the federal NAAQS.[1091] Similarly, under section 111, EPA's guidelines establish mandatory emission reduction requirements for existing stationary sources in a listed source category, states translate those requirements into enforceable standards for sources within their borders, and EPA must approve or reject those state plans based on whether or not they adhere to the federal requirements.[1092] Indeed, if EPA's guidelines did not provide clear and binding requirements to which state plans must adhere, there would be no manageable standards either for EPA to determine whether a state plan was "satisfactory"[1093] or for courts to review EPA's approval or denial of such plans.

Section 111(d) is not entirely devoid of flexibility, however. To account for the fact that the fleet of existing sources within a given category may vary significantly in numerous regards, EPA's implementing regulations permit the agency to "specify different degrees of emission limitation or compliance times or both for different sizes, types, and classes of designated facilities when costs of control, physical limitations, geographical location, or similar factors make subcategorization appropriate."[1094] Thus, EPA can approve a state plan with a package of performance standards that differ from the emission limits specified in the guidelines if the agency determines that the state's standards will produce at least as much emission reduction as a plan whose standards conformed to those emission limits. The statute also allows for variances for particular sources that derogate from that overall degree of emission reduction in specified extenuating circumstances. Hence,

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[1084] 40 C.F.R. §60.21a(f).
[1085] 40 Fed. Reg. 53,340; 84 Fed. Reg. at 32,575.
[1086] 40 C.F.R. §60.21a(e).
[1087] *Id.* §60.24a(c).
[1088] 42 U.S.C. § 7411(d)(1).
[1089] 42 U.S.C. § 7408(a).
[1090] *Id.* § 7410(a).
[1091] *Id.* § 7410(c).
[1092] 42 U.S.C. § 7411(d)(1).
[1093] *Id.* § 7411(d)(2)(A).
[1094] 40 C.F.R. 60.22a(b)(5).

section 111(d)(1) permits states to "take into consideration" a source's "remaining useful life" and "other factors" when "applying" a standard of performance to a "particular source."[1095] This clause (and its implementing regulation that appears at 40 CFR § 60.24a(e)) allows states to issue variances from a standard of performance if a particular source exhibits special characteristics warranting a different standard. The state must include any such variances in its plan and demonstrate to EPA that those specific characteristics are present.

It is critical to note, however, that section 111(d) does *not* permit or require a state to grant, or EPA to approve, variances for all sources merely because they have a short remaining useful life, nor does it provide that the state and EPA must tailor each source's emission reduction obligations to reflect its remaining useful life. Rather, under the RUL clause, sources are entitled to have states "consider[]" their arguments for lesser requirements based on remaining useful life or other factors, but states (and EPA) have the discretion to find those arguments unpersuasive. This is clear in EPA's implementing regulations, which permit a state to set a different standard for a specific source only if the state "demonstrates" a need based on "plant age, location, or basic process design," "[p]hysical impossibility of installing necessary control equipment," or "[o]ther factors specific to the facility…that make application of a less stringent standard…significantly more reasonable."[1096] And EPA must approve any such demonstration of need before approving a state plan as "satisfactory."[1097] In other words, the mere fact that an affected source may be of advanced age, or have unusual characteristics, does not in and of itself permit a state to grant a variance or require EPA to approve any such variance. Rather, the source must show some specific *reason* why those characteristics would justify a more lenient standard.

With regard to the oil and gas sector, EPA correctly recognizes that existing sources—even units with a short remaining useful life—are unlikely to be able to show sufficient reasons justifying a variance from otherwise applicable requirements. As the agency notes,

> that the oil and natural gas industry is unique such that the general approach to considering remaining useful life and other factors in the implementing regulations may not be an ideal fit. For example, the sheer number and variety of designated facilities in the oil and natural gas industry could make a source-specific (or even a class-specific) evaluation of remaining useful life and other factors extremely difficult and burdensome for States that want to undertake a demonstration. In addition, the presumptive standards for these designated facilities generally entail fewer major capital expenses compared with other industries for which EPA has previously issued EG under CAA section 111(d), and many of the proposed presumptive standards generally take the form of design, equipment, work practice, or operational standards rather than numerical emission limitations. Further, in proposing the presumptive standards for existing sources, the EPA has deliberately included certain flexibilities (e.g., in cases of technical infeasibility) such that the EPA believes the presumptive standards should be achievable and cost-effective for a wide variety of facilities across the source category. Given these facts, the

[1095] 42 U.S.C. §7411(d)(1).
[1096] 40 C.F.R. § 60.24a(e); *id.* § 60.24(f).
[1097] *See id.* § 60.27a(c)(2).

> EPA believes that it would likely be difficult for States to demonstrate that the presumptive standards are not reasonable for the vast majority of designated facilities.[1098]

Joint Environmental Commenters fully agree with these observations.

The central term in section 111(d)'s variance provision—"remaining useful life"—is, in fact, a term of art used in engineering and accounting that refers to "an estimate of the number of remaining years that a component in a production line is estimated to be able to function in accordance with its intended purpose before warranting replacement."[1099] Congress's primary motivation for using this language in section 111(d) was to avoid the problem of stranded assets, which are "assets that have suffered from unanticipated or premature write-downs, devaluation or conversion to liabilities."[1100] In environmental regulation, this may occur when (for example) an existing source nearing the end of its useful life becomes subject to new regulations that require the installation of expensive pollution control equipment. If the source then retires soon thereafter due on account of age, the control equipment will likely be stranded, since it will have been rendered useless before long before that equipment's useful life has expired and its operator has fully paid off the capital it invested in the device.

This can be a significant issue for capital-heavy industries. To avoid this kind of dilemma in the context of section 111(d), Congress enacted the RUL provision. Yet Congress clearly did *not* intend to grant a free pass—or even a more lenient pass—to aging sources simply because they were old. Rather, there must be some indication that applying the governing standard to this particular source would result in unreasonable (and particularly wasted) costs. As EPA noted, it is highly unlikely that sources in the oil and gas industry will be able to demonstrate that remaining useful life and other specific factors make it "significantly more reasonable" to apply a more lenient standard. This sector is different in several regards from many or most other industries regulated under section 111. The emitting sources themselves are much more numerous, much smaller, and, in most cases, less expensive than sources in other industries, and often rely on emission reduction practices that bear little resemblance to the kinds of expensive pollution control technologies that are often found in other industries, and oil and gas sector equipment often depreciates much more quickly than do the kinds of large-scale, capital-intensive infrastructure that exist in other industries.[1101]

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[1098] 86 Fed. Reg. at 63,251.

[1099] Kang, et al,. *Remaining Useful Life (RUL) Prediction of Equipment in Production Lines Using Artificial Neural Networks*, SENSORS (Basel), 2021 Feb 21(3): 932, https://www.ncbi.nlm.nih.gov/pmc/articles/PMC7866836/.

[1100] Lloyd's, Stranded Assets, https://www.lloyds.com/strandedassets (last visited Jan. 28, 2022). *See also, e.g.*, 80 Fed. Reg. 64,662, 64872 (Oct. 23, 2015) ("Congress intended the remaining useful life provision to provide a mechanism for states to avoid the imposition of unreasonable retrofit costs on existing sources with relatively short remaining useful lives, a scenario that could result in stranded assets.").

[1101] Internal Revenue Service Pub. 946, "How to Depreciate Property" (2020), *available at* https://www.irs.gov/forms-pubs/about-publication-946; Deloitte, Oil and gas taxation in the United States (2013), https://www2.deloitte.com/content/dam/Deloitte/global/Documents/Energy-and-Resources/dttl-er-US-oilandgas-guide.pdf ("Many assets used by oil and gas producers to drill wells and produce oil and gas have a recovery period of seven years.")

Work practices for other equipment in the oil and gas industry may require operators to purchase and install new equipment, but these control methods are often much less expensive than in other industries and, in many cases, allow the operator to turn a net profit through conserved gas. For example, the LDAR standards require very few upfront capital costs, almost none of which are tied to a specific facility. Instead, an operator can simply contract with an LDAR provider who will conduct surveys across the operator's facilities. If one site shuts down, the operator experiences no loss or stranded assets. Even in the situation where an operator decides to conduct in-house LDAR surveys and purchases monitoring equipment, that equipment would not become a stranded asset and is not tied to a particular well site. The operator could continue using the monitoring equipment at other sites or sell it and recover resale value.

As another example, OOOOc's proposed requirements for reciprocating compressors would require operators either to replace rod packing when measured leak rate exceeds 2 scfm based on the results of annual monitoring, or to capture and route rod packing emissions to a process through a closed vent system under negative pressure.[1102] According to EPA, rod packing replacements would entail annual capital costs of approximately $1,700 to $2,300, which is orders of magnitude lower than control equipment for many other industries. Moreover, these costs can generally be recouped entirely through conserved gas within 6-to-24 months,[1103] and EPA projects that its requirements for reciprocating compressors will have net *negative* costs.[1104] As yet a third example, OOOOc's proposed standards for centrifugal compressors require operators to reduce emissions by 95% through use of a wet-seal degassing system. EPA reports these systems as having capital costs around $33,000 per compressor—still four orders of magnitude lower than an FGD—with a payback period of just one to five months.[1105] Moreover, it may be possible for operators to reuse such degassing systems—and potentially other pollution control equipment, like vapor recovery units—for newly installed facilities once the older facilities retire.

Thus, in determining how to apply the remaining useful life provision to the oil and gas source category, EPA should take into account the following three considerations regarding the extent to which states should be permitted to grant a variance: 1) Is the cost of the new equipment so relatively negligible that variances simply should not be granted, regardless of a source's remaining useful life? 2) Do cost savings achieved through recovered gas either partially or totally offset the control equipment's cost within the source's remaining useful life window, and if so, should that mean that the stranded asset problem doesn't arise and that no variances should be granted? 3) Can the control equipment be used at another emissions source after the original emissions source retires, and if so, should that option obviate the need for a variance? As for point 1, it is worth noting that the OOOOa rule included a formula for determining when a capital expenditure has occurred.[1106] This formula appears to pertain to whether or not a source can be considered "modified," but EPA should consider whether it is also appropriate for establishing a

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[1102] 86 Fed. Reg. at 63,121.
[1103] *See* EPA, Reducing Methane Emissions From Compressor Rod Packing Systems (Oct. 2006), https://www.epa.gov/sites/default/files/2016-06/documents/ll_rodpack.pdf.
[1104] RIA at 2-36.
[1105] *See* EPA, Wet Seal Degassing Recovery System for Centrifugal Compressors (2014), https://www.epa.gov/sites/default/files/2016-06/documents/capturemethanefromcentrifugalcompressionsealoildegassing.pdf.
[1106] *See* 40 C.F.R. § 60.5430a.

monetary threshold below which states should not be permitted variances even if a source retires before the depreciation schedule for the new control equipment has expired.

Furthermore, EPA must prohibit states from accounting for sources' profitability when determining whether to issue variances. Nothing in the Clean Air Act permits the agency to accommodate aging sources and prioritize their ability to achieve a profit, even after many years of operation, over environmental considerations. Particularly for sources such as aging wells that produce only marginal amounts of oil or gas decades after being drilled, EPA must not allow these operators to be given relaxed standards simply due to low profit margins. Any source that is so marginal such that (for example) spending several thousand each year for leak detect and repair monitoring would eliminate its ability to turn a profit should not be operating.

Moreover, a source operator's subjective opinion about the extent of the source's remaining useful life should play no role in any determination as to whether the source should receive a variance. Whether a source is "useful" from an operator's standpoint will in virtually all cases be based on its profitability rather than its actuarial value as an engineering asset, which is what section 111(d)'s RUL provision is intended to reflect. As such, profitability—and the factors that influence it, such as oil and gas prices, the amount of recoverable product, and other considerations—are simply irrelevant to whether a control requirement would be objectively unreasonable in a particular, limited instance or would result in stranded assets. Rather than relying on operators' own estimations of the remaining useful life of their equipment, EPA should refer to IRS depreciation schedules to establish clear and objective lifetimes for each type of equipment. The agency should also define a reasonable—and reasonably limited—number of years left on a source's actuarial lifetime during which it can claim a variance based on RUL, and even in those cases, the source should only be granted a variance if it can demonstrate particular hardship that would result from compliance based on the short RUL window; again, marginal profitability should play no role in this determination.

Critically, once a source's IRS-defined depreciation period has expired, it should no longer be permitted to qualify for an RUL-based variance. Operating equipment past the point in which the federal government considers it useful is poor engineering practice and often results in inefficient operation and, frequently, excess emissions. To allow operators to benefit from a variance under such circumstances would not only reward the worst performers, it would incentivize operators to continue using old and failing equipment for as long as possible rather than invest in newer and more efficient infrastructure that would have no option for an RUL variance. This would defeat the entire purpose of section 111(d) controls for existing sources.

Where a source does qualify for a variance based on RUL, EPA must require that the source agree to a federally enforceable retirement date that reflects the expiration of the unit's IRS depreciation schedule. Even EPA's 2019 Affordable Clean Energy ("ACE") rule for existing fossil fuel-fired power plants, which took an inappropriately expansive view of section 111(d)'s variance provision and which many of the Joint Environmental Commenters vigorously objected to and challenged in court, included a requirement that any source benefitting from the RUL provision "specify the exact date by which the source's remaining useful life will be zero" and that such source's

"associated retirement date will be federally enforceable upon approval by the EPA."[1107] Although we strongly object to the ACE Rule's fundamental interpretation of the RUL provision, we believe this particular feature of the rule was appropriate. We therefore urge EPA to include in the final OOOOc rule this same requirement that source's receiving an RUL-based variance submit to a federally enforceable retirement date linked to the years remaining in the source's IRS depreciation schedule. If no years remain, it should not be eligible for an RUL-based variance.

Finally, EPA should revise its implementing guidelines to more precisely define the "other factors" that are discussed in section 111(d)(1). The statute's remaining useful life provision specifies that states must be permitted to take into consideration sources' remaining useful life "*among other factors*."[1108] This language suggests that the agency must permit states to issue variances for at least *some* reasons other than remaining useful life, without specifying what or how numerous those factors should be. EPA's current implementing regulations permit states to grant variances based on a "demonstration' of the following factors:

> (1) Unreasonable cost of control resulting from plant age, location, or basic process design;
>
> (2) Physical impossibility of installing necessary control equipment; or
>
> (3) Other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable.[1109]

This regulatory text should be revised to offer more specific and useful directions as to what may and may not factor into a state's decision to grant a variance to a particular source. The third factor in this list is particularly vague and merely parrots, rather than clarifies, the reference to "other factors" in the statutory text. The agency has stated that it "intends to provide further clarification on the general process and requirements for accounting for remaining useful life and other factors, including on the reasonableness aspect of the required demonstration, via a rulemaking to amend the implementing regulations in the near future."[1110] Joint Environmental Commenters support this effort and encourage EPA to set clearer parameters to govern when variances may be granted. As discussed previously, however, the oil and gas industry has several unique features that justify limiting the usual scope of the variance provision in certain regards, and the implementing regulations make clear that "each emission guideline may include specific provisions in addition to or that supersede requirements of this subpart."[1111]

Thus, in the context of the OOOOc rulemaking in particular, EPA should identify a specific and more limited set of circumstances in which states may issue variances under this provision. First, as noted above, the agency should define narrow and well-defined circumstances in which the

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[1107] 84 Fed. Reg. 32,520, 32,558 (July 8, 2019).
[1108] 42 U.S.C. § 7411(d) (emphasis added).
[1109] 40 C.F.R. § 60.24a(e)(1)-(3).
[1110] 86 Fed. Reg. at 63,251.
[1111] *Id.* § 60.20a(a)(1).

likelihood of stranded assets might permit variances, incorporating a capital expenditure threshold, an operator's ability to defray compliance costs through sale of conserved gas, and the operator's ability to use control equipment at new sources after an old source retires. Second, the agency should also retain point two above regarding physical impossibility, which is a reasonable limitation. Finally, OOOOa already includes a number of limited exceptions in the requirements themselves based on (for example) safety or temperature considerations. For instance, LDAR repair requirements are relaxed when such repairs cannot be made safely, and sources on the Alaskan North Slope are exempt from certain requirements. In its emission guidelines for existing sources, EPA should clarify that these exemptions are among the "other factors" states may consider when granting variances.

## VI. Impacts of Standards / Cost-Benefit Analysis

EPA's regulatory impact analysis understates the benefits of its proposal. While Joint Environmental Commenters support the use of the Interagency Working Group's February 2021 Social Cost of Methane and its global perspective, it understates the true cost of methane. In addition, EPA has not attempted to monetize the proposal's non-climate health impacts, so those significant benefits are left out of the calculations of net benefits for the regulatory options.

### A. The Social Cost of Methane

The Social Cost of Methane (SC-CH4) measures the net economic harm to society due to climate change for every additional ton of methane emitted, or the economic value of avoiding those emissions. The SC-CH4 is meant to encompass the value of all climate change impacts including human health effects, property damage, conflict, and changes to ecosystem services.[1112]

The SC-CH4 is appropriate to use in cost-benefit analyses in the finalized rule. The SC-CH4 does not impose an upper limit on the costs EPA can determine are reasonable under Section 111. However, because even the most accurate SC-CH4 reflects the societal value of reducing methane emissions and represents net benefits to society, the SC-CH4 is by definition reasonable and is thus a useful measure in determining the cost-effectiveness of a rule.

In this section the Joint Commenters review the development of the SC-CH4 since its inception, explain why EPA's current proposal uses a legally supported SC-CH4 that is based upon the best estimates to date, and urge the agency in its final rule to use an updated SC-CH4 that better reflects the true social cost of methane.[1113]

#### *i. The Proposal*

The EPA estimated the global social benefits of CH4 emission reductions expected from the proposal using the SC-CH4 values presented in the "Technical Support Document: Social Cost of

[1112] Proposal, 559.
[1113] Beyond the discussion here, many of the joint commenters have also signed onto a comment submitted by the Institute for Policy Integrity which discusses the legal issues associated with the social cost of methane mehtanes in more depth.

Carbon, Methane, and Nitrous Oxide Interim Estimates under EO 13990 (IWG 2021)" published in February 2021 by the Interagency Working Group on the Social Cost of Greenhouse Gases (IWG). These SC-CH4 estimates are interim values developed under E.O. 13,990 for use in agency cost-benefit analyses.

The IWG was first created in 2009 to promote inter-agency consistency in evaluating the social cost of greenhouse gasses and for many years used the same methodologies that were employed by the IWG in 2021 (including global costs and low discount rates). In 2017, President Trump issued E.O. 13,783, which disbanded the IWG and directed agencies to estimate the social cost of GHGs (SC-GHG) used in regulatory analyses consistent with the guidance contained in OMB's Circular A-4, which the Trump Administration interpreted as requiring cost-benefit analyses that considered only the domestic impacts of climate change and a higher discount rate. In 2020, President Biden issued E.O. 13,990 to replace E.O. 13,783. E.O. 13,990 re-established the IWG and tasked it with reviewing the SC-GHG estimates used by the Trump administration and publishing interim estimates that better reflect the full impact of GHG emissions, including global damages and more appropriate discount rates, until updated estimates can be developed in 2022.

The IWG's 2021 SC-CH4 (and the IWG's 2021 SC-GHGs more broadly) is based on the most comprehensive modeling platforms available and reflects years of careful development, peer-reviewed research, and numerous revisions by the federal agencies that constitute the IWG.[1114] Although this metric should be understood as a conservative floor for the true social cost of methane—which is almost certainly much higher than the IWG SC-CH4 indicates—it is nevertheless the best and most representative set of estimates for the social cost of methane that the federal government has produced since the IWG's 2016 estimates (made immediately before the Trump administration disbanded the IWG in 2017).

As acknowledged by EPA, 2021 RIA at 3-13, the SC-CH4 provides an appropriate *minimum* benchmark for determining that costs may be considered reasonable with regard to cost per ton of pollution abated.

*ii. EPA's Finalized Rule Should Maintain a Global Perspective in its Social Cost of Methane Calculation*

In the RIA for the proposal, EPA explains that its analysis incorporates the global – rather than merely domestic – costs of methane pollution.[1115] The RIA notes that the 2021 IWG report concluded that the calculations used in accordance with E.O. 13,783 under the Trump

[1114] The IWG SC-CH4 is an inflation-adjusted estimate originally estimated by Marten et al. (2015). The Marten et al. (2015) estimate relies on sophisticated Integrated Assessment Modeling (IAM), which allows researchers to directly estimate the social cost of methane. As the name suggests, the assumptions and inputs used in IAMs extend beyond climate science. These models assess climate impacts through a damage function that relates average global atmospheric temperature change to socio-economic impacts across major sectors. The damage functions used in Marten et al. (2015) include climate impacts as well as climate-related damages to human health and amenities, agriculture, and forestry. *See* Marten, Alex L, Elizabeth A Kopits, Charles W Griths, Stephen C Newbold, and Ann Wolverton. "Incremental CH4 and N2O Mitigation Benefits Consistent with the US Government's SC-CO2 Estimates." Climate Policy, 15 (2015): 272-298.
[1115] RIA, 3-6.

Administration failed to reflect the full impact of GHG emissions because they didn't employ a global perspective. The IWG found that a global perspective was required to accurately calculate SC-CH4 for two reasons. First, it explained that climate impacts occurring outside U.S. borders can directly and indirectly affect U.S. interests, including U.S. citizens and assets located abroad, international trade, tourism, political destabilization, and global migration. Second, it noted that assessing the benefits of U.S. GHG mitigation activity requires considering how that activity may spur mitigation by other countries, since those international mitigation actions will provide a benefit to U.S. citizens and residents by reducing climate impacts in the U.S.

The IWG and EPA have correctly recognized that methane is a global pollutant whose economic impacts can only be fully accounted for by considering its effects both within the United States and abroad. Methane emissions have direct effects on U.S. citizens and assets located abroad, the U.S. economy, international trade and demand for U.S. products, tourism, economic and political destabilization, humanitarian crises, and global migration. The most recent National Climate Assessment explains in detail how the international effects of climate change impact U.S. interests:

> The global impacts of climate (climate change, variability, and extreme events) are already having important implications for societies and ecosystems around the world and are projected to continue to do so into the future. There are specific U.S. interests that can be affected by climate-related impacts outside of U.S. borders, such as climate variability (for example, El Niño/La Niña events), climate extremes (for example, floods resulting from extreme precipitation), and long-term changes (for example, sea level rise). These interests include economics and trade (Key Message 1), international development and humanitarian assistance (Key Message 2), national security (Key Message 3), and transboundary resources (Key Message 4)…. [T]hese four topics…can also affect each other. For example, climate-related disasters in developing countries not only have significant local and regional socioeconomic impacts, but they can also set back U.S. development investments, increase the need for U.S. humanitarian assistance, and affect U.S. trade and national security. U.S. citizens have long been concerned about the welfare of those living beyond U.S. borders and their vulnerability to the global impacts of climate.[1116]

Furthermore, there is a national interest in encouraging other jurisdictions to fully account for the costs of climate pollution, which would be put at risk if EPA were to focus solely on domestic costs. As EPA notes, methane and other climate pollutants have global impacts in that actions taken by other countries to reduce greenhouse gas pollution inevitably have benefits for the United States and vice-versa. Because all countries are affected by greenhouse gas pollution emitted anywhere, optimal reductions of pollutants and of climate impacts in the U.S. can only be achieved if every country takes into account the full, global costs of its pollution. As a result, the only way for countries to agree upon mutually beneficial reductions targets within international agreements is for countries to consider levels justified beyond their own domestic benefits. Encouraging the

[1116] Murth et al., National Climate Assessment, Chapter 16: Climate Effects on U.S. International Interests (November 2018), https://nca2018.globalchange.gov/chapter/16/.

international community to use global costs would bring about these benefits and would entail reduced climate impacts within the U.S.

In fact, the U.S. is already seeing such benefits[1117] as a result of other countries accounting for the global impacts of methane and other climate pollutants.[1118] If EPA were to use the "domestic-only" approach used under the Trump Administration, that would likely encourage other countries to follow suit, and those reciprocity benefits would be lost. Citing extensive academic literature, the National Academies has recognized that these reciprocity effects are one reason to use a global measure of the social cost of climate pollution.[1119]

The alternative approach – domestic-only social cost figures–has been described by leading economists in the field of climate economics (including the late Nobel Prize-winning economist and game theory pioneer Kenneth Arrow) as "deeply misleading" in that it "wrongly assume[s] that the United States is an island unaffected by migration, national security, global economic disruptions and other cross-border externalities."[1120] Moreover, OMB and the federal agencies in the IWG concluded in the 2021 IWG interim report that the development of a merely domestic SC-GHG is complicated by "incomplete" literature.[1121] Similarly, William Nordhaus, the developer of the DICE model (one of the three integrated assessment models underlying the SC-GHG estimates), has cautioned that "regional damage estimates are both incomplete and poorly understood," and "there is little agreement on the distribution of the SCC by region."[1122] Notably, a 2017 report by the National Academies specifically calls out these limitations, concluding that "[c]limate damages to the United States cannot be accurately characterized without accounting for consequences outside U.S. borders."[1123] As the report explains:

> Correctly calculating the portion of the SC-CO2 that directly affects the United States involves more than examining the direct impacts of climate that occur within the country's physical borders …. As the IWG noted (Interagency Working Group on the Social Cost of Carbon, 2010), climate change in other regions of the world could affect the United States through such pathways as global migration, economic

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[1117] See Peter Howard & Jason Schwartz, Foreign Action, Domestic Windfall: the U.S. Economy Stands to Gain Trillions from Foreign Climate Action 11 Inst. for Policy Integrity, (Nov. 2015) http://policyintegrity.org/files/publications/ForeignActionDomesticWindfall.pdf (estimating that direct U.S. benefits from global climate policies already in effect are over $2 trillion through 2030).

[1118] See Peter Howard & Jason Schwartz, Think Global: International Reciprocity as Justification for a Global Social Cost of Carbon, 42 COLUMBIA J. ENVTL. L. 203, 223 (2017) (noting that Canada, Mexico, Sweden, Germany, the United Kingdom, Norway, and the European Union have all adopted global social cost metrics, and that many other jurisdictions have adopted policies that put a price on climate pollution consistent with global social cost metrics).

[1119] National Academies of Sciences, Engineering, and Medicine, Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide 53 (2017), available for free download at https://www.nap.edu/catalog/24651/valuing-climate-damages-updating-estimation-of-the-social-cost-of. The National Academies further notes that such reciprocity impacts should be accounted for in evaluating the impacts of climate pollution on the United States. Id. at 9.

[1120] Richard L. Revesz et al., The Social Cost of Carbon: A Global Imperative, 11 Rev. of Envt'l Econ. and Policy 172, 173 (2017) http://policyintegrity.org/files/publications/REEP_SCC_2017.pdf

[1121] IWG Report 2021, at 16.

[1122] William Nordhaus, Revisiting the Social Cost of Carbon, 114 PNAS 1518, 1522 (2017)

[1123] National Academies 2017 at 53 (emphasis added).

> destabilization, and political destabilization. In addition, the United States could be affected by changes in economic conditions of its trading partners: lower economic growth in other regions could reduce demand for U.S. exports, and lower productivity could increase the prices of U.S. imports. The current SC-IAMs do not fully account for these types of interactions among the United States and other nations or world regions in a manner that allows for the estimation of comprehensive impacts for the United States.[1124]

*iii. EPA was Correct to Abandon a 7% Discount Rate*

EPA has adopted social cost of methane estimates calculated at discount rates of 2.5%, 3%, and 5%, abandoning a 7% capital-based discount rate used by the Trump Administration as inappropriate for climate effects, consistent with the IWG's current recommendations.[1125] While an even lower range of discount rates would be more appropriate, *see infra* subsection v, abandoning the 7% rate better aligns with what the expert consensus recommends for analyzing the impacts of a high-risk, long-term, multi-generational crisis such as global climate change, and is appropriate for a few reasons in particular:

First, Circular A-4 and economic theory suggest that the correct framework for analyzing climate effects is the discount rate on the consumption rate of interest (which Circular A-4 estimates at 3%, but which the latest data shows is much lower, *see infra* subsection v), *not* a discount rate based on the private return to capital (which the 7% rate represents). Circular A-4 explains that "[w]hen regulation primarily and directly affects private consumption . . . *a lower discount rate is appropriate.*"[1126] Because climate change is expected to mostly affect large-scale consumption, as opposed to capital investment,[1127] a lower discount rate is appropriate and a 7% discount rate is inappropriate. Further, the National Academies of Sciences has referred to the consumption rate

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[1124] National Academies 2017, at 52-53.

[1125] RIA 3-9 to 3-10. To reflect tipping-point scenarios for climate change, EPA also considers the 95th percentile of estimates based on a 3% discount rate, consistent with the IWG's approach to the SC-GHG. *Id.*

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[1127] Maureen Cropper, How Should Benefits and Costs Be Discounted in an Intergenerational Context?, 183 RESOURCES 30, 33 (2013) ("There are two rationales for discounting future benefits—one based on consumption and the other on investment. The consumption rate of discount reflects the rate at which society is willing to trade consumption in the future for consumption today. Basically, we discount the consumption of future generations because we assume future generations will be wealthier than we are and that the utility people receive from consumption declines as their level of consumption increases. . . . The investment approach says that, as long as the rate of return to investment is positive, we need to invest less than a dollar today to obtain a dollar of benefits in the future. Under the investment approach, the discount rate is the rate of return on investment. If there were no distortions or inefficiencies in markets, the consumption rate of discount would equal the rate of return on investment. There are, however, many reasons why the two may differ. As a result, using a consumption rather than investment approach will often lead to very different discount rates."); see also Richard G. Newell & William A. Pizer, Uncertain Discount Rates in Climate Policy Analysis, 32 ENERGY POL'Y 519, 521 (2004) ("Because climate policy decisions ultimately concern the future welfare of people—not firms—the consumption interest rate is more appropriate.").

of interest as the "theoretically correct discount rate" where benefits and costs are measured in consumption-equivalent units, as they are in the models underlying the social cost of methane.[1128]

Second, EPA is justified in using a range of lower discount rates considering the long time horizon of climate effects and the uncertainty of damage magnitude. For one thing, according to an expert elicitation of over 1,100 economists in the field of climate economics, there is a growing consensus in favor of an initial discount rate of no greater than 2 to 3 percent and/or one that declines as time progresses. Ninety percent of the economists surveyed supported a discount rate of 5 percent or less in such circumstances.[1129] Similarly, the 2017 National Academies report observes that the IWG discount rates of 2.5, 3, and 5 percent were carefully selected to reflect economic theory and peer-reviewed literature, and that the majority of climate change impact studies cited in the Fifth Assessment Report of the Intergovernmental Panel on Climate Change "use an implied social discount rate of no more than 5 percent."[1130]

Circular A-4 also supports a lower discount rate for long-term situations like climate effects. Circular A-4 identifies an EPA rule with a 30-year timeframe of costs and benefits as an example of when a 7% discount rate may be used alongside a 3% rate,[1131] but greenhouse gas emissions will have effects for hundreds of years and have major impacts on future generations. Indeed, Circular A-4 states that "[s]pecial ethical considerations arise when comparing benefits and costs across generations," acknowledging that "[s]ome believe . . .that it is ethically impermissible to discount the utility of future generations."[1132] Although Circular A-4 still asserts that it is appropriate to discount costs and benefits that have intergenerational effects, it agrees that it is appropriate to use a "lower rate" in these circumstances than would otherwise apply and cites one paper calling for a discount rate of 1-3% for policies that have intergenerational impacts.[1133]

#### *iv. EPA Has Full Legal Authority to Apply the IWG's Approach to the Social Cost of Methane*

EPA should take the opportunity to clarify in its final rule the legal authority that supports its use of a global perspective and range of lower discount rates. The agency should first highlight the multitude of authorities that allow and support the use of a global calculation. For example, the National Environmental Policy Act (NEPA) requires agencies to "recognize the worldwide and long-range character of environmental problems" and to "lend appropriate support" to help

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[1128] National Academies 2017 at 28; see also Kenneth Arrow et al., Is There a Role for Benefit-Cost Analysis in Environmental, Health, and Safety Regulation?, 272 SCIENCE 221 (1996), available at https://www.science.org/doi/10.1126/science.272.5259.221 (explaining that a consumption-based discount rate is appropriate for climate change).

[1129] Peter Howard & Derek Sylvan, The Economic Climate: Establishing Expert Consensus on the Economics of Climate Change 21, Inst. Policy Integrity (Dec. 2015).

[1130] National Academies 2017 at 168. The social cost of methane used in the 2016 Rule reflected the same discount rates of 2.5, 3, and 5 percent that were approved by the IWG for the social cost of carbon. See 2016 RIA, at 1-8 n.1.

[1131] Circular A-4 at 34.

[1132] *Id.* at 35.

[1133] *Id. a*t 36 (citing Portney PR and Weyant JP, eds. (1999), *Discounting and Intergenerational Equity*, Resources for the Future, Washington, DC.).

"maximize international cooperation" when creating policies and regulations,[1134] mandates that have been recognized in multiple legal opinions.[1135] Although NEPA does not apply to EPA actions under the Clean Air Act, these court-endorsed principles nevertheless reflect the fact that it is sound and rational environmental policy for an agency to consider the global and long-range impacts of its actions. Moreover, the United Nations Framework Convention on Climate Change—to which the United States is a party[1136]— declares that national "policies and measures to deal with climate change should be cost effective so as to ensure global benefits at the lowest possible cost,"[1137] demonstrating an obligation to consider global economic costs.

Legal decisions on the social cost of greenhouse gasses also support EPA's discounting approach. In *Zero Zone v. Department of Energ*y, the Seventh Circuit upheld a Department of Energy regulatory analysis that considered hundreds of years of climate benefits but a shorter horizon for employment impacts, concluding that the difference in time horizons was justified because the rule "would have long-term effects on the environment but . . . would not have long-term effects on employment."[1138] *Zero Zone* also upheld the Department's use of a global social cost metric against an argument that only a domestic analysis was permitted. The court held that "climate change involves a global externality, meaning that carbon released in the United States affects the climate of the entire world. . . . national energy conservation has global effects, and, therefore, those global effects are an appropriate consideration when looking at a national policy."[1139] Similarly, in 2020, the U.S. District Court for the Northern District of California struck down as arbitrary the Bureau of Land Management's ("BLM") rescission of the Waste Prevention Rule in part because the agency had substituted the Working Group's peer-reviewed global estimates for ones that looked only at domestic effects.[1140] The global estimates, the court found, reflected "the best available

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[1134] 42 U.S.C. §4332(2)(F)

[1135] *EDF v. Massey,* 986 F.2d 528, 536 (D.C. Cir. 1993) ("Section 102(2)(F) further supports the conclusion that Congress, when enacting NEPA, was concerned with worldwide as well as domestic problems facing the environment. . . . Compliance with one of the subsections can hardly be construed to relieve the agency from its duty to fulfill the obligations articulated in other subsections."); *NRDC v. NRC*, 647 F.2d 1345, 1387 (D.C. Cir. 1981) (J. Robinson, concurring; J. Wilkey wrote for the Court, but there was no majority opinion) (concluding that even if a conflict with another statute prevents the agency from conducting an environmental impact statement, that "does not imply that NRC may ignore its other NEPA obligations," including the "provision for multinational cooperation" and the "policy of the United States with respect to the ecological well-being of this planet"; rather, the agency "should remain cognizant of this responsibility"); *Greene County Planning Bd. v. Federal Power Comm'n*, 455 F.2d 412, 424 (2d Cir. 1972) ("The Commission's 'hands-off' attitude is even more startling in view of the explicit requirement in NEPA that the Commission 'recognize the worldwide and long-range character of environmental problems' and interpret its mandate under the Federal Power Act in accordance with the policies set forth in NEPA.").

[1136] S. Treaty Doc. No. 102-38; S. Exec. Rept. No. 102-55.

[1137] U.N. Framework Convention on Climate Change art. 3(3), May 9, 1992, 1771 U.N.T.S. 107.

[1138] *Zero Zone v. Dept. of Energy*, 832 F.3d 654, 679 (7th Cir. 2016).

[1139] *Id.*

[1140] California v. Bernhardt, 472 F. Supp. 3d 573, 613 (N.D. Cal. 2020).

science about monetizing the impacts of greenhouse gas emissions,"[1141] whereas the domestic values had "been soundly rejected by economists as improper and unsupported by science."[1142]

### *v. The Proposal's Social Cost of Methane Understates the True Cost of Methane Pollution*

Although the IWG's 2021 SC-CH4 is the best and most representative set of estimates for the social cost of methane that the federal government has thus far produced, numerous experts, including EPA itself (*see* RIA 3-13), agree that all currently available estimates of social cost of GHGs (including the IWG's SC-CH4) are likely still too low.[1143] Proposed areas for revision include decreasing the discount rate to further account for the welfare of future generations, improving economic damage estimates, and updating the underlying climate science. For certain policy decisions, non-climate health impacts, such as methane damages to human health via ozone formation, should also be included.

Discount rates assess how much weight should be put on the welfare of future generations. Recent studies suggest that lower discount rates in the 1-3% range would be more appropriate given the long-time horizon of social cost estimates.[1144] If incorporated, lower discount rates could have a large impact on the IWG SC-CH4, which, as noted above, is currently estimated at discount rates of 2.5%, 3% and 5% (plus the 95% percentile values at 3 percent to reflect tipping points). One recent study by Carleton and Greenstone (2021) notes that simply updating the previous 2013 social cost of carbon (SCC) value for inflation and switching from a 3% to a 2% discount rate would increase the SCC from about $50 to $125 per metric ton of $CO_2$.[1145] A similar adjustment would also apply to the SC-CH4.

Second, current social cost estimates only consider a fraction of the physical, ecological, and economic damages associated with climate change.[1146] Some newer IAMs, such as the Spatial Empirical Global-to-Local Assessment System (SEAGLAS) model, are improving on previous IAM estimates by assessing a wider range of climate damages at finer spatial resolutions. As summarized in Hsiang et al. (2017), SEAGLAS relies on empirical evidence to estimate US

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[1141] *Id.* at 611.

[1142] *Id.* at 613; *See also* *Center for Biological Diversity v. NHTSA*, 538 F.3d 1172, 1198-1201 (9th Cir. 2008) (agency "cannot put a thumb on the scale by undervaluing the benefits and overvaluing the costs of more stringent standards" by failing to "monetize or quantify the value of carbon emissions reduction"); *Zero Zone*, 832 F.3d at 677-679 (agency reasonably relied on IWG's estimates to calculate global benefits of greenhouse gas reductions from energy efficiency rules).

[1143] Wagner, G., Anthoff, D., Cropper, M., Dietz, S., Gillingham, K. T., Groom, B., Kelleher, J. P., Moore, F. C., & Stock, J. H. (2021). Eight priorities for calculating the social cost of carbon. Nature, 590(7847), 548–550. https://doi.org/10.1038/d41586-021-00441-0

[1144] Drupp, M. A., Freeman, M. C., Groom, B., & Nesje, F. (2018). Discounting Disentangled. *American Economic Journal: Economic Policy*, *10*(4), 109–134. https://doi.org/10.1257/pol.20160240

[1145] Carleton, Tamma and Greenstone, Michael, Updating the United States Government's Social Cost of Carbon (January 14, 2021). University of Chicago, Becker Friedman Institute for Economics Working Paper No. 2021-04, Available at SSRN: https://ssrn.com/abstract=3764255

[1146] TSD at 4.

county-level economic damages from climate change for the following areas: agriculture, crime, coastal storms, energy, human mortality, and labor.[1147]

Moreover, from a physical science standpoint, these studies do not fully capture complexities in the atmospheric gas cycle. The IWG SC-CH4 would be improved by simply updating the outdated IPCC Third Assessment (AR3) estimate of radiative forcing from methane with the higher warming estimate in the AR5. Other issues are more challenging to capture in social cost estimates and may not always result in upward revisions. This includes assumptions around GHG lifetime decay rates and indirect effects on atmospheric ozone and water vapor concentrations. Such inputs are uncertain and are managed differently across climate models.

Finally, the SC-CH4 does not incorporate non-climate impacts on local health. Recent epidemiologically-derived research suggests that such non-climate impacts from methane may be significant. In particular, methane-induced changes in surface ozone affect air quality, human health, and agricultural productivity in ways that have significant costs. The Sarofim et al. (2015)[1148] and Shindell (2015)[1149] studies aim to extend the methodology underlying the IWG SC-CH4 , resulting in cost ranges that would be much higher than current values. EPA and the IWG agree that, taken together, these features suggest that the interim SCM estimates used in this proposed rule likely underestimate the damages from methane.[1150]

### B. EPA should quantify and monetize the Proposal's non-climate health impacts.

EPA should consider and account for, in as much detail as possible, the many significant non-climate health benefits of the proposal. Wherever possible, health benefits should be quantified and monetized. In cases of high levels of uncertainty, EPA should quantify and monetize these benefits using conservative estimates rather than not monetizing or quantifying them at all (which is the agency's current approach), and should present them alongside a discussion of any limitations in the analysis. To the extent that EPA is truly unable to monetize the proposal's non-climate health impacts, it must emphasize that its regulatory impact analysis underestimates the overall benefits of the proposal as a result.

Although the proposal's monetized climate benefits far outweigh its costs irrespective of non-climate health impacts, it is important to stress the sheer magnitude of the proposal's net benefits by also including monetized non-climate health benefits. Namely, the proposal would result in reduced emissions of methane, VOCs, and HAPs, yielding significant non-climate health benefits.[1151] However, the proposal currently provides a less-than-thorough assessment of these benefits. EPA summarizes them as follows: "Under the proposed NSPS OOOOb and EG OOOOc, the EPA *expects* that VOC emission reductions will improve air quality and *are likely to improve*

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[1147] Hsiang et al. "Estimating economic damage from climate change in the United States." Science 30 Jun 2017: Vol. 356, Issue 6345, pp. 1362-1369. DOI: 10.1126/science.aal4369
[1148] Sarofim Marcus C., Waldhoff Stephanie T. and Anenberg Susan C.. "Valuing the Ozone-Related Health Benefits of Methane Emission Controls." Environ Resource Econ (2015).
[1149] Shindell, Drew T. "The social cost of atmospheric release." Climatic Change (2015): 130:313–326
[1150] RIA 3-13.
[1151] RIA, 3-1.

health and welfare associated with exposure to ozone, $PM_{2.5}$, and HAP."[1152] This statement appears to underplay the level of scientific certainty that reductions in these pollutants result in improved air quality that in turn improves the health of affected communities.

The calculated net benefits of the proposed rule are summarized in Tables 5-2, 5-3, and 5-4.[1153] As addressed *supra* in Section VI.A, and as noted in the proposal,[1154] the inclusion in the regulatory impact analysis of the IWG SC-CH4 does not account for non-climate health impacts. Non-monetized health benefits in Table 5-2 include "[c]limate and ozone health benefits from reducing methane emissions"; "$PM_{2.5}$ and ozone health benefits from reducing VOC emissions"; and "HAP benefits from reducing HAP emissions[.]"[1155] For these benefits, the only numerical values are the reduced emissions in short tons for four different proposed regulatory options.[1156] EPA should seek to connect the reduced emissions of methane, VOCs, and HAPs to actual health outcomes. Some measure of the anticipated improvement in public health outcomes should be included, even if that figure represents the lower bound of the estimates or the minimum anticipated benefit. Including such a figure would allow for a better comparison of the costs and benefits of the four regulatory options.

Table 3-1 lists the currently unquantified health benefits of the proposal's projected emissions reductions, including various measurable health outcomes.[1157] According to this table, the proposal would reduce premature mortality from short-term and long-term exposure to ozone and $PM_{2.5}$, infant mortality, hospital admissions and emergency department visits, heart attacks, strokes, asthma onset and symptoms, allergic symptoms, minor restricted-activity days, school absence days, decreased outdoor worker productivity days, and morbidity from exposure to HAPs.[1158] Joint Environmental Commenters appreciate EPA's tabulation of the beneficial health outcomes of reducing methane, VOC, and HAP emissions, and urge the agency to quantify, to the greatest extent possible, the known health impacts of these emissions and the benefits of reducing these emissions.

Quantifying and monetizing the proposal's health benefits would also help to strengthen EPA's environmental justice analysis in Section 4.2.[1159] In the absence of quantified and monetized data on health impacts, this analysis currently fails to capture the full panoply of benefits that the proposal would afford if finalized. EPA concludes its summary of the proposal's environmental justice impacts as follows:

> While a definitive assessment of the impacts of this proposed rule on minority populations, low-income populations, and/or Indigenous peoples was not performed, the EPA *believes* that this action will achieve *substantial* methane, VOC, and HAP emissions reductions and will further improve environmental

[1152] 86 Fed. Reg. 63,110, 63,259 (emphasis added).
[1153] RIA, 5-3–5-8.
[1154] *Id.*
[1155] Other non-monetized benefits listed are "visibility benefits" and "reduced vegetation effects." *Id.* at 5-4.
[1156] *Id.* at 5-3–5-8.
[1157] *Id.* at 3-2–3-4.
[1158] *Id.*
[1159] RIA, 4-9–4-43.

> justice community health and welfare. The EPA believes that any potential environmental justice populations that may experience disproportionate impacts in the baseline *may realize disproportionate improvements* in air quality resulting from emissions reductions.[1160]

By quantifying and monetizing the local and regional benefits of reduced methane, VOC, and HAP emissions, EPA would be able to perform a more robust assessment of the proposal's environmental justice impacts.

EPA includes an "illustrative screening analysis" in which it monetizes VOC-related ozone health benefits.[1161] We likewise urge EPA to perform analogous supplemental analyses that monetize HAP-related health benefits, as well as all other benefits that are currently unmonetized. Particularly if EPA intends to keep these analyses as supplemental and outside the overall benefits calculation, we urge the agency to present the results even if they are associated with higher levels of uncertainty.

Although completing additional similar supplemental analyses would strengthen EPA's assessment of the proposal's health benefits, EPA should also reconsider its decision to leave the non-climate health benefits unmonetized in its overall benefit calculations. EPA does not adequately explain why it cannot incorporate this analysis in some fashion into the proposal's monetized benefits. The RIA's discussion of the illustrative screening acknowledges the uncertainties associated with that approach. However, given that EPA found the state of the science certain enough to perform this analysis, it should consider more broadly incorporating these benefit estimates into the overall benefits summary or explain why it has chosen not to do so. EPA has arrived at the estimates in Appendix B; given those estimates, EPA should be able to draw credible and conservative quantitative conclusions about the proposal's minimum non-climate health benefits. In other words, EPA can conclude that the proposed rule will have *at least* a certain dollar benefit in terms of health benefits derived from reductions in VOC emissions and corresponding estimated reductions in premature mortality and illnesses, such as those in Table B-3. EPA should add those estimates to the tables summarizing the proposal's benefits.

Additionally, the current state of the data and available modeling methods supports quantifying and monetizing the proposal's health benefits. There is a body of peer-reviewed studies that quantify reduced mortality and morbidity and/or monetize health benefits of various emission-reduction scenarios in the United States, including some that have used the community edition of EPA's Environmental Benefits Mapping and Analysis Program (BenMAP-CE).[1162] EPA should use the available modeling methods to the greatest extent feasible.

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[1160] *Id.* at 4-43.

[1161] RIA, app. B, at 1.

[1162] *See, e.g.*, Yang, Peilin et al., (2019) "Health Impacts and Cost-Benefit Analyses of Surface $O_3$ and $PM_{2.5}$ Over the U.S. Under Future Climate and Emission Scenarios," *Environmental Research*, 178, 108687, *available at* https://doi.org/10.1016/j.envres.2019.108687; Sun, Jian, et al., (2015), "Estimation of Future $PM_{2.5}$- and Ozone-Related Mortality Over the Continental United States in a Changing Climate: An Application of High-Resolution Dynamical Downscaling Technique," *Journal of the Air & Waste Management Association*, 65, 5, 611–23, *available at* https://www.tandfonline.com/doi/full/10.1080/10962247.2015.1033068; Fann, Neal, et al., (2015), "The

In sum, the final rule should emphasize the many health benefits of reducing methane, VOC, and HAP emissions. In showcasing these benefits, EPA should—to the fullest extent possible—quantify and monetize them. At the very least, if these health benefits are left unmonetized, EPA must emphasize that it has left a large proportion of the proposed rule's benefits unmonetized and, consequently, that the true gap between the benefits and costs is actually much larger than the monetized summaries reflect.

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Geographic Distribution and Economic Value of Climate Change-Related Ozone Health Impacts in the United States in 2030," *Journal of the Air & Waste Management Association*, 65, 5, 570–80, *available at* https://www.tandfonline.com/doi/full/10.1080/10962247.2014.996270; West, J. Jason, et al., (2013), "Co-benefits of Mitigating Global Greenhouse Gas Emissions for Future Air Quality and Human Health," *Nature Climate Change*, 3, 885–89, *available at* https://www.nature.com/articles/nclimate2009.

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## Table of Attachments

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| C | Memo from MJB to EDF 2018 |
| D | NSPS OOOOa Compliance Reports |
| E | EPA OGI Cost Analysis – well sites |
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