UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

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** *Via regulations.gov* *February 13, 2023*

We submit these comments on behalf of Environmental Defense Fund (EDF), Clean Air Task Force, Change the Chamber, Clean Air Council, Clean Water Action, Center for Biological Diversity, Dakota Resource Council, Earthjustice, Earthworks, Environmental Integrity Project, Environmental Law & Policy Center, Evangelical Environmental Network, Ft. Berthold Protectors of Water and Earth Rights, Food and Water Watch, Institute for Governance & Sustainable Development, Natural Resources Defense Council, National Parks Conservation Association, Pennsylvania Environmental Council, Rio Grande International Study Center, Sierra Club, Southern Environmental Law Center, Waterkeeper Alliance, and Western Environmental Law Center (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 supplemental proposal 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) supplemental proposal to update, strengthen, and expand the standards proposed in November 15, 2021 to reduce emissions of greenhouse gases and other harmful air pollutants from the Crude Oil and Natural Gas source category under the Clean Air Act.[1] As we did last year in our comments on the November 2021 proposal, Joint Environmental Commenters share an interest in addressing the climate crisis through reductions in greenhouse gas emissions from the oil and gas sector, while at the same time mitigating other harmful emissions from this sector. We again appreciate the opportunity to comment on much needed revisions to New Source Performance Standards (NSPS) for the sector and proposed Emission Guidelines (EG) for existing sources that are long overdue. Our comments highlight portions of EPA's supplemental proposal that represent important changes we support, while detailing other areas where we urge EPA to strengthen its proposal to ensure adequate protection of climate and public health.

Our comments below address the changes that have occurred in the year that passed between our submission on the November 2021 proposal and today. After a brief background that updates the scientific understanding of our current climate crisis and the role that methane, and its reductions, play, our comments are divided into three sections:

- An overview of the EPA's legal authority to address methane and VOC emissions from the oil and natural gas sector and comments on the agency's proposed regulations to address the existing source state implementation process.
- Source-specific comments addressing proposed updates to the following: fugitive emissions monitoring, including the alternative technology pathway and the Super Emitter Response Program and equipment and infrastructure sources including pneumatic controllers, pneumatic pumps, compressors, storage vessels, liquids unloading, equipment leaks at gas processing plants, associated gas at oil wells, well completions; and combustion control devices.
- Comments on how EPA should make the equivalency determination required by the newly enacted section 136 of the Clean Air Act.

The urgency of the climate crisis, methane's contribution to that crisis, and the role methane mitigation plays in solving it have all come more sharply into focus in the last year. Human-

[1] Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, 87 Fed. Reg. 74702 (proposed Dec. 6, 2022). Joint Environmental Commenters incorporate by reference our comments submitted to this docket addressing EPA's proposal in November 2021. Env't Def. Fund et al., Comment Letter on Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, Dkt. No. EPA-HQ-OAR-2021-0317-0844 (Jan. 31, 2022) [hereinafter 2022 Joint Environmental Comments]. As then, 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 document that were not previously cited in our 2022 Comments have separately been sent to the EPA Docket Center for inclusion in Docket ID No. EPA-HQ-OAR-2021-0317. Attachments A-Z to this comment are being uploaded with this comment to Docket ID No. EPA-HQ-OAR-2021-0317.

induced climate change continues to subject more and more people in all regions to devastating and deadly heat waves, and every ton of methane and other greenhouse gases that are emitted will further cement these impacts for generations to come. The toll on people is not just physical. Mental health of those in affected regions has been, and will continue to be, adversely affected. Limiting the warming of our planet to 1.5 degrees Celsius would substantially reduce the harms associated with climate change that will occur compared to warmer scenarios. To get there, however, much more progress must be made than what current actions will accomplish.

Due to the short-lived nature of methane in the atmosphere relative to carbon dioxide, and its relatively high radiative forcing power, reductions in methane can effectively reduce the peak of global warming we experience. But that depends on depth and timeliness of those reductions, and recent trends show that atmospheric methane levels have recently been at their highest-ever recorded levels. The time is now to act on methane.

The oil and natural gas sector is the largest industrial emitter of methane in the United States and presents one of the most cost-effective opportunities to achieve greenhouse gas– and methane – reductions. In addition to reducing methane, these actions will likewise reduce harmful pollution, including volatile organic compounds and hazardous air pollutants like benzene.

EPA's authority under the Clean Air Act to establish source-based technology requirements for individual pieces of equipment, and thus achieve these reductions, is clear. EPA's authority and obligation to regulate methane from this source category have only been bolstered by Congress through the passage of two items: the Congressional Review Act resolution on June 30, 2021, to Disapprove EPA's Oil and Gas Policy Rule[2] and the passage of the Inflation Reduction Act, including the Methane Emissions Reduction Program (MERP), on August 16, 2022.[3]

Our source-specific comments on EPA's supplemental proposal strongly support certain standards that EPA has updated or maintained and again highlight areas where we urge EPA to do more to adequately protect health and the environment. Each of those sources is summarized below:

- **Fugitive Monitoring:** We support EPA's equipment-based approach and recommend that EPA add separators to the list of failure-prone equipment so that any site with a separator is subject to quarterly optical gas imaging (OGI). We also urge EPA to ensure full and coextensive coverage across the leak detection and

[2] 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," Pub. L. No. 117–23, 135 Stat. 295 (2021); *See also* Env't Protection Agency, *Congressional Review Act Resolution to Disapprove EPA's 2020 Oil and Gas Policy Rule, Questions and Answers* (Jun. 30, 2021), https://www.epa.gov/system/files/documents/2021-07/qa_cra_for_2020_oil_and_gas_policy_rule.6.30.2021.pdf.

[3] *See generally* 42 U.S.C. § 7436. While MERP establishes a number of incentives for operators to reduce methane emissions, Joint Environmental Commenters note that the source-specific standards discussed below are reasonably cost-effective independent of the MERP incentives. EPA should focus the implementation of MERP on achieving reductions of methane beyond those that will be achieved by the standards and guidelines that are finalized. *See* Comments of Clean Air Task Force et al., *Comments In Response to Request for Information – Methane Emissions Reduction Program*, (Doc. ID No. EPA-HQ-OAR-2022-0875-0031) (Jan. 18 2023), https://www.regulations.gov/comment/EPA-HQ-OAR-2022-0875-0031.

repair program (LDAR) and the alternative monitoring program by requiring regular ground-based inspections at all sites, shortening and aligning repair timelines and requirements, and ensuring all components and equipment at sites are monitored during each survey. We further support EPA's frequency and detection threshold matrices, derived through rigorous modeling based on the best available data, which we believe will ensure equal or greater pollution reductions.

- **Super-Emitter Response Program:** We strongly support EPA's proposal to utilize accurate and scientifically-rigorous methane monitoring data collected by independent third parties to further drive down emissions from the largest and most egregious events. We urge EPA to ensure participation in this program is accessible and that all data and response actions are made publicly available in real time.
- **Pneumatics:** We support EPA's zero-emission requirement for controllers and pumps. We urge EPA to align its pump standards more closely with its proposed controller standard by including routed pumps as a compliance option and eliminating the tiered exemption for sites without electricity.
- **Associated Gas at Oil Wells:** We support improvements to EPA's standards for associated gas at oil wells, but encourage EPA to strengthen protections by requiring capture of associated gas using one of several abatement methods with limited exemptions for temporary flaring during certain maintenance activities or for safety reasons.
- **Combustion Control Devices:** We support the improvements to combustion control device requirements, and encourage EPA to eliminate exemptions.
- **Well Completions:** We support EPA's efforts to reduce venting and flaring from well completions, and encourage EPA to strengthen standards by prohibiting venting during the initial flowback stage and removing the technical infeasibility exception for the separation flowback stage.
- **Storage Vessels:** We continue to support the changes proposed in 2021, and we continue to urge EPA to lower the applicability threshold for storage vessels. We support EPA's new definition of "reconstruction" in the context of the storage vessel affected facility. Finally, we also support EPA's proposal to require alarms on thief hatches.
- **Compressors**: We urge EPA to lower the emissions threshold for rod packing replacement based on annual monitoring and to consider measures to reduce the significant emissions from compressor exhaust.
- **Liquids Unloading**: We support EPA's proposal to regulate liquids unloading, and specifically to require that liquids unloading be performed with zero methane or VOC emissions.

In addition to our support for many of EPA's proposed standards, Joint Environmental Commenters also support EPA's proposed update to the social cost of greenhouse gas estimates.[4]

[4] This comment does not address the proposed estimates in detail. Joint Environmental Commenters incorporate by reference the Institute for Policy Integrity's "Comments on the EPA External Review Draft of Report on the Social Cost of Greenhouse Gases (Docket No. EPA-HQ-OAR-2021-0317)," of which we are a signatory. Inst. for Pol'y Integrity, Comment Letter on the EPA External Review Draft Report on the Social Cost of Greenhouse Gases, Dkt. No. EPA-HQ-OAR-2021-0317 (Feb. 13, 2023),

Joint Environmental Commenters again appreciate the opportunity to comment on EPA's supplemental proposal. We also deeply appreciate the work that has been put into this rulemaking and hereby submit our comments to support the maximum methane reductions possible from this sector consistent with EPA's clear legal authority.

II. Background

Climate change is an existential threat to humanity. Scientific evidence overwhelmingly demonstrates that climate change is already causing immediate, devastating impacts on communities, and that these harms will worsen dramatically as greenhouse gas pollution continues to rise. We provide the below additional context and evidence in addition to that already submitted by Joint Environmental Commenters in our previous comments on the proposed rule.

The urgency for meaningful action to reduce greenhouse gas emissions remains much the same as described last year in our comments on the initial proposal. The climate crisis continues to cause widespread harm in the United States and worldwide that will worsen as greenhouse gas pollution continues to rise. The IPCC Assessment Reports, U.S. National Climate Assessments, and tens of thousands of studies make clear that human-induced climate change is a "code red for humanity," and that every additional ton of GHGs emitted into the atmosphere and fraction of a degree of temperature rise matters.[5]

Since the comment period ended for the November 2021 Proposal, the contribution of Working Group II to the Sixth Assessment Report (AR6) determined with "*very high confidence*" that "climate change has adversely affected physical health of people globally and mental health of people in the assessed regions"[6] and [i]n all regions extreme heat events have resulted in human mortality and morbidity."[7] Working Group II also said that "[n]ear-term actions that limit global warming to close to 1.5 degrees Celsius would substantially reduce projected losses and damages related to climate change in human systems and ecosystems, compared to higher warming levels."[8]

A subsequent contribution, Working Group III, further found that "[g]lobal GHG emissions in 2030 associated with the implementation of Nationally Determined Contributions (NDCs) announced prior to COP would make it *likely* that warming will exceed 1.5 degrees Celsius

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https://policyintegrity.org/documents/Joint_Comments_on_EPA_Draft_Update_to_the_Social_Cost_of_Greenhouse_Gases.pdf.

[5] United Nations, *Secretary-General's statement on the IPCC Working Group 1 Report on the Physical Science Basis of the Sixth Assessment,* https://www.un.org/sg/en/content/secretary-generals-statement-the-ipcc-working-group-1-report-the-physical-science-basis-of-the-sixth-assessment (last visited Feb. 13, 2023); Masson-Delmotte et al., Intergovernmental Panel on Climate Change, Summary for Policymakers in *Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* at 16–18, 28 (2021).

[6] Masson-Delmotte et al., Intergovernmental Panel on Climate Change, Summary for Policymakers *in Climate Change 2022: Impacts, Adaptation, and Vulnerability: Contribution of Working Group II to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* at 11, B.1.4.

[7] *Id.*

[8] *Id.* at 13, B.3.

during the 21st century."[9] Working Group III determined with "*high confidence*" that actions implemented by end of 2020 present an even more dire picture: "[p]olicies implemented by the end of 2020 are projected to result in higher global GHG emissions than those implied by NDCs."[10]

The understanding of the importance of reductions of methane pollution continues to grow, highlighting the role that such reductions play in attempting to avert the climate crisis. Working Group III found with "*high confidence*" that "[d]ue to the short lifetime of [methane] in the atmosphere, projected deep reduction of [methane] emissions up until the time of net zero [carbon dioxide] in modeled mitigation pathways effectively reduces peak global warming."[11] Yet since 2007, atmospheric methane levels have been increasing at an accelerating pace, with the largest yearly rise in methane levels ever recorded occurring in 2020 and 2021 (15 and 18 ppb respectively).[12] A deep near-term reduction in methane pollution is therefore one of the most important actions to be taken in addressing the climate crisis. The United States is the world's largest oil- and gas- producing country, and because the oil-and-gas industry is the largest industrial source of methane in the country, EPA's methane standards for this sector represent an important step toward staving off the worst impacts of climate change.

III. Legal Authority

A. The OOOOb and c Proposals Are Consistent with EPA's Section 111 Authority.

As it did with the OOOO and OOOOa rules, EPA is issuing the proposed OOOOb and c rules under section 111 of the Clean Air Act. In our comments on the 2021 proposal, Joint Environmental Commenters provided an in-depth discussion of EPA's legal authority—and its obligation—under section 111 to promulgate robust and protective standards for methane and VOC emissions from new oil and gas sources, and for methane emissions from existing oil and gas sources.[13] We also discussed EPA's history of regulating the oil and gas sector,[14] the impact of the Congressional Review Act (CRA) legislation repealing EPA's methane policy rule from 2020,[15] and how that rule was arbitrary and capricious even in the absence of the CRA legislation.[16] Because these topics are thoroughly covered in our earlier comments, we will not address them again here, but instead incorporate those comments by reference.

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[9] Masson-Delmotte et al., Intergovernmental Panel on Climate Change, Summary for Policymakers *in Climate Change 2022: Mitigation of Climate Change: Contribution of Working Group III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* at 14, B.6.
[10] *Id.*
[11] *Id.* at 24, C.2.3.
[12] World Meteorological Organization, *More bad news for the planet: greenhouse gas levels hit new highs*, Press Release Number: 26102022 (Oct. 26, 2022), https://public.wmo.int/en/media/press-release/more-bad-news-planet-greenhouse-gas-levels-hit-new-highs#:~:text=Since%202007%2C%20globally%2Daveraged%20atmospheric,systematic%20record%20began%20in%201983.
[13] 2022 Joint Environmental Comments, *supra* note 1, at 34–48.
[14] *Id.* at 39–44.
[15] *Id.* at 48–49.
[16] *Id.* at 49–58.

We do, however, wish to address the impact of the Supreme Court's June 2022 decision in *West Virginia v. EPA*.[17] In that case, the Court considered EPA's authority under section 111(d) to establish CO_2 emission guidelines for existing fossil fuel-fired power plants. Specifically, the Court held that in designating the "best system of emission reduction" for such sources, EPA lacked authority to include emission reduction measures based on generating-shifting—that is, measures reflecting the opportunity for grid-level shifts away from existing fossil-fired electricity generation like coal and gas plants and toward new renewable energy like wind and solar generators.[18] According to the Court, a generation-shifting approach for the electric power sector entailed a "transformative expansion" of its section 111(d) authority[19] and effected a "'fundamental revision of the statute.'"[20] Thus, under the "major questions doctrine," a section 111(d) rule based on generation-shifting required explicit authorization in the Clean Air Act, which the Court found lacking.[21]

The OOOOb and c proposals are fully consistent with the Court's decision in *West Virginia*. In reaching its decision, the court contrasted generation-shifting—which reduces the emissions of the "*overall power system*" by requiring dirtier sources to operate less often in favor of cleaner, non-regulated sources—with traditional "technology-based" section 111 standards, which focus "on improving the emissions performance of individual sources."[22] EPA's proposed OOOOb and c rules fall squarely within the latter category: they achieve pollution reductions entirely through the use of source-based technologies that improve the emissions performance of individual pieces of equipment. Furthermore, the Court in *West Virginia* deployed an interpretive principle—the major questions doctrine—that is reserved for "extraordinary cases " involving agency actions that, among other unusual characteristics, reflect a "transformative expansion [of the agency's] regulatory authority" and that are purported to have "vast economic and political significance" for the country.[23] On the contrary, the OOOOb and c rules reflect the use of readily available technology options that many oil and gas operators already use and support, will allow companies to defray costs and even earn profits in some instances through sale of captured gas, and will have an effectively negligible impact on consumer energy spending. In short, this is exactly the kind of "ordinary" regulation that simply does not implicate the concerns at issue in *West Virginia*.[24]

If anything, *West Virginia*'s holding confirms EPA's regulatory authority in one important respect. In particular, the state of North Dakota previously argued that EPA's role under section 111(d) was merely an advisory one, and that states, not EPA, were primarily responsible for determining the substantive emission reduction requirements to be achieved by existing sources.[25] Joint Environmental Commenters rebutted this position in our comments on the 2021

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[17] *West Virginia v. EPA*, 142 S. Ct. 2587 (2022).
[18] *Id.*
[19] *Id.* at 2610.
[20] *Id.* at 2612.
[21] *Id.* at 2614–16.
[22] *Id.* at 2611.
[23] *Id.* at 2608, 2610, 2605.
[24] *Id.* at 2608.
[25] State of North Dakota, *Comments on Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review*, 7–10 (Jan. 31, 2022) (Doc. ID No. EPA-HQ-OAR-2021-0317-0797), https://downloads.regulations.gov/EPA-HQ-OAR-2021-0317-0797/attachment_1.pdf.

proposal,[26] and the Supreme Court definitively foreclosed it in *West Virginia*. Even while it ruled against EPA's chosen system in that case, the Court explained that "[a]lthough the States set the actual rules governing existing [sources], EPA itself still retains the primary regulatory role in Section 111(d)" and "[t]he Agency, not the States, decides the amount of pollution reduction that must ultimately be achieved."[27] Accordingly, state plans under section 111(d) are "*not to exceed the permissible level of pollution established by EPA*."[28] With the OOOOc rule, the agency is thus acting firmly within the scope of its authority by issuing emission guidelines for oil and gas methane emissions that establish binding emission reduction requirements to which state plans must adhere.

B. <u>The Inflation Reduction Act – Including the Methane Emissions Reduction Program – Reinforces EPA's Regulatory Authority.</u>

Congress's passage of the Inflation Reduction Act ("IRA") – including provisions like the Methane Emissions Reduction Program – further cements EPA's authority to regulate methane. The IRA adds seven new sections to Title I of the Clean Air Act (§§132 to 138), including provisions that provide authority and resources for EPA to incentivize the deployment of zero-emission heavy-duty vehicles and zero-emission port equipment, encourage the creation of green banks, reduce emissions in the power sector, reduce methane emissions from the oil and gas sector, and support the development and implementation of climate pollution reduction plans and grants. These new provisions provide over $41 billion in resources to EPA.[29]

Critically, these provisions also affirm that reducing greenhouse gases is a "core goal" of the Clean Air Act, further entrenching EPA's authority in this regard.[30] Section 132 gives EPA $1 billion for the development of zero-emissions vehicle programs and defines "zero-emission vehicle" as "a vehicle that has a drivetrain that produces, under any possible operational mode or condition, zero exhaust emissions" of any criteria air pollutant or greenhouse gas.[31] Section 133 gives EPA $3 billion to award rebates and grants to reduce greenhouse gasses and other air pollutant emissions at ports.[32] Section 134 creates the EPA-led Greenhouse Gas Reduction Fund, intended to establish the foundation for a national green bank program to support the rapid deployment of clean energy technologies.[33] Section 135 appropriates funds to EPA for a Low Emissions Electricity Program with a focus on decreasing greenhouse gas emissions.[34] Section 137 appropriates $5 billion to EPA to award grants for greenhouse gas air pollution plans and grants.[35] And section 136 provides EPA over $1 billion to mitigate methane emissions and

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[26] *See* 2022 Joint Environmental Comments, *supra* note 1, at 211–14.
[27] *West Virginia*, 142 S. Ct. at 2601–02.
[28] *Id.* at 2602 (emphasis added).
[29] Congressional Budget Office, Cost Estimate: *Estimated Budgetary Effects of Public Law 117-169, to Provide for Reconciliation Pursuant to Title II of S. Con. Res. 14*, Table 6 at 32 (2022).
[30] Greg Dotson and Dustin J. Maghamfar, *The Clean Air Act Amendments of 2022: Clean Air, Climate Change, and the Inflation Reduction Act*, 53 Env't L. Rep. 10017, 10018(2023), https://www.eli.org/sites/default/files/files-pdf/53.10017.pdf; EDF, *The Inflation Reduction Act Includes Historic Modernization of the Clean Air Act for the American People* (Aug. 15, 2022), https://aboutblaw.com/4x0.
[31] Inflation Reduction Act, Pub. L. No. 117-169, § 60101, 136 Stat. 1818, 2064 (2022).
[32] *Id.* § 60102.
[33] *Id.* § 60103.
[34] *Id.* § 60107.
[35] *Id.* § 60114.

directs EPA to reduce emissions through a methane waste charge.[36] By amending the Clean Air Act to codify programs, appropriations, authorities, and mandates that reduce greenhouse gases, Congress confirmed EPA's authority to regulate greenhouse gas emissions.

Reiterating this same point are the direct statutory definitions now amended into the Act. The amendments repeatedly enumerate five principal climate-destabilizing gasses to define greenhouse gases under the Act, providing more than a dozen times that:

> the term 'greenhouse gas' means the air pollutants carbon dioxide, hydrofluorocarbons, methane, nitrous oxide, perfluorocarbons, and sulfur hexafluoride.[37]

These provisions confirm what the Supreme Court ruled in *Massachusetts v. EPA,* 549 U.S. 497 (2007): that greenhouse gases are "air pollutants" under the Clean Air Act and expressly affirms EPA's authority to regulate them.

EPA's authority and obligation to address methane pollution from oil and gas sources under section 111 is expressly affirmed through section 136(f)(6) in the Methane Emissions Reduction Program, which references EPA's proposed regulations.[38] Specifically, section 136(f)(6) provides for a potential exemption from the waste emissions charge under section 136(c) for "compliance with methane emissions requirements pursuant to subsections (b) and (d) of section 111[.]" For this exemption to be available, EPA must make a determination that

> (i) methane emissions standards and plans pursuant to subsections (b) and (d) of section 111 have been approved and are in effect in all States with respect to the applicable facilities; and
>
> (ii) compliance with the requirements described in clause (i) will result in equivalent or greater emissions reductions as would be achieved by the proposed rule of the Administrator entitled 'Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review' (86 Fed. Reg. 63110 (November 15, 2021)), if such rule had been finalized and implemented.[39]

In creating this exemption, Congress recognized and affirmed its support for EPA's ongoing regulatory efforts to address methane under section 111. This exemption shows that Congress was aware of EPA's November 2021 proposal and sought only to provide an exemption for the waste emissions charge if the final EPA regulations would reduce emissions at least as much as that proposal.

[36] *Id.* § 60113.
[37] *See, e.g.*, 42 U.S.C §§ 7432 (d)(4); 7433(d)(2); 7434 (C)(2); 7435(c); 7436(d); 7437(d)(2); 7438(d).
[38] 42 U.S.C. § 7436(f)(6).
[39] *Id.*

C. Legal Considerations Regarding EPA's Proposed OOOOc Emission Guidelines for Existing Sources.

1. Timing provisions

EPA's supplemental proposal grants states 18 months from the date of the final rule's publication to submit state plans under OOOOc to EPA.[40] It also requires that state plans ensure final compliance by affected sources as expeditiously as possible, but no later than 36 months after state plan submission deadlines.[41] State plans would be required to include increments of progress for affected facilities, including final control plans and final compliance certifications for owners and operators.[42] Furthermore, EPA recently proposed a set of revisions to its section 111(d) implementing regulations that would grant EPA two months after state plan submittals to make a completeness determination for each application, 12 months thereafter to evaluate and either approve or disapprove the plan, and 12 months after rejecting a state plan to promulgate a federal plan in its stead.[43] These timelines would, if finalized, apply to OOOOc.

With the exception of the time for states to submit plans for existing sources, Joint Environmental Commenters consider these timelines generally reasonable,[44] and certainly far superior to those provided in EPA's 2019 rule under 40 C.F.R. 60 Subpart Ba, which amended the previously existing section 111(d) implementing regulations.[45] As written, Subpart Ba granted states 3 years to submit plans.[46] It then granted EPA 6 months to determine whether applications were complete, 12 months to evaluate the plans, and 24 months to issue a federal plan after rejecting a state plan.[47] Subpart Ba also required state plans to include increments of progress if the date for final compliance extended beyond 24 months after state plan submission deadlines (in contrast to 16 months under the currently proposed amendments).[48] In *American Lung Association v. EPA*, the D.C. Circuit rejected the 2019 rule's timelines as arbitrary and capricious, as the agency did not address the health and environmental impacts that would have resulted from a schedule of this length.[49] The court thus vacated those provisions, and the Supreme Court declined to review this particular issue in *West Virginia*, even while it overturned other aspects of the D.C. Circuit's holding.

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[40] 87 Fed. Reg. at 74831.
[41] *Id.* at 74836.
[42] *Id*. at 74836–37.
[43] Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d), 87 Fed. Reg. 79176, 79182 (Dec. 23, 2022).
[44] Many of the signatories to this document also plan to submit more detailed comments to EPA in response to the agency's proposed amendments to the section 111(d) implementing regulations. While these organizations generally support the default timelines included in the proposed amendments, they will also provide recommendations to improve them. Among other things, they will specifically seek accelerated FIP actions where (for instance) a state indicates that it is not going to submit a plan or it becomes evident that a SIP submission is not satisfactory early on in the review process.
[45] Revisions to Emission Guidelines Implementing Regulations, 84 Fed. Reg. 32520, 32564 (Jul. 9, 2019).
[46] *Id.* at 32565.
[47] *Id.*
[48] *Compare id.*, *with* 87 Fed. Reg. at 79182.
[49] *American Lung Ass'n v. EPA*, 985 F.3d 914, 992 (D.C. Cir. 2021) (rev'd on other grounds sub nom *West Virginia v. EPA*, 142 S. Ct. 2587 (2022)).

We do, however, believe EPA should consider requiring swifter action to curtail methane emissions from existing oil and gas sources. EPA's proposed amendments to the section 111(d) implementing regulations grant states 15 months, as a general matter, to submit state plans.[50] EPA has authority to supersede the general 111(d) implementing regulations in the context of individual rulemakings, though, and asserts in the supplemental proposal that 18 months are needed for the oil and gas sector due to "variability from state to state [in] . . . . administrative process[es] (e.g., through legislative processes, regulation, or permits) that establish[] standards of performance."[51] According to the agency, an 18-month timeline "should adequately accommodate the differences in state processes necessary for the development of a state plan that meets applicable requirements."[52]

However, we urge EPA to retain the 15 months provided in the general provisions for plan submittals under the OOOOc rules as well. In the preamble to the proposed implementing regulations, EPA cites exactly this same factor noted above in establishing a default 15-month deadline, stating that "[c]onsidering this variability, 15 months should adequately accommodate the differences in state processes necessary for the development of a state plan that meets applicable requirements."[53] The agency offers no evidence in either rulemaking to suggest that state-level administrative processes are different for oil and gas sources than for any other source category, and so offers no reason why 18 rather than 15 months are necessary to accommodate state plan development in this category. Although the agency claims in a footnote to the 111(d) implementation proposal that a longer timeline is necessary in OOOOc "due to the size and variety of emission sources in the oil and gas sector,"[54] this justification appears nowhere in the OOOOc preamble itself and does not support an 18-month rather than 15-month submission period in any event.

Particularly given the urgent nature of climate change, the extremely brief window for achieving the emission reductions needed to avoid the worst impacts of that crisis, and the long-standing exposure of communities to conventional oil and gas pollution, EPA must ensure that its proposed OOOOc guidelines are implemented as swiftly as possible. Both our estimates of emission reductions and EPA's assume more timely implementation of OOOOc. To realize these reductions, swift implementation is necessary. Thus, we urge EPA to apply the proposed default 15-month timeline for state plan submissions under OOOOc rather than the extended 18-month period. Similarly, we encourage EPA to consider adopting a more accelerated timeframe than 12 months for state plan approval, and should instead explore whether a 9-month (or even shorter) window is feasible.

Finally, as noted above, EPA is proposing to allow up to 36 months after state plan submission deadlines before affected sources are required to achieve final compliance with emission guidelines. Yet most affected sources will be able to achieve compliance much earlier, particularly sources for which compliance does not require equipment swap-outs or other capital expenditures. For instance, operators of existing well sites and compressor stations can comply

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[50] 87 Fed. Reg. at 79182.
[51] 87 Fed. Reg. at 74832.
[52] *Id.* (emphasis added).
[53] 87 Fed. Reg. at 79183.
[54] *Id.* at 79181 n.8.

with OOOOc's leak detection and repair ("LDAR") requirements by hiring methane mitigation companies to perform the mandatory surveys, obviating the need for new equipment purchases. There is no reason that operators cannot begin complying with the rule's LDAR requirements immediately after EPA approves a state plan, and there is no justification for granting these sources an additional two-year grace period. As another example, EPA's standards for both reciprocating and centrifugal compressors include regular maintenance requirements, which operators can start implementing as soon as EPA approves a state plan.

In fact, as EPA explains in the context of remaining useful life and other factors (or RULOF, which we discuss more below), the only sources under OOOOc for which compliance may require "significant capital investment" are "oil wells with associated gas, storage vessels, pneumatic controllers, and pneumatic pumps."[55] For affected sources other than these, EPA is not permitting states to issue standards that depart from OOOOc's emission guidelines due to compliance costs associated with the source's remaining useful life.[56] By that same token, EPA should not permit states to grant up to three years after plan submission deadlines before these sources are required to comply. Instead, the agency should require owners and operators of these sources to achieve compliance within no more than six months of EPA's approval of a state plan, and should consider adopting a shorter timeline—24 to 30 months after plan submission deadlines, for example—for sources that do require capital expenditures for compliance.

Lastly, we encourage EPA to consider providing an additional pathway for states that would like accelerated submission and consideration of state plans, or, alternatively an accelerated FIP schedule for states that choose at the outset not to submit a plan. This would ensure that states have in place enforceable emission limits for existing sources as early as 2024.

2. *"Remaining useful life and other factors" (RULOF)*

As discussed above, EPA, rather than the states, is responsible for determining binding, substantive emission reduction requirements for any section 111(d) rule. To account for the fact that source categories may be broadly defined and reflect substantial internal variability, EPA's guidelines may include different emission limitations for subcategories, "distinguish[ing] among classes, types, and sizes within [a] category."[57] Since 1975, EPA's regulations have required that states must adopt standards no less stringent than the emission limitations provided in EPA's emission guideline for the relevant category or subcategory.[58]

However, as reflected in the variance provisions of section 111(d) adopted in 1977, Congress recognized that there may be rare[59] instances in which categories and subcategories fail to account for extenuating circumstances pertinent to specific affected sources. In other words, a source is so different from others in a category or subcategory that it is not rational to group it in that category or subcategory and apply the same emission standard. Accordingly, the provision

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[55] 87 Fed. Reg. at 74823.
[56] *Id.*
[57] *See, e.g.,* 42 U.S.C. § 7411(b)(2) (describing sub-categories for new sources); 40 C.F.R. § 60.22(b)(5) (allowing for sub-categories of existing sources in section 111(d) emission guidelines).
[58] *See*, *e.g.*, 40 Fed. Reg. 53340, 53347 (Nov. 17, 1975); 40 C.F.R. § 60.24(e).
[59] Indeed, EPA has long recognized that the opportunity to establish subcategories should "limit the number of cases in which" variances are appropriate. 40 Fed. Reg. 53340, 53345 (Nov. 17, 1975).

directs EPA to allow states "in applying a standard of performance to any particular source . . . to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."[60]

The "remaining useful life and other factors" (RULOF) provision thus allows states to grant source-specific variances from EPA's guideline requirements given unique, source-specific circumstances. At the same time, section 111(d) still accords EPA the "primary regulatory role" under section 111(d), and the "amount of pollution reduction" that EPA sets as the federal target in its emission guidelines "must ultimately be achieved" by state plans.[61]

The RULOF provision must not be applied in a way that allows variances to become the norm rather than the exception or to undercut the requirement that state standards must be at least as stringent as the emission limitation in the relevant EPA emission guideline. Since 1975, EPA's implementing rules have required that each variance be included in the state plan (or plan revision) and submitted to EPA for approval, and the state bears the burden of proving all the factual circumstances to justify that the criteria for a variance are met. The 1975 rules[62] – reaffirmed without significant change in 2019[63] – identify three criteria or conditions for a variance, at least one of which a state must demonstrate in order to issue a variance for a specific source, all subject to EPA oversight and approval. EPA's supplemental proposal includes provisions to clarify the availability of RULOF variances. The agency has proposed similar provisions in the parallel rulemaking discussed above to revise certain aspects of the section 111(d) implementing regulations.

By and large, Joint Environmental Commenters strongly support the supplemental proposal's RULOF provisions, which outline the application and review processes for variances, as well as the criteria required for such variances.

a. The application and review process for RULOF variances

Under the proposal, a state must identify and explain the basis for the variance request, identify all other possible systems of emission reduction for the source, and select an alternative "best system" from this list, as well as a degree of emission limitation based on that system.[64] The state must then impose an enforceable performance standard for the source that reflects the degree of emission limitation associated with the alternative best system and that otherwise complies with section 111(d)'s implementation regulations.[65]

It is critical that in the final rule, EPA establish these provisions as binding requirements (as it has done in the proposal) rather than merely presumptive suggestions (an option for which it

[60] 42 U.S.C. § 7411(d)(1).
[61] *West Virginia*, 142 S. Ct. at 2601–02.
[62] 40 C.F.R. § 60.24(f).
[63] 40 C.F.R. § 60.24a(e). The 2019 RULOF provisions were finalized in the same rulemaking as EPA's ACE rule. 84 Fed. Reg. 32520 (July 8, 2019). While the ACE rule was contested in *American Lung Association*, as were EPA's amended timeline provisions in the general section 111(d) implementing regulations, no party challenged the agency's 2019 revisions to the RULOF provisions.
[64] 87 Fed. Reg. at 74829 (to be codified at 40 C.F.R. § 60.5365c(b)-(c)) (Subsequent references to the proposed regulatory text will follow the convention, "Proposed 40 C.F.R. § ##.##").
[65] *Id.*§ 60.5365c(b), (h).

requests comment).[66] Non-binding provisions would open the door for states to grant variances for various other reasons that EPA would have to assess on a case-by-case basis. As explained below, that was exactly the problem with the 1975 and 2019 implementing regulations. The problem would be exacerbated by the large number of sources in the oil and natural gas sector; administrative necessity by itself is sufficient reason for EPA to put binding requirements on variances.

The supplemental proposal also maintains certain conditions that are essential to prevent abuse of the RULOF provision. First, it prohibits states from issuing variances merely because a source wishes to use a different system of emission reduction than the agency's designated "best system." The standard set by the state must achieve the degree of emission reduction as provided by the emissions guideline unless the conditions for variances are met. Second, the proposal requires that any operating conditions serving as the basis for a variance be included in the plan as federally enforceable requirements for the source in question. Third, with respect to age-based variances in particular, the proposal establishes a heightened standard of specificity, requiring states to demonstrate that the unit's retirement date conflicts with at least one of five factors needed to fully satisfy EPA's guidelines.[67] Together, these requirements will help prevent abuse of RULOF-based variances while still providing the regulatory flexibility that Congress contemplated in enacting section 111(d).

b. The conditions for receiving RULOF variances

The proposal places reasonable limitations on the circumstances under which variances may be granted. The 1975 and 2019 regulations stated, without elaboration, that states may establish more lenient standards for an affected source if they demonstrate at least one of three conditions:

> (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.[68]

This language gave states too much room for interpretation and does little to prevent state-based variances from being granted to sources that, in reality, exhibit no exceptional characteristics compared to the other members of their category or subcategory. Put simply, this language could allow the exception to swallow the rule. For this this reason, the additional restraints that EPA has placed in the supplemental proposal on the issuance of variances serve a critical function by helping to ensure that variances are reserved for only truly extraordinary circumstances. Below, we discuss the conditions that EPA has established and provide recommendations for further refinement and improvement of the RULOLF provisions in the supplemental proposal.

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[66] *See* 87 Fed. Reg. at 74819.
[67] Proposed 40 C.F.R. § 60.5365c(e)(1)(i)-(v).
[68] 40 C.F.R. §§ 60.24(f), 60.24a(e).

i. Condition #1: Variances based on compliance costs

We urge EPA to remove or limit "unreasonable costs of control resulting from . . . basic process design" as a basis for granting variances in the first clause.[69] *Id.* § 60.5365c(a)(1). While this term is not new to OOOOc—it also appeared in the 1975 and 2019 regulations—it is not clear what purpose it serves, or what it even means. If a source's "basic process design" requires using outdated technology that cannot incorporate the best system of emission reduction at a reasonable cost, then that is no reason to grant the source a relaxed standard, particularly since EPA's "best system" *must* reflect reasonable costs as a general matter. It does not contravene Congress's intent if certain obsolete sources end up retiring rather than incurring the costs required to install the "best system" technology, particularly where doing so would not result in stranded assets. EPA should thus limit the first category of variances to unreasonable costs based on plant age or location. Alternatively, the agency should provide clearer guidance and limitations on when states may grant variances reflecting "basic process design" considerations.

We also strongly support EPA's proposal to limit possible RULOF variances based on compliance costs resulting from a source's remaining useful life to only four subcategories of sources in the oil and gas source category: oil wells with associated gas, storage vessels, pneumatic controllers, and pneumatic pumps.[70] As the agency explains in the rule preamble, these are the only sources that must make significant capital expenditures in order to comply with the proposed OOOOc standards. EPA notes that:

> BSER based on compliance measures that do not require such upfront capital expenditures would have been demonstrated to have reasonable costs in the EPA's analysis for the presumptive standards. This would largely be the case if the affected facility operates for two years or 50 years.[71]

Accordingly, the agency is—appropriately—not permitting variances based on age-related compliance costs for affected facilities other than the four types noted above. In our submission on the 2021 proposal, Environmental Commenters explained that Congress's primary reason for enacting the RULOF provision was to avoid imposing otherwise unreasonable capital costs on an aging facility that will close before the period assumed for amortizing those costs for other members of the relevant category or subcategory.[72] This concern simply does not apply where compliance requires no significant upfront capital investment in the first place—which is true for all the OOOOc-affected sources apart from oil wells with associated gas, storage tanks, and pneumatic equipment. The supplemental rule's RULOF provisions therefore adhere to Congress's intent and ensure that sources do not receive a windfall in terms of relaxed standards merely because they are old and nearing retirement.

Another way to see the same point is this: the annualized cost-effectiveness of a measure that has no upfront capital investments is the same regardless of the remaining useful life of the source. Since EPA determined the annualized cost-effectiveness of the measure to be reasonable in

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[69] Proposed 40 C.F.R § 60.5365c(a)(1).
[70] *Id.* § 60.5365c(e)(1)(vi)(A)-(D).
[71] 87 Fed. Reg. at 74823.
[72] *See* 2022 Joint Environmental Comments, *supra* note 1, at 214–15.

setting BSER, that annualized cost-effectiveness remains reasonable for a source with a relatively short remaining useful life. In other words, the remaining useful life does not create any difference between the aging facility and EPA's BSER determination under these circumstances, let alone a "fundamental difference."[73]

Even for sources that do require capital investments for compliance, the supplemental rule appropriately establishes at least *three* other important limiting conditions before they can qualify for a variance. *First*, as EPA explains in the preamble, costs associated with a source's remaining useful life must not merely increase for a variance to be warranted, but must rise to the level of *unreasonableness*, as determined by the agency, in terms of dollars spent per ton of pollution abated.[74] This is wholly appropriate. It responds to Congress's concern about stranded assets without allowing sources to wrongly benefit from reasonable increases in control costs, and does not account for particular sources' margin of profitability, a consideration that should not be relevant to pollution control decisions. As already noted, a cost differential must be fundamental, not minor, in order to be considered unreasonable.

Second, the supplemental proposal requires sources receiving age-based variances for any reason—including reasons unrelated to cost—to demonstrate that "[t]he increased emissions for the duration of the remaining useful life will not result in negative impacts to the surrounding communities, including those most affected by and vulnerable to the health and environmental impacts of the plan."[75] This is a critically important guardrail. It appropriately balances the need for regulatory flexibility with section 111's lodestar of health and environmental protection, and it also specifically requires an evaluation of how vulnerable communities will be affected by variances. This sort of balancing fully aligns with the language of section 111(d), which does not direct that sources are necessarily entitled to age-based variances under any particular circumstances. Rather, the provision *allows* states to "*take into consideration*" remaining useful life and other factors when establishing performance standards for particular sources.[76] States must weigh these considerations against other factors—namely, health and environmental impacts—when determining whether to grant a variance.

Indeed, we encourage EPA to extend this community-protection requirement to all variance requests, regardless which clause they fall under. As currently written, the proposed RULOF provisions requires that states "consider the potential health and environmental impacts and benefits of control to any community most affected by and vulnerable to impacts from the designated facility" whenever it calculates a less stringent standard for a source, regardless of the variance category.[77] This is an improvement from the status quo, but it is less protective than the condition that applies specifically to age-based variances, which *prohibits* a state from granting a less stringent standard for any source unless it can demonstrate that the increased emissions resulting from the variance "not result in negative impacts to the surrounding communities."[78]

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[73] As discussed in greater detail below, Environmental Commenters urge that the "fundamentally different" language that EPA proposes to include under the third variance condition (i.e., the "other factors" condition) apply to all conditions for receiving a variance under Section 111(d).
[74] *See* 87 Fed. Reg. at 74822–23.
[75] Proposed 40 C.F.R. § 60.5365c(e)(1)(vii).
[76] 42 U.S.C. § 7411(d)(1) (emphasis added).
[77] Proposed 40 C.F.R. § 60.5365c(g).
[78] *Id*. § 60.5365c(e)(1)(vii).

There is no reason not to require such a showing for all types of variances. EPA should therefore include this requirement regardless of the variance clause the state is invoking when calculating a less stringent standard for any source.

Third, for any source receiving an age-based variance, the state must establish a federally enforceable retirement commitment in the plan. This will discourage unwarranted variance applications and will ensure that excess pollution resulting from variances will be of limited duration. However, EPA must improve this requirement in several regards. First, the proposal does not specify any timeframe within which a source receiving an aged-based variance must retire. The agency must clarify this to require that a source receiving a variance of this nature retire at the expiration of the amortization schedule that the source owner has used to demonstrate unreasonable compliance cost, subject to a reasonable capital recovery window and interest rate specified by EPA. Furthermore, the proposed regulations provide that "if a designated facility's retirement date is imminent, the plan may apply a standard that reflects the designated facility's business as usual."[79] EPA does not define "imminent" in this context, leaving it susceptible to an inappropriately expansive definition in state plans. The agency must establish a clear definition that limits "imminent" retirements to those that are very near—no more than one to two years.

We further urge EPA to drop the proposed "escape hatch" that would allow a source benefiting from a variance to abrogate its retirement commitment. Specifically, we recommend that EPA delete this provision: "If an owner or operator of such a designated facility elects not to retire the designated facility as scheduled, the designated facility must achieve compliance with the standard listed in the Model Rule for the designated facility by the date otherwise required for the designated facility."[80] This is inherently contradictory: a retirement date cannot be "an enforceable commitment" if a source may "elect[] not to retire" by that date. Even if the source in question must meet the unmodified standards after that point, there is no provision for making up the extra pollution allowed during the variance period. Furthermore, this provision will allow sources and states to adopt spurious retirement dates that they never intend to honor, effectively delaying compliance with the original standard.

In fact, if the "escape hatch" provision were to be used, it would undermine the equivalency determination EPA must make under the IRA, which we discuss in more detail later in these comments. In this case, the state plan at issue might fall short of achieving the emission reductions that would have resulted if the emission standards in the November 2021 proposed emission guidelines were fully implemented. Furthermore, section 111(d) plans must be subject to "similar"[81] procedures as section 110 state implementation plans. Among those procedures is an anti-backsliding provision, section 110(l), which prohibits revisions that interfere with the NAAQS or other requirements of the Act.[82] This suggests such backsliding, as in the case here of a plan that replaces a retirement with a provision that allows the source to continue to emit pollution, should not be allowed.

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[79] *Id.* § 60.5365c(e)(3).
[80] *Id.* § 60.5365c(4).
[81] 42 U.S.C. § 7411(d)(1).
[82] *Id*. § 7410(l).

ii. Condition #2: Variances based on impossibility or technical infeasibility

We also urge EPA to amend the second clause so as to remove "technological infeasibility . . . of installing necessary control equipment" as a potential basis for a variance."[83] Under the 1975 and 2019 regulation this clause was limited to situations of "physical impossibility." "Technical infeasibility" is a highly imprecise term that is susceptible to abuse and overapplication, and EPA has provided no definition or guidance on the term. There may, for example, be instances in which a source must undertake some small, additional, and cost-effective modification in order to install a control technology and on that account seek–inappropriately–a variance based on "technically infeasible."

To the extent that a source truly is uniquely situated from a technical standpoint, the third variance clause already encompasses it with the "fundamental difference" limitation that we recommend apply to all three clauses (see below). It is not clear what other bases for technological infeasibility these clauses would not already cover, particularly since EPA has also already proposed to allow the application of alternative standards at certain facilities based on technical infeasibility.[84] Accordingly, we urge EPA to remove "technical feasibility" as a basis for allowing variances, or at least to make clear that it too is subject to the requirement of fundamental difference. If the agency does retain this factor, it must provide much more specific guidance and limitations on its application.

iii. Condition #3: Limiting "other factors" to "fundamentally different factors"

Under the 1975 and 2019 RULOF provisions, the non-specific "other factors" exemption in clause (3) is vulnerable to abuse by sources seeking to avoid otherwise applicable pollution control requirements. However, the supplemental proposal now inserts important limiting factors into the "other factors" exemption process. First, the "other factors" category now reads as follows: "other factors . . . that are fundamentally different from the factors considered in the determination of the best system of emission reduction in the emission guidelines."[85] "Fundamentally different" means more than just "some difference." Rather, the source must be so different that it is not rational to expect it to achieve the same degree of emission limitation as other sources in the category or subcategory. The "fundamentally different" qualifier will prevent a state from displacing EPA's judgment regarding the emission limitation that reflects the best system of emission reduction for a category or subcategory on minor and unexplained or unproven grounds.

EPA has employed this definition of "fundamentally different" for decades in the context of the Clean Water Act. There, EPA may grant a "fundamentally different factor" variance from national effluent limitations for a specific point source.[86] But that variance is only permissible in

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[83] Proposed 40 C.F.R. § 60.5365c(a)(2).

[84] For example, EPA has proposed to allow flaring of associated gas at oil wells if it is technically infeasible to route to a sales line, use onsite, use for another beneficial use, or reinject or inject the gas. 87 Fed. Reg. at 74780.

[85] Proposed 40 C.F.R. § 60.5365c(a)(3)).

[86] *See* 40 C.F.R. pt. 125, subpart D.

abnormal circumstances, such as when imposing the national effluent limitation would result in a removal cost "wholly out of proportion" with EPA's estimated removal costs.[87] Thus, under one of the CAA's companion statutes, a "minor difference" will not justify a "fundamentally different factor" variance. There is no reason to read EPA's proposed language here any differently.

Furthermore, as noted above, we urge the agency to extend the "fundamentally different" qualifier to all three variance clauses. Any variance is appropriate only if the emission guideline EPA did not already consider the factors at play in determining the emission limitation that reflects the "best system of emission reduction" for the relevant source category or subcategory. For example, the first clause permits variances based on unreasonable costs resulting from plant location. A state should have to demonstrate that compliance cost differences for the source seeking a variance are "fundamentally" different from the costs representative of other sources in the relevant category or subcategory. Likewise, under the second clause, to invoke "physical impossibility," a state should have to demonstrate that a source's physical configuration poses an obstacle so fundamental that the emission limitation cannot be met at all, or only at fundamentally (order of magnitude) higher cost compared to other members of the relevant category or subcategory.

EPA could, though, provide greater clarity in the regulatory text regarding the nature of "fundamental differences." According to the preamble, a "fundamental difference" must relate to a particular factor that is relevant to EPA's determination of the "best system" for a category or subcategory, on the one hand, and that same factor as applied to the specific facility seeking a variance.[88] Yet the proposed rule's regulatory text does not quite capture this: it refers to "other factors specific to the facility (or class of facilities) that are fundamentally different from the factors considered in the determination of the best system of emission reduction in the emission guidelines." This text could be interpreted to allow states to grant variances based on extra-statutory factors that EPA did not and could not have considered in setting BSER, such as local political opposition to stringent regulations.

Instead, the provision should read along the following lines: "other factors considered by EPA in determining the best system of emission reductions which, when applied to the specific facility, are fundamentally different from EPA's finding for the category or sub-category." Thus, when EPA asks whether there are "other considerations" under which variances are appropriate,"[89] those considerations themselves must be relevant to the statutory factors EPA considered in determining BSER, such as cost and degree of emissions reduction, even while the application of those factors to the facility in question result in fundamental differences.

[87] 40 C.F.R. § 125.31(b)(3)(i) (emphasis added).
[88] 87 Fed. Reg. at 74819.
[89] *Id*. at 74821

c. Granting RULOF variances for source limitations that are more stringent than EPA's proposed guidelines

Finally, we support EPA's interpretation of section 111(d) as allowing EPA to approve a state plan with standards for a category, subcategory, or individual source that are *more* stringent than the emission limitations in EPA's guidelines.

Since 1975, EPA has interpreted the statute to require state plans that are "*no less stringent* than the corresponding emission guideline(s),"[90] a formulation that clearly contemplates more stringent standards. This squares with the Clean Air Act itself, which directs EPA to approve only those plans that are "satisfactory."[91] The notion that EPA could reject as somehow less than "satisfactory" a state plan that not only achieved but exceeded the emission reductions required by the agency's guidelines would contradict the logic of the Supreme Court's holding in *Union Electric Company v. EPA*.[92] There, the Court ruled that EPA may not reject a state implementation plan under section 110 of the Act on the grounds that the plan exceeds the minimum federal requirements.[93] As the Court explained, legislative history, along with the "structure and purpose" of the Act, confirm that state implementation plans must "meet the '*minimum* conditions' of the [provision]," but that "[b]eyond that, if a State makes the legislative determination that it desires a particular air quality by a certain date and that it is willing to force technology to attain it or lose a certain industry if attainment is not possible," EPA may not thereby reject the plan on the grounds that it is too stringent.[94]

As the court further explained, section 116 of the Act specifically preserves state authority to adopt standards more protective than EPA's under this provision of the statute. Thus, if EPA were permitted (or required) to reject state implementation plans as *overly* (as opposed to insufficiently) protective of health and the environment,

> [it] would not only require the Administrator to expend considerable time and energy determining whether a state plan was precisely tailored to meet the federal standards, but would simultaneously require States desiring stricter standards to enact and enforce two sets of emission standards, one federally approved plan and one stricter state plan. We find no basis in the Amendments for visiting such wasteful burdens upon the States and the Administrator, and so we reject the argument of Amici.[95]

All of these principles apply equally to section 111(d) plans as to section 110 plans. Indeed, Congress explicitly modeled section 111(d) on section 110, directing the Administrator to "establish a procedure similar to that provided by section 7410 of this title"[96] by which a state submit plans achieving the federal emission reduction requirements for sources within their

[90] 40 C.F.R. §§ 60.24(c), 60.24a(c).
[91] 42 U.S.C. § 7411(d)(2)(A).
[92] 427 U.S. 246 (1976).
[93] *Id.* at 265.
[94] *Id.* at 264–65 (emphasis added).
[95] *Id.* at 264.
[96] 42 U.S.C. § 7411(d)(1).

borders. Thus, for all the reasons described in *Union Electric*, EPA rightly concludes that it may not reject section 111(d) state plans that are more stringent than the federal emission guidelines.

IV. Source Specific Comments

In this section we provide comments, recommendations, and supporting analysis on each of EPA's proposed standards for affected and designated facilities. Our comments in this section are intended to apply to both the proposed OOOOb and OOOOc, unless specifically mentioned otherwise. Likewise, references to and comments regarding the proposed OOOOb regulatory text are intended to apply equally to the parallel section in the OOOOc regulatory text. We also incorporate by reference our comments and attachments submitted on the initial proposal. Here, however, we focus on new aspects of and analysis for the supplemental proposal.

A. Overall Emissions Reductions

We support EPA's proposed standards, which we estimate could cumulatively reduce emissions by approximately 46 million metric tons through 2035. We further estimate that final rules could achieve over 47 million metric tons of reductions through 2035 by incorporating improvements like those we describe in this section. Once fully implemented, we estimate EPA's proposed standards could cut methane emissions by about 4.5 million metric tons per year. These annual reductions underscore the importance of timely implementation, especially for existing sources. Below we present our estimated reductions for various standards.

Table 1: Estimated Emissions Reductions 2023-2035[97]

Source	Base Proposal	Strengthened*
Fugitive Emissions	15,000,000	16,000,000
Storage Vessels	1,500,000	1,700,000
Pneumatic Devices**	22,000,000	22,000,000
Liquids Unloading	420,000	420,000
Compressors	5,900,000	5,900,000
Associated Gas from Oil Wells	1,100,000	1,400,000
Well Completions	510,000	510,000
Total Reductions* **	**46,000,000**	**47,000,000**
*(lowered tank threshold for storage vessels; adding separators to equipment list at section 60.5397b/c(g)(1)(iii) for fugitive emissions; no broad exemptions allowing flaring for associated gas) **(from EPA's 2022 RIA, Table 5-5) ***(assumes 2026 implementation of OOOOc; numbers may not sum due to rounding)		

[97] Reductions are shown in metric tons of methane. These estimates assume OOOOc is implemented in 2026. For more scenarios and a description of the methodology, please *see* Methane Policy Analyzer Methodology (Attachment A).

B. Fugitive Monitoring

We support EPA's proposed fugitive monitoring requirements, which we believe will significantly reduce methane emissions from oil and gas sources. In this section, we offer additional analysis and recommendations for improvements. First, we discuss the proposed fugitive monitoring requirements at well sites and centralized production facilities, followed by a discussion of compressor stations. We believe that EPA's decision to tier monitoring requirements based on site type and the presence of equipment ensures that the sites most likely to be large emissions sources are appropriately monitored while allowing for reduced frequencies at lower-risk sites. This approach maximizes emissions reductions and cost-effectiveness. Second, we discuss the proposed alternative advanced technology option, which EPA presents in matrices of screening frequencies based on detection capabilities. In developing the matrices, EPA relied on peer-reviewed modeling using nationally representative and scientifically-backed inputs. This resulted in multiple screening options that will allow operators flexibility while ensuring emission reductions equivalent to or better than those achieved through optical gas imaging (OGI).

Based on our review and analysis of the proposed fugitive monitoring standards, we recommend that EPA:

- Ensure any site with a separator is subject to quarterly OGI monitoring (or the equivalent alternative screening option) by adding separators to the equipment list at section 60.5397b/c(g)(1)(iii);
- Ensure that all monitoring surveys comprehensively cover all potential emissions sources at sites and that leaks are mitigated within 30 days of detection (or receipt of screening results) by shortening the timeline for first attempt and final repair;
- Ensure equivalent reductions occur across diverse basins and over time under the alternative by requiring annual OGI pairings with higher detection threshold options; and
- Ensure that all sites are subject to regular ground-based inspections by extending AVO requirements to sites opting for the alternative periodic screening option.

Fugitive emissions from leaks and equipment failures are the most significant source of methane emissions from the oil and gas sector, representing over two thirds of total emissions in the production segment.[98] Readily available and low-cost technologies exist to find and fix these leaks and malfunctions. Comprehensive leak detection and repair (LDAR) standards are therefore an indispensable element of any program aiming to drive down methane emissions from oil and gas. 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."[99] Regular site visits, maintenance, and equipment upgrades can also prevent these emissions from ever occurring. Nonetheless, small and large emission events occur frequently and repeatedly across the oil and gas supply chain from all types of facilities operated by large and small companies. We

[98] 2022 Joint Environmental Comments, *supra* note 1, at 65.
[99] 87 Fed. Reg. at 63177.

anticipate that with full implementation of EPA's proposed standards, at least the largest fugitive emission events will become less common. However, given the sprawling and leaky nature of the oil and gas supply chain, it is critical that EPA adopt a comprehensive LDAR program that requires frequent inspections for leaks.

EPA should seek to reduce fugitive emissions to the greatest extent possible, with the ultimate goal of fully eliminating these preventable and unnecessary emissions. Existing and widely available technologies and practices allow for cost-effective detection of leaks that can then be repaired, leading to significant emission reductions, cost savings from captured gas, and improved health outcomes for nearby residents. Final rules should ensure fugitive emissions reductions of at least 80%, or roughly equivalent to EPA estimates of what quarterly Optical Gas Imaging (OGI) would achieve. We estimate that a comprehensive and frequent monitoring and repair regime could reduce methane emissions by over 1.5 million tons per year and urge EPA to finalize standards at least as protective as what it has proposed.

1. Leak detection & repair

In this section, we discuss the proposed LDAR standards for well sites, centralized production facilities, and compressor stations. We support the proposed standards, which will greatly–and cost-effectively–reduce emissions. Below, we describe the rationales underlying our support, provide additional analysis, and include recommendations for improvements. Our central recommendation is that EPA should add separators to the list of failure-prone equipment so that any site with a separator is subject to quarterly OGI. We also urge EPA to align OGI and AVO inspection coverage and requirements with the alternative by requiring monitoring of the full site, including control devices. EPA should also ensure that estimated reductions are achieved by requiring repairs within 30 days.

a. OGI is the best system of emission reduction

Building from extensive experience, past regulations, and the experience of leading states, EPA has appropriately proposed leak detection and repair using OGI cameras as the best system of emission reduction for addressing fugitive emissions. OGI is a proven technology that has now been deployed for detecting and mitigating fugitive emissions from oil and gas operations for well over a decade.[100] EPA and other regulators have long relied on OGI monitoring because of its proven ability to detect emissions from a wide range of equipment and its ability to precisely pinpoint emission sources that can then be prioritized for repair.[101] This technology has been

[100] *See, e.g.*, Reg'l Air Quality Council, *RAQC Announces Optical Gas Imaging Camera Loan Program* (April 23, 2012), https://raqc.org/regional_air_quality_council_announces_optical_gas_imaging_camera_loan_prog/.
[101] *See* Teledyne FLIR, *Optical Gas Imaging Regulations in the United States and Europe*, https://www.flir.com/discover/instruments/gas-detection/optical-gas-imaging-regulations-in-the-united-states-and-europe/ (last visited Feb. 11, 2023).

extensively tested and evaluated in the field,[102] and it has also been deployed and used successfully by operators for years.[103]

OGI cameras have a very low detection threshold, meaning they are sensitive and can detect small leaks that other technologies miss. As proposed, OGI cameras would be required to have a 100% detection limit of 60 grams per hour. This is far more sensitive than the technologies that may be permitted under the alternative options, which only require the ability to detect emissions ranging from 1 to 30 *kilograms* per hour. This means that when used with the same frequency and coverage, OGI will always be more effective at reducing emissions because it will detect all the same large emissions *and* the portion of smaller emissions that are below the detection threshold of less sensitive technologies. In addition, OGI can almost always immediately pinpoint the emissions source, while alternative options may require a follow up on site survey to locate the emission source before a repair can be attempted. Technologies with higher detection thresholds will always miss a certain fraction of smaller emissions and therefore cannot mitigate certain emissions that OGI can, regardless of frequency.

LDAR programs using OGI cameras are a highly effective, low cost, and proven means for reducing fugitive emissions. Numerous studies have shown that over time and with repeated inspections, OGI programs reduce emissions and also help to prevent large emission events.[104] Studies have indicated that such LDAR programs are highly effective—some finding that more than 90% of leaks remained fixed a year later.[105] The same study found that "emissions reduced by 44% across all 8 facilities between the first and second LDAR survey," similar to EPA and Environment and Climate Change Canada's assumption that an annual OGI-based LDAR survey will reduce emissions by 40%.[106] However, it also found that each individual survey reduced a site's overall fugitive emissions by only 22% on average because of new leaks that occurred afterwards, indicating that "frequent LDAR surveys might be necessary for long-term emissions management."[107]

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[102] *See, e.g.*, Daniel Zimmerle et al., *Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions*, 58 Env't Sci. Tech. 11506 (2020), https://pubs.acs.org/doi/10.1021/acs.est.0c01285; Seth N. Lyman et al., *Aerial and ground-based optical gas imaging survey of Uinta Basin oil and gas wells*, 7 Elementa: Sci. of the Anthropocene 43 (2019), https://online.ucpress.edu/elementa/article/doi/10.1525/elementa.381/112514/Aerial-and-ground-based-optical-gas-imaging-survey.

[103] Jonah Energy, for example, has used this technology since 2005 to reduce its emissions by 75%. *See* FLIR Media, *Optical Gas Imaging at Jonah Energy* (May 2016), http://www.flirmedia.com/MMC/THG/Brochures/OGI_014/OGI_014_EN.pdf; Teledyne FLIR, *Jonah Energy Reduces Fugitive Natural Gas Emissions by 75% Using FLIR OGI Camera* (Feb. 2021), https://www.flir.eu/discover/instruments/gas-detection/jonah-energy-reduces-fugitive-natural-gas-emissions-by-75-percent-using-flir-ogi-camera/.

[104] Jiayang Wang et al., *Large-Scale Controlled Experiment Demonstrates Effectiveness of Methane Leak Detection and Repair Programs at Oil and Gas Facilities*, EarthArvXiv (2021) (non-peer reviewed preprint), https://eartharxiv.org/repository/view/2935/; Arvind P. Ravikumar et al., *Repeated leak detection and repair surveys reduce methane emissions over scale of years*, 15 Env't Rsch. Letters 034029 (2020), https://iopscience.iop.org/article/10.1088/1748-9326/ab6ae1/pdf [hereinafter Ravikumar 2020].

[105] Ravikumar 2020, *supra* note 104.

[106] *Id.*

[107] *Id.*

EPA's assumptions about the effectiveness of OGI are also supported by recent data and FEAST modeling. In Colorado for example, instrument-based monitoring (typically with OGI cameras) inspections found 90% of leaks, despite constituting just 5% of total inspections in 2020.[108] This closely mirrors 2019 annual data, where 89% of leaks were found with instrument-based monitoring. Studies have produced similar results, for example finding that "over 80% of emissions can be detected [with OGI] from an imaging distance of 10 m."[109] EPA has long assumed an 80% mitigation effectiveness for quarterly OGI and has updated that number to 77% in the supplemental proposal based on FEAST modeling results.[110] This assumption is reasonable and aligns with the literature, EPA's past practice, and our own assumptions derived from FEAST.[111]

b. OGI is Cost-Effective

Here we discuss the cost of OGI and AVO monitoring and present a revised cost-effectiveness analysis demonstrating that EPA's assumptions are reasonable and conservative. Fugitive monitoring and repair with OGI cameras is low cost, with a commonly cited per-site inspection cost of $600.[112] With new regulatory requirements, company-set emission reduction targets, and rapid growth in the methane mitigation sector,[113] it is likely that OGI monitoring will become even lower cost in the coming years and prior to the initial date for existing source compliance.

In this supplemental proposal, EPA's cost assumptions remain largely unchanged from the November 2021 proposal. There, EPA examined three elements of OGI monitoring costs: (1) periodic monitoring for leaks; (2) repair of leaks identified; and (3) documentation of the detection and repair activities. 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 reductions achieved by various inspection frequencies to estimate cost-effectiveness.

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[108] Colo. Dep't Pub. Health & Env't, *2020 LDAR Annual Reports (Regulation 7 Section XVII)*, https://cdphe.colorado.gov/2020-ldar-annual-reports-regulation-7-section-xvii (last visited Feb. 11, 2023).
[109] Arvind P. Ravikumar et al., *Are Optical Gas Imaging Technologies Effective For Methane Leak Detection?*, 51 Env't Sci. Tech. 718 (2017), https://pubs.acs.org/doi/10.1021/acs.est.6b03906.
[110] U.S. Env't Protection Agency, *Regulatory Impact Analysis of the Supplemental Proposal for the Standards of Performance for New, Reconstructed, or Modified Sources and Emissions Guidelines for Existing Sources: Oil and Gas Climate Review* at 231, Table 7 (Nov. 2022) (Doc. ID No. EPA-HQ-OAR-2021-0317-1566) [hereinafter Supplemental RIA].
[111] *See* Arvind P. Kumar, FEAST: US – Alternative LDAR Programs for Representative US O&G Production Facilities (Jan. 2022) (included as Attachment L to 2022 Joint Environmental Comments, *supra* note 1).
[112] U.S. Env't Protection Agency, *EPA's Methane Detection Technology Virtual Workshop Transcript Day Two* at 24 (Aug. 24, 2021) (Doc. ID No. EPA-HQ-OAR-2021-0317-0181).
[113] *See* Marcy Lowe, Datu Rsch., *Advanced Methane Monitoring: Gauging the Ability of U.S. Service Firms to Scale Up* (July 22, 2021), http://blogs.edf.org/energyexchange/files/2021/08/Advanced-Methane-Monitoring-Survey_DatuResearch_8-10-2021.pdf.

We analyzed EPA's assumptions underlying the OGI cost estimates and cost-effectiveness analysis.[114] 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 overestimated 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 most reported travel and survey times were far shorter than EPA's assumptions. Our recommendations for strengthening EPA's cost analysis are presented fully in our comments on the initial proposal.[115]

Here, we present an updated and fully comprehensive version of our cost analysis based on our review of data from over 16,000 upstream OGI surveys included in compliance reports submitted under NSPS OOOOa.[116] We downloaded and reviewed all of the 26,724 annual compliance reports submitted to EPA from 2017 to early 2021 via the WebFIRE database. 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.

Our review of these annual compliance reports shows an average combined travel and survey time of 1.75 hours, much less than EPA's 2.5 hour assumption. We also found a median survey time of 30 minutes and an average of 60 minutes.[117] This supports and aligns with EPA's use of a 30 minute survey time in its recent cost analysis. The average is affected by a small number of surveys that took over 90 minutes, as presented in the histograms included in with the full attached analysis. The results of this analysis are presented in the Figures 1 and 2 below.[118]

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[114] 2022 Joint Environmental Comments, *supra* note 1, at 72–84.
[115] *Id.* at 74–82.
[116] For a complete description of the methodology, *see* Env't Def. Fund, OOOOa *Compliance Report Analysis Methodology* (included as Attachment B).
[117] *See* OGI Survey Time Analysis Final (included as Attachment C), for a full printout of the figures.
[118] For full compliance report analysis, *see* Env't Def. Fund, *OOOOa Compliance Report Analysis Full Workbook* (Attachment D).

Figure 1

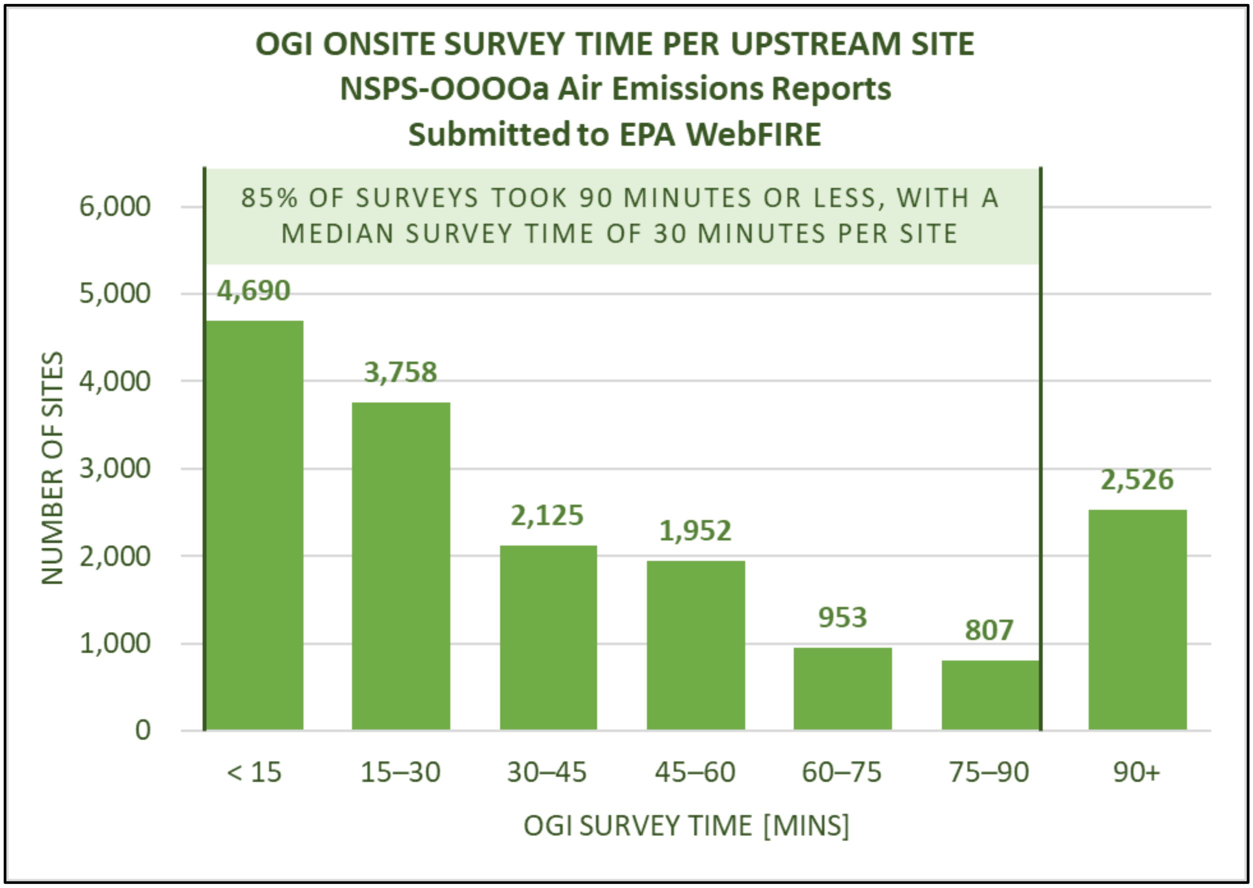

Figure 2

	OGI SURVEY TIME (MINS / SITE) – NUMBER AND PERCENTAGE OF SURVEYS									SURVEYS
	≤ 15	15–30	30–45	45–60	60–75	75–90	90+	AVERAGE	MEDIAN	
OGI SURVEY TIME PER UPSTREAM SITE	4,690	3,758	2,125	1,952	953	807	2,526	62	30	16,811
	28%	22%	13%	12%	6%	5%	15%			

≤ 90 MINS	85%
≤ 75 MINS	80%
≤ 60 MINS	75%
≤ 45 MINS	63%
≤ 30 MINS	50%
≤ 15 MINS	28%

Our analysis also examined all the available information on travel time between surveys. For the upstream LDAR surveys with reported start- and end-time data in the dataset, we looked at surveys conducted by the same surveyor at multiple locations on the same date (i.e., at least two surveys conducted on the same date by the same surveyor). We then calculated the time elapsed between the end of one survey and the start of the next. The average time between surveys that occurred on the same date by the same surveyor was 43 minutes.[119] Figures 3 and 4 below show the distribution of times between surveys (e.g., there were 2,905 occurrences in the dataset when

[119] *See* OGI Travel Time Analysis Final (included as Attachment E) for a full printout of the figures.

the elapsed time between the end of one survey and the beginning of the next was less than 15 minutes).

Figure 3

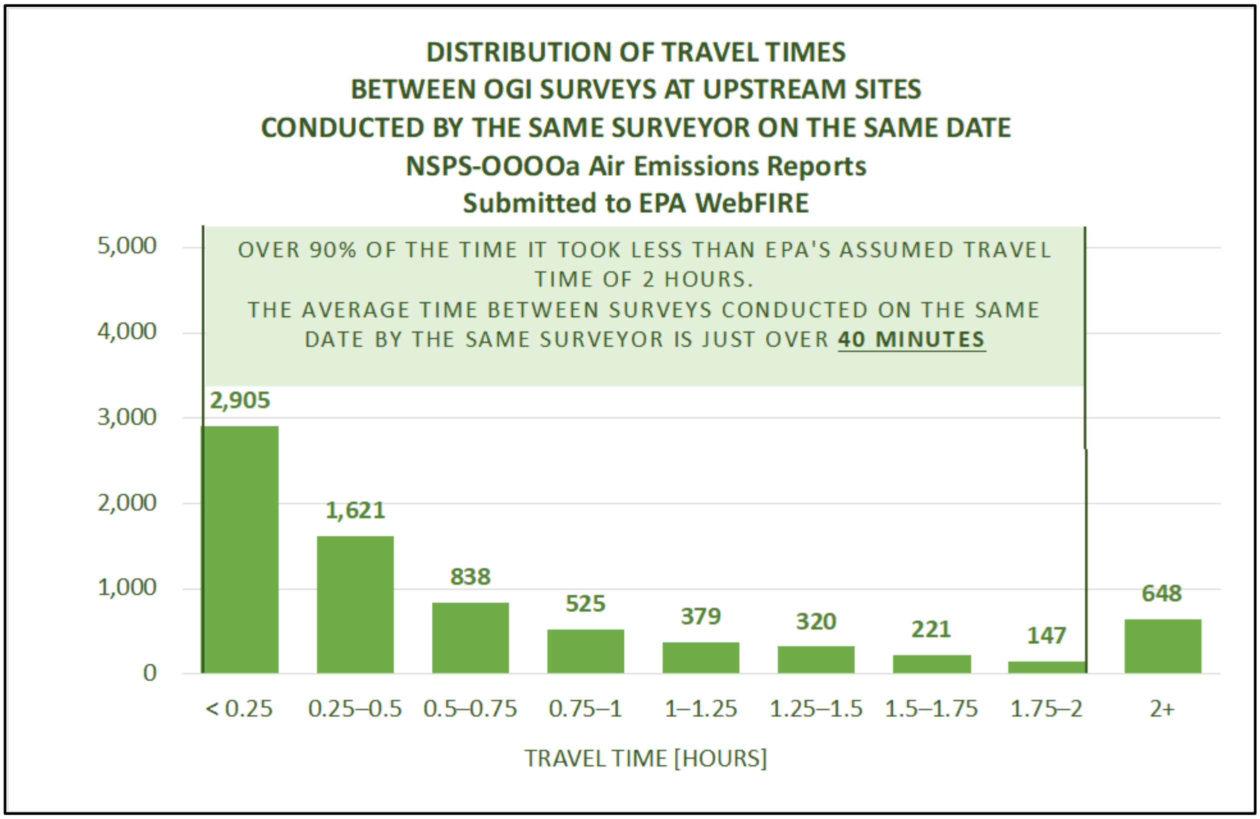

Figure 4

	TIME BETWEEN SURVEYS – NUMBER AND PERCENTAGE						DATAPOINTS
	< 30 MINS	30 MINS–1 HR	1–1.5 HRS	1.5–2 HRS	2+ HRS	AVG [MINS]	
TIME ELAPSED BETWEEN SURVEYS	4,526	1,363	699	368	648	43	7,604
	60%	18%	9%	5%	9%		

< 2 HRS	91%
< 1.5 HRS	87%
< 1 HR	77%
< 30 MINS	60%

Given that our analysis encompassed every reported survey time and all of the available information on travel, we believe EPA should use both the 30 minute median survey time and 43 minute average travel time in its analysis, for a total combined time of 73 minutes. Sites subject to OOOOa fugitive monitoring are likely more complex than the average site, and we expect that survey times for OOOOb/c sites would typically be shorter.

Using our revised survey and travel time, as well as a revised labor rate and recordkeeping and reporting costs, which avoid double counting as described in our initial comments,[120] we recreated EPA's cost-effectiveness tables from the Technical Support Document (TSD)

[120] 2022 Joint Environmental Comments, *supra* note 1, at 72–84.

accompanying the supplemental proposal.[121] For each model plant, we analyzed the single pollutant cost-effectiveness of OGI monitoring under six scenarios:

- <u>Scenario 1m</u>: includes revised median survey and average travel time, labor rate, and record keeping / reporting costs;
- <u>Scenario 2m</u>: includes revised median survey and average travel time, and labor rate; and
- <u>Scenario 3m</u>: includes revised median survey and average travel time.
- <u>Scenario 1a</u>: includes revised average survey and travel time, labor rate, and record keeping / reporting costs;
- <u>Scenario 2a</u>: includes revised average survey and travel time, and labor rate; and
- <u>Scenario 3a</u>: includes revised average survey and travel time.[122]

For the single wellhead-only model plant, we find that semiannual OGI is within the range EPA considers cost-effective under scenarios 1m and 1a using both leak rate assumptions (0.5% and 1% leak rates). For both the multi-wellhead-only and the well site and centralized production facility model plants, we find that quarterly OGI is cost-effective and incrementally cost-effective under all scenarios. These findings support the reasonable cost of EPA's proposed standards and also support our recommendations for more frequent monitoring at certain site types.

c. Audio, visual, & olfactory inspections

We support EPA's inclusion of AVO inspection requirements because we believe regular site visits and upkeep are important at *all* sites and will help to prevent and mitigate fugitive emissions and equipment failures. Regular AVO inspections can also help secure additional emissions reductions from large and very obvious equipment failures. The proposed AVO requirements can help ensure operators actually address issues they find at sites indicating a potential leak rather than turning a blind eye. Especially at marginal and declining sites, lack of maintenance can lead to persistent and long-lasting leaks, and can sometimes result in major failures.[123] AVO can therefore serve an important additional purpose aimed at site hygiene and preventative maintenance that is not necessarily encompassed by OGI or periodic screening, which are both aimed at reacting *after* a problem has occurred. To ensure the preventative value of AVO is realized, EPA should alter the regulatory language to require action when "evidence of a potential leak or likely future leak is found at any time."

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[121] *See* U.S. Env't Protection Agency, *Supplemental Background and Technical Support Document for the Proposed NSPS and EG*, Tables 5–10 to 5–17b (Oct. 2022) (Doc. ID. No. EPA-HQ-OAR-2021-0317-1578) [hereinafter Supplemental TSD].

[122] These tables are included with our comments as PDF's located in the Revised OGI Cost Effectiveness Tables (included as Attachment F) and each is also accompanied by the associated revised cost evaluation spreadsheet with revisions and notes in green.

[123] Jacob Deighton et al., *Measurements show that marginal wells are a disproportionate source of methane relative to production*, 70 J. Air Waste Mgmt. Assoc. 1030, 1030–42 (2020), https://www.tandfonline.com/doi/epdf/10.1080/10962247.2020.1808115?needAccess=true&role=button (finding that "the main driver of emissions from the wells visited is neglect. The state of maintenance at these wells was poor. Often, pumpjacks, tanks, and other infrastructure were rusty and sometimes appeared to have temporary fixes to just keep the well mechanically operational. . . . Some wells looked like they had not been serviced in years.").

We also support the AVO inspection requirements at all sites, including small wells and wellhead-only sites, for the reasons described below regarding end-of-life well issues. Regulatory exemptions can result in irresponsible operations and business models that aim to keep declining wells in production beyond their useful lives in order to avoid plugging costs and exploit tax benefits.[124] This can lead to rusted, overgrown, and unmaintained sites that leak methane, create dangerous conditions, and are prone to orphanage.[125] Requiring the responsible operator to inspect these sites and fix visible problems will help combat these issues while disincentivizing business models centered on accumulating and neglecting declining sites. We also encourage EPA to require that operators take action to prevent fugitive emissions when an AVO inspection indicates leaks and equipment failures are imminent.[126]

We further believe that AVO inspection requirements should also apply to sites opting for alternative periodic screening, described later in these comments. Aerial screening does not serve the same site upkeep and preventative maintenance purposes as AVO inspections. Allowing sites opting for the alternative to forgo AVO inspections means they may not be visited for years (depending on where in the matrix they fall) and could therefore fall into states of neglect and disrepair, making them more prone to leaks and equipment failures that might be under the detection limit of the screening technology. Including these sites in AVO requirements is also important for ensuring the equivalency of emissions reductions.[127]

Our compliance report analysis described above finding much shorter OGI survey and travel times in reported data underscores that EPA is likely overestimating those same figures (and thus costs) in its assumptions about AVO as well.[128] Indeed, travel times for AVO surveys are likely to be the same as for OGI, and inspection times will be shorter for AVO than OGI.

d. *Affected and designated facilities*

We strongly support EPA's revised affected and designated facility definitions for fugitive monitoring and the proposed subcategories, which move away from an approach based on potential emissions to an approach based on site characteristics and equipment types present. EPA is now proposing to expand the affected facility definition to include the collection of fugitive emissions components at all well sites and centralized production facilities with no exemptions. Well sites are then subcategorized and subject to varied monitoring requirements based on the presence and number of equipment types that are known to cause emissions. EPA has also revised the definition of fugitive emissions components to exclude components that are subject to other standards and compliance monitoring requirements. Below, we explain why

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[124] *See, e.g.*, Zachary R. Mider & Rachel Adams-Heard, *An Empire of Dying Wells,* Bloomberg (Oct. 2021), https://www.bloomberg.com/features/diversified-energy-natural-gas-wells-methane-leaks-2021/.

[125] Deighton et al., *supra* note 123, at 1030–42.

[126] *See, e.g.*, *id.* (observing rusted components, temporary fixes, and overgrown vegetation at marginal wells and proposing that neglect was the primary driver of emissions).

[127] *See* Supplemental RIA, *supra* note 110, at 235.

[128] Supplemental TSD, *supra* note 121, at 5–18 ("a travel time of 1.25 hours round trip was assumed at the same hourly rate for operators as is used for the development of a monitoring plan and other actions. Inspection times ranging from 15 minutes (single wellhead only well sites) to 1 hour (centralized production facilities) to account for the added complexity at larger sites, were assumed.").

EPA's equipment-based approach is appropriate and scientifically-justified. We then discuss each of the subcategories and provide recommendations for improvements.

i. Equipment-based approach

In our previous comments, we submitted extensive evidence outlining the serious problems with an approach that based monitoring requirements on potential emissions calculated by operators using an equation that did not adequately predict actual emissions nor account for equipment failures.[129] Existing non-measurement-based estimation methods, like the potential to emit calculation in the initial proposal, tend to misrepresent emissions and, in particular, miss super-emitters. We therefore urged EPA to move toward an equipment-based approach where monitoring requirements depend on the presence of equipment at a site and that equipment's potential to leak or fail. We also submitted extensive evidence showing that sites excluded from monitoring under EPA's initial proposal frequently emit at higher rates than other sites, can be super-emitter sources, and cumulatively may represent over 50% of total well-site methane emissions. We therefore urged EPA to ensure these smaller sites are subject to regular monitoring.[130]

It is appropriate to base monitoring frequency on the presence of certain types of equipment at a site because such equipment has been commonly observed as the source of large emission events through numerous field studies. The presence of major equipment also indicates higher component counts, which correlate to a greater probability of fugitive emissions. For example, Zavala-Araiza et al. (2017) explains that abnormal process conditions, both persistent or episodic, include "failures of tank control systems, malfunctions upstream of the point of emissions (for example, stuck separator dump valve resulting in produced gas venting from tanks), design failures (for example, vortexing or gas entrainment during separator liquid dumps) and equipment or process issues (for example, over-pressured separators, malfunctioning or improperly operated dehydrators or compressors)."[131] Another study by Lyon et al. found that emissions from tank vents and hatches accounted for roughly 90% of all detected hydrocarbon sources emitting more than 3–10 kg per hour.[132] Lyon et al. also observed emissions from separator pressure relief valves, dehydrators, and flares.

A more recent study, Rutherford et al., found that tanks are the largest emission source and biggest reason for disagreement between the study results and EPA Greenhouse Gas Inventory (GHGI) data.[133] Rutherford et al. also found that flare methane emissions are underestimated in the GHGI, and that pneumatics and separators are also large sources of emissions.[134] Tyner and Johnson (2021) also recently found that "[m]ore than half of emissions were attributed to three

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[129] 2022 Joint Environmental Comments, *supra* note 1, at 84–91.
[130] *Id.* at 91–108.
[131] Daniel Zavala-Araiza et al., *Super-emitters in natural gas infrastructure are caused by abnormal process conditions*, 8 Nature Commc'n 14012 (2017), https://www.nature.com/articles/ncomms14012#Sec6 [hereinafter Zavala-Araiza, *Super-emitters*].
[132] David Lyon et al., *Aerial surveys of elevated hydrocarbon emissions from oil and gas production sites*, 50 Env't. Sci. Tech. 4877 (2016), https://pubs.acs.org/doi/full/10.1021/acs.est.6b00705 [hereinafter Lyon et al., *Aerial Surveys*].
[133] Jeffrey Rutherford et al., *Closing the methane gap in US oil and natural gas production emissions inventories*, 12 Nature Commc'n. 4715, at Figure 3 (2021), https://www.nature.com/articles/s41467-021-25017-4.
[134] *Id.*

main sources: tanks (24%), reciprocating compressors (15%), and unlit flares (13%)."[135] Robertson et al. (2020) found that simple sites with less equipment had lower emissions than those with more equipment.[136] And Zavala-Araiza et al. (2015) found that stuck separator dump valves and tank flashing events were causes of super-emitters.[137]

EDF's PermianMAP project has observed many emission events from tanks and flares.[138] Helicopter surveys found 79% of methane plumes were from tanks; and among marginal wells, 17% of complex sites (with multiple pieces of equipment) had emissions, while none were detected at "pump-jack only" sites.[139] Ravikumar et al. (2020) similarly found the largest emissions from tanks, concluding that "[t]he outsized role of tanks in contributing to overall methane emissions at natural gas facilities has been a defining feature in many recent studies, and points to a critical need for tank-focused LDAR regulations."[140]

Our review of OOOOa compliance reports further supports EPA's equipment-based approach.[141] We downloaded over 20,000 compliance reports and isolated 80,121 reported component leaks from instrument-based fugitive emissions surveys. We then categorized each reported leak by component type and by equipment type when possible. We were able to assign an equipment category to 46% of reported component leaks. Table 2 below contains information on leaks that could be categorized by equipment type.

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[135] David Tyner & Mathew Johnson, *Where the Methane Is—Insights from Novel Airborne LiDAR Measurements Combined with Ground Survey Data*, 55 Env't Sci. Tech. 9773 (2021), https://pubs.acs.org/doi/pdf/10.1021/acs.est.1c01572.

[136] Anna 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't. Sci. Tech. 13926 (Oct. 15, 2020), https://pubs.acs.org/doi/10.1021/acs.est.0c02927.

[137] Daniel Zavala-Araiza et al., *Reconciling divergent estimates of oil and gas methane emissions*, 51 Proc. Nat'l Acad. Sci. 15597 (2015), https://www.pnas.org/content/112/51/15597.

[138] Observed emissions by equipment type: Tank-Vent 42.96%, Tank Thief Hatch 33.43%, Flare Stack 14.54%. PermianMAP, *Prevalence of Emissions by Equipment Type*, (Observed emissions by equipment type: Tank-Vent 42.96%, Tank Thief Hatch 33.43%, Flare Stack 14.54%).

[139] *Id.*

[140] Ravikumar 2020, *supra* note 104 (citing Lyon et al. *Aerial Surveys*, *supra* note 132).

[141] For a full description of this analysis and methodology, *see* Env't Def. Fund, *OOOOa Compliance Report Analysis Methodology*, *supra* note 116.

Table 2

Equipment Type	Count of Reported Leaks	% of Reported Leaks Categorizable by Equipment
Tank	16470	63.0
Pneumatic Controller	6009	23.0
Flare/Control	1871	7.2
Separator	699	2.7
Compressor	446	1.7
Heater-treater	234	0.9
Vapor Recovery Unit	214	0.8
Wellhead	67	0.3
Pump	44	0.2
Gas/Sales line	33	0.1
Dehydrator	31	0.1
Closed Vent System	17	0.1

EPA's proposed equipment-based approach aligns with the substantial body of science and data characterizing emissions from certain types of failure-prone equipment, in particular flares, storage tanks, and gas-driven pneumatic controllers. As described below, the data supports adding separators to this list of failure-prone equipment so that any site with a separator is subject to quarterly OGI. The table below summarizes the proposed requirements, which requires monitoring at all sites while imposing more rigorous inspection obligations on more complex sites.

Table 3

Site Type	Inspection Requirement
Well sites and centralized production facilities[142] with failure-prone equipment[143]	Quarterly OGI + Bimonthly (6x) AVO (attempt 30 days, final repair 60)
Wellhead only well sites with two or more wellheads	Semiannual OGI + Quarterly AVO (attempt 30 days, final repair 60)
Single wellhead sites with one piece of non-failure-prone equipment[144]	Quarterly AVO (repair w/n 15 days)
Single wellhead only sites	Quarterly AVO (repair w/n 15 days)
Compressor stations	Quarterly OGI + Monthly AVO (attempt 30 days, final repair 60)
Well sites and compressor stations on Alaska North Slope	Annual OGI (attempt 30 days, final repair 60)

Another benefit of the tiered equipment-based approach is that it incentivizes operators to eliminate polluting sources from their sites by designing sites with minimal emissions points and electrifying certain equipment types. For example, instead of creating five separate well sites with tanks and other major processing equipment that would all be subject to quarterly OGI, EPA's proposed structure incentivizes the use of centralized production facilities and wellhead-only well sites. By utilizing this type of design, operators can focus monitoring resources on the centralized production facility.

ii. Well sites & centralized production facilities

We support EPA's subcategorization of well sites, which ensures that more complex sites and those with failure-prone equipment are subject to quarterly OGI and bimonthly AVO. As

[142] Centralized production facilities include one or more storage vessels and all equipment at a single surface site used to gather, for the purpose of sale or processing to sell, crude oil, condensate, produced water, or intermediate hydrocarbon liquid from one or more offsite natural gas or oil production wells.
[143] All sites with (1) one or more controlled storage vessels, (2) one or more control devices, (3) one or more natural gas-driven pneumatic controllers or pumps, or (4) two or more other major production and processing equipment (see footnote below).
[144] Equipment allowed at these sites include: a single separator, glycol dehydrator, centrifugal or reciprocating compressor, heater/treater, or uncontrolled storage vessel. By this definition, a small well site could only potentially contain a well affected facility (for well completion operations or gas well liquids unloading operations that do not utilize a CVS to route emissions to a control device) and a fugitive emissions components affected facility. No other affected facilities, including those utilizing CVS (such as pneumatic pumps routing to control) can be present for a well site to meet the definition of a small well site).

described above, we believe EPA has properly ensured that sites with equipment types that contain higher component counts and are commonly associated with fugitive emissions and super-emitters are subject to quarterly OGI. We believe that EPA should add any sites with a separator to this category, thereby excluding a single separator from the list of permissible equipment at small well sites. Separators are a known source of large fugitive emission events, as shown through the studies and data described above.

In the supplemental proposal's discussion of the permissible equipment at small well sites, EPA's stated expectation is that AVO surveys alone will successfully identify wellhead leaks and thief hatch leaks:

> Surface casing valves and thief hatches on an uncontrolled storage vessel are the most likely emissions sources for these small well sites. As discussed for single wellhead only well sites, the surface casing valve can easily be identified as open or closed during an AVO inspection and would not require the use of OGI to detect the leak. Similarly, the use of OGI is not necessary to be able to identify if a thief hatch is not closed. For example, the hatch may be fully open, left unlatched and "chattering" with fluctuations from the storage vessel pressures, or have visible indications of liquids such as staining around the hatch.[145]

EPA clearly explains why fugitive emissions from wellheads and tanks can be detected and remedied without an OGI survey. However, this justification is not provided for separators, even though numerous studies find that separator malfunctions are a source of large emissions events.[146] In the DOE marginal well study, three of the ten largest measured emissions events stemmed from separator dump valves.[147] This study identified separators with ages as high as 72 years in their survey of field sites and found that 26% of separators at light oil sites and 67% of separators at gas sites had detectable emissions using OGI.[148] Separators are well-documented as a source of frequent and often large emissions events, and they are also a source of smaller emissions that may not be detectable through AVO.[149]

Separators are also a very prevalent piece of failure-prone equipment at smaller well sites. We used 2016 Information Collection Request (ICR) data to analyze single well sites with a single piece of major processing or production equipment. Our analysis found that 11% of the well sites reported to the ICR would meet EPA's proposed definition of a small well site. Of those sites, 77% had a single separator present. EPA's proposed definition of small well sites therefore likely

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[145] 87 Fed. Reg. at 74731.
[146] Rutherford et al., *supra* note 133 (Figure 3 shows separators as large source of emissions within the equipment leak category.); Zavala-Araiza, *Super-emitters, supra* note 131 (In the second paragraph of their discussion, they cite stuck separator dump valves, design failures like vortexing or gas entrainment during separator liquid dumps, and equipment or process issues such as over-pressured separators as some of the many abnormal process conditions observed in field campaigns.)
[147] Richard L. Bowers, *Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells* Report at 19 (2022), https://www.osti.gov/biblio/1865859. [hereinafter "Bowers Report"]
[148] Richard L. Bowers, *Quantification of Methane Emissions from Marginal (Small Producing) Oil and Gas Wells* at Slide 21 (Aug. 2021), https://netl.doe.gov/sites/default/files/netl-file/21CMOG_OG_Bowers.pdf.
[149] Zavala-Araiza, *Super-emitters*, *supra* note 131; Lyon et al., *Aerial Surveys*, *supra* note 132.

exempts many single well sites with separators from regular OGI inspections. This is concerning given the prevalence of large emissions events originating from separators.

EPA notes in modeling the rule's impacts that small well sites were not treated differently than single wellhead-only sites on the assumption that these sources would have comparable emissions. However, because separators will be present at the majority of sites falling into EPA's proposed small well site category, we do not believe that assumption is correct. Based on our review of EPA's model plants, we believe that the emissions profile of a single wellhead site with a separator is much closer to the well site model plant and the multiple wellhead only model plant than the single wellhead only model plant.

Using Rutherford 2021 emission factors, we estimate the emissions from small sites with separators to be 3.94 tpy per gas site and 1.13 tpy per oil site. Applying the direct ICR equipment proportions (77% of small sites have a separator, 2% have a reciprocating compressor, 1% have a dehydrator, 19% have a tank) yields average Rutherford emissions of 3.71 tpy and 1.04 tpy for gas and oil wells, respectively. Even when averaged with the lower DOE study emission factors, the average baseline emissions from small sites is much closer to the 0.5% leak generation rate baseline emissions of multi-wellhead only sites. We believe that when equipment types at small sites are accurately represented, these sites more closely represent the multiple wellhead only or well site model plants.

OGI surveys are effective at detecting emissions from separators. Our analysis of upstream OGI surveys in OOOOa compliance reports finds that reported leaks from separators are common and only eclipsed in frequency by tanks, pneumatic devices, and flares.[150] However, we do not have data to indicate that AVO surveys can effectively detect emissions from this component. Continuing to include sites with separators in the small well site category will likely lead to significant fugitive emissions and super-emitters that could otherwise be detected and repaired with OGI. EPA should therefore remove a single separator from the list of major production and processing equipment that can be present at a small well site and ensure any site with a separator is subject to quarterly OGI. We estimate that doing so will increase the emissions coverage of OGI to over 80% of total emissions, thereby ensuring greater overall reductions.

iii. Multiple wellhead-only sites

We support EPA's proposal to require semiannual OGI monitoring at wellhead-only sites with more than one wellhead. Numerous studies have found emissions from wellheads and the risk of greater emissions and larger leaks increases with the number of wellheads.[151] Further, as new sites are designed as wellhead-only with offsite centralized tank batteries, wellhead-only sites are increasingly higher producing and may have large throughput. A leak from the wellhead could

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[150] *See* Table 6, *infra*, (finding 699 separator leaks).

[151] Deighton et al., *supra* note 123 (measuring wellhead emissions and finding that "[s]ome wells were emitting all or more of the reported gas produced at each well, or venting gas from wells with no reported gas production"); Stuart 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 (measuring wellhead emissions and finding a "mean of 8.8% of production lost (leaked) at the wellhead.").

therefore lead to very significant emissions.[152] Finally, as described above and determined by EPA, semiannual OGI monitoring is cost-effective at multiple wellhead-only well sites.[153]

If EPA does not adopt our recommendation to require quarterly OGI at single wellhead sites with separators, we urge EPA to require semiannual OGI at those sites. For the same reasons described above, we believe ongoing OGI is important for detecting emissions from separators. Our analysis of EPA's model plants also shows that single wellhead sites with separators have an emissions profile that is more similar to well sites and multiple wellhead only sites than to wellhead only sites. We believe this justifies similar treatment and supports ongoing OGI inspection requirements.

iv. Wellhead-only & small well sites

EPA, relying on data from the 2016 ICR, estimates that approximately 95,000 well sites nationwide, or approximately 12 percent of the total nationwide well site count, would meet the definition of "small well site." EPA's analysis also estimates that roughly 50% of total well sites nationwide would be classified as either single wellhead-only well sites or small well sites. Based on our own analysis, we find that 408,700 well sites, responsible for 24% of fugitive emissions, would fall into one of these categories and would therefore be subject only to quarterly AVO inspections.[154]

We urge EPA to consider instrument-based inspections or a single initial OGI inspection at these sites to further drive down emissions. At minimum, EPA should provide an alternative semiannual OGI compliance option for any site subject to the proposed quarterly AVO only requirements. While we support the proposed AVO requirements, AVO cannot detect emissions as effectively as OGI, especially emissions from certain equipment types. If only subject to AVO, it is possible emissions and leaks from these sites may go undetected. As described above, and in our initial comments, smaller and marginal sites can be significant sources of emissions and the equipment types at these sites, including wellheads, have been observed as significant sources. If large emissions events are detected at these sites through the Super-emitter Response Program, we recommend the site be required to reclassify and conduct quarterly OGI (or the equivalent alternative).

While stakeholders have raised concerns about compliance burdens associated with monitoring at smaller wells, we have again confirmed through an updated analysis of well ownership data that the vast majority of marginal wells (92%) are owned by large companies with average revenues of over $100 million per year. Our updated analysis is presented here and more fully in attachment H.[155]

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[152] *See, e.g.*, Mike Ludwig, *Ohio Gas Well Was Spewing Methane Pollution Three Weeks After Blowout*, TruthOut (Mar. 2018), https://truthout.org/articles/ohio-gas-well-is-still-spewing-methane-pollution-three-weeks-after-blowout/.
[153] *See* Revised OGI Cost Effectiveness Tables Folder (included as Attachment F)
[154] Env't Def. Fund., *Methodology for Estimating Emissions Covered by AVO-Only Standards* (Attachment G).
[155] Env't Def. Fund, *Updated Marginal Well Operatorship Analysis* (included as Attachment H). Our updated analysis uses improved Enverus from 2022. This impacted EDF analysis of well operatorship based on Enverus 2019 production data; however, the overarching conclusion remains the same. With respect to coverage, the number

Table 4

Well Site Ownership and Gross Revenue by Operator Size

Operator (# 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
operators						
< 5	7,038	13,406	95%	2%	$1,431	$0.20
5 to 25	3,215	40,840	93%	6%	$5,800	$1.80
Small operators	*10,253*	*54,246*	*94%*	*8%*	*$7,230*	*$0.71*
Large operator:						
25 to 100	1,814	90,041	93%	13%	$12,398	$7
> 100	915	601,328	81%	78%	291,043	$318
Large operators	*2,729*	*691,369*	*82%*	*92%*	*$303,441*	*$111*
TOTAL	**12,982**	**745,615**	**83%**	**100%**	**$310,671**	**$24**

Sources: Enverus, EIA

Notes:

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.

5) Data are restricted to well sites comprised of 100 wells or fewer.

6) Offshore wells are excluded.

7) Data are restricted to wells with nonzero cumulative production, with nonzero 2019 production and a first production date prior to 2020.

8) Data are restricted to the following well types from the Enverus database: Oil, Gas, Oil & Gas, CBM, Cyclic Steam, Steam Flood, Waster

We support EPA's proposed requirements to maintain thief hatches closed and sealed and AVO monitoring to verify compliance with this standard. Inspections are necessary to ensure compliance with the "closed and sealed" requirement for thief hatches, which are a known large source of emissions and are commonly observed left open.

v. End-of-life & abandoned wells

We strongly support EPA's proposal to ensure that all sites are affected facilities subject to some form of ongoing monitoring. Significant emissions, including super-emitter events, have been

of well sites with non-zero oil and gas production in 2019 increased from ~704k to ~745k and the corresponding number of operators increased from ~12k to ~13k. The percentage of marginal wells owned by large operators remains the same at 92%. Total 2019 gross revenue generated by large operators decreased slightly but remains above $300B ($303B down from $329B). The average 2019 gross revenue per operator decreases slightly but remains above $100M ($111M down from $128M).

observed at marginal wells,[156] shut-in wells,[157] abandoned wells,[158] and wellheads,[159] underscoring the importance of regular monitoring at these sites until they are properly plugged. These sites are typically older and declining in production, meaning they are less likely to be regularly visited or prioritized for equipment upgrades and repairs. Aging and poorly maintained equipment at these sites can easily fail and leak. EPA's proposed AVO monitoring requirements therefore address an important problem and can both help to prevent emissions and mitigate existing or recurring problems.

In our initial comments, we highlighted our concerns that exempting declining sites from regulatory requirements could exacerbate end-of-life well issues.[160] This could happen in at least two ways. First, exempting declining sites from inspection requirements means they can exist in a regulatory gray area, subject neither to standards for active wells nor standards for well closure. This may be desirable to operators who seek to avoid facing the costs of plugging and closure.[161] Second, regulatory exemptions for declining sites may increase their attractiveness to potential buyers, some of whom are likely to become insolvent or lack the funds for proper closure.[162] As leading operators seek to reduce emissions, they may offload underperforming and high-emitting assets to private companies lacking environmental commitments or those with business models aimed at prolonging the life of declining assets. This "transferred emissions problem" is a growing concern that can negatively impact emission reduction efforts.[163]

EPA's proposal to require ongoing fugitive monitoring, recordkeeping, and reporting until wells are properly plugged will help address end-of-life well problems and minimize emissions. The proposed standards would require operators to submit a well closure plan within 30 days of the cessation of production from all wells at the well site or centralized production facility that includes: (1) the steps necessary to close all wells at the well site, including plugging of all wells; (2) the financial requirements and disclosure of financial assurance to complete closure; and (3) the schedule for completing all activities in the closure plan. Owners and operators would also have to report any changes in ownership at individual well sites so that it is clear who is responsible until the site is plugged and closed. By ensuring these wells do not sit perpetually in a regulatory gray area, EPA standards can help ensure that fugitive emissions are minimized while facilitating proper closure at the end of a well's productive life.

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[156] Mark Omara et al., *Methane emissions from US low production oil and natural gas well sites*, 13 Nat. Commc'n 2085 (2022), https://www.nature.com/articles/s41467-022-29709-3; Deighton et al., *supra* note 123.
[157] Amy Townsend-Small, *Direct measurements from shut-in and other abandoned wells in the Permian Basin of Texas indicate some wells are a major source of methane emissions and produced water,* Env't Rsch. Letters (2021), https://iopscience.iop.org/article/10.1088/1748-9326/abf06f.
[158] Mary Kang et al., *Direct measurements of methane emissions from abandoned oil and gas wells in Pennsylvania*, 51 PNAS 18173 (2014), https://www.pnas.org/doi/10.1073/pnas.1408315111; James Williams et al., *Methane Emissions from Abandoned Oil and Gas Wells in Canada and the United States*, 55 Env't Sci. Tech. 563 (2020), https://pubs.acs.org/doi/10.1021/acs.est.0c04265.
[159] Riddick et al., *supra* note 151; Bowers Report, *supra* note 147, at 19.
[160] 2022 Joint Environmental Comments, *supra* note 1, at 108-09.
[161] *See, e.g.*, Zachary R. Mider and Rachel Adams-Heard, *supra* note 124.
[162] *See id*.
[163] Env't Def. Fund, *Transferred Emissions: How Risks in Oil and Gas M&A Could Hamper the Energy Transition* (2022), https://business.edf.org/insights/transferred-emissions-risks-in-oil-gas-ma-could-hamper-the-energy-transition/.

We support EPA's proposal to require closure plans and post-closure OGI surveys to demonstrate that plugging has been effective. These requirements will help facilitate plugging in accordance with applicable standards while defining a clear point in time after which a well is no longer an affected facility. We recommend that EPA develop sampling methods for post-closure OGI surveys to ensure plugging has been effective.

EPA should ensure all types of abandoned wells are clearly covered by the requirements and clarify who would be subject to these requirements. For example, there are "zombie wells" that are abandoned and not in operation but have a known solvent owner. We believe that these wells should be subject to EPA fugitive monitoring standards unless and until they are properly plugged, or otherwise declared orphans and then addressed through orphan well plugging programs.

We also recommend that EPA further define what is required in the financial demonstration. For example, operators may claim that a statewide bond is sufficient to cover their plugging costs. If a statewide bond is relied on, EPA should require operators to say how much of that bond is allocated to each of their wells. In many cases, the minimum required statewide bond is not actually sufficient to cover the costs of plugging all of an operator's wells in the state. Available financial assurance for well closure should therefore be calculated and demonstrated on a per-well basis. For example, if the operator has posted a $100,000 blanket bond to cover 500 wells in the state, the operator should report that $200 are available for well plugging activities. Recent literature estimates typical well plugging costs of $20,000 for plugging only and $75,000 for plugging and surface reclamation, with horizontal wells sometimes reaching hundreds of thousands of dollars.[164] The table below shows how much money would be available per well for closure assuming a $20,000 cost, underscoring the inadequacy of most statewide bonds.[165]

[164] Daniel Raimi et al., *Decommissioning Orphaned and Abandoned Oil and Gas Wells: New Estimates and Cost Drivers*, 55 Env't. Sci. Tech. 10224 (2021), https://pubs.acs.org/doi/10.1021/acs.est.1c02234.
[165] The full analysis is presented in Env't Def. Fund, *Well Bonding Tables* (included as Attachment I).

Table 5

Financial Assurance per Well for State Blanket Bonds

(USD per Onshore Well Covered)

	Onshore Wells Covered by Blanket Bond								
State	**5**	**10**	**25**	**50**	**100**	**200**	**500**	**1,000**	**10,000**
California[1]	N/A	N/A	$8,000	$4,000	$4,000	$2,000	$4,000	$2,000	$300
Louisiana[2]	$10,000	$5,000	$10,000	$5,000	$5,000	$2,500	$1,000	$500	$50
New Mexico[3]	$10,000	$5,000	$3,000	$1,500	$1,250	$1,250	$500	$250	$25
New Mexico (Inactive)[4]	$30,000	$30,000	$20,000	$20,000	$10,000	$5,000	$2,000	$1,000	$100
Ohio	$3,000	$1,500	$600	$300	$150	$75	$30	$15	$2
Oklahoma[5]	$20,000	$10,000	$4,000	$2,000	$1,000	$500	$200	$100	$10
Pennsylvania[6]	$28,000	$14,000	$11,600	$8,600	$4,300	$3,000	$1,200	$600	$60
Texas[7]	$5,000	$2,500	$2,000	$1,000	$500	$1,250	$500	$250	$25
West Virginia	$10,000	$5,000	$2,000	$1,000	$500	$250	$100	$50	$5

Source: State adminstrative codes and regulations.

Notes:

(1) California blanket bonds are only available for operators with 20 or more wells. Different financial assurance amount are required for other wells types (e.g., offshore, geothermal, injection, etc.).

(2) Louisiana blanket bonds require different financial assurance amount other wells types (e.g., offshore, inland, bay, etc.).

(3) New Mexico bonding amount reflects financial assurance required for active wells only.

(4) New Mexico bonding amount reflects financial assurance active and inactive wells.

(5) Oklahoma blanket bond requirements presented are the most stringent option available to operators and are consistent with a $100,000 blanket bond. Blanket bonds can be as low as $25,000 dollars with $100,000 set as the maximum allowable amount. Some operators can be exempt for posting financial assurnace if they can domenstration financial health in other forms such as a minimum amount of net worth.

requirement for unconvetional wells deeper than 6,000ft. Requirements are less stringent for shallow unconventional wells and all other wells that are not

(7) Texas blanket bonds require different financial assurance amounts for other well types (e.g., offshore, bay).

The financial demonstration required by EPA should contain an estimate of actual closure costs per well so that EPA and stakeholders can evaluate whether the operator's finances are actually sufficient to close the well in question. Financial requirements to close the well should be based on actual plugging costs from operators' previous plugging operations or the best available data for the well type and region, and should account for the relevant state or federal agency plugging requirements. Subject to confidentiality, these financial requirements and assurance disclosures should be made publicly available and easy to download. EPA should also require operators to submit a financial demonstration immediately in the first annual report and to reaffirm it each year.

We recommend that in addition to the schedule for completing the well closure, operators report the physical activities needed to close the well and the requirements of the relevant state and federal agencies. The submitted schedule should enumerate all steps necessary to close each well and the estimated timing of each. We recommend that EPA require the final well closure plan to be submitted 30 days *prior* to the cessation of production of *any* well located at the site. Public reporting should also occur when the well has been properly plugged so regulators can verify closure and so EPA can de-list the site.

vi. Compressor stations

Compressor stations contain large numbers of fugitive emissions components and are a major known source of emissions.[166] For the reasons articulated in our initial comments and based on our revised cost-effectiveness analysis, we urge EPA to require bimonthly OGI at all compressor stations.[167] Bimonthly monitoring at compressor stations is well within EPA's cost-effectiveness range and should be required to ensure greater emission reductions from these large sources.[168]

e. Repair requirements

EPA is proposing to require a first attempt at repair within 30 days of identifying fugitive emissions, with final repair required within 30 days of the first attempt, for a potential total of 60 days. We believe this is unnecessarily long and could lead to large emissions going unmitigated for up to two months. Repair timelines can significantly affect overall mitigation,[169] and EPA's projections of emissions reductions achieved by the rule assume only a 30-day delay between detection and repair.[170] EPA's projected reductions will not be realized if repairs are allowed to extend beyond 30 days.

A 30-day repair timeline is feasible and is already required by leading states, like Colorado and New Mexico.[171] We therefore urge EPA to require a first attempt at repair within 15 days of detection and a final repair within 15 days of the first attempt, for a maximum of 30 days between detection and final repair.

EPA should eliminate the "technically infeasible" exemption language from the repair requirements and only allow extended repair timelines in the specified instances. This language is too open-ended and is not necessary given that EPA has already specified the situations in which a repair would be technically infeasible. Additionally, EPA should include a requirement that inspection crews attempt to complete repairs at the time leaks are detected when safe and feasible. This practice is already the norm for leading operators and should be encouraged by EPA.

EPA should also ensure that documentation and reporting occurs when an OGI or AVO survey detects emissions but the operator determines that the emissions are from a permissible event or part of normal operations that does not require repair. This will help to align requirements with the alternative screening option while allowing EPA to track and ensure that operators are taking appropriate follow-up action after detecting emissions. We also recommend that EPA require the

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[166] *See, e.g.*, Evan Sherwin et al., *Quantifying oil and natural gas system emissions using one million aerial site measurements*, Preprint (2023) https://www.researchsquare.com/article/rs-2406848/v1 (finding that emissions from midstream facilities can make up 50 percent of the total in certain basins).
[167] 2022 Joint Environmental Comments, *supra* note 1, at 112–15.
[168] Daniel Zimmerle et al., *Methane Emissions from Gathering Compressor Stations in the U.S.*, 54 Env't. Sci. Tech. 7552 (2020), https://pubs.acs.org/doi/10.1021/acs.est.0c00516.
[169] *See* Felipe J. Cardoso-Saldaña, *Tiered Leak Detection and Repair Programs at Oil and Gas Production Facilities* 325 (2022), https://chemrxiv.org/engage/chemrxiv/article-details/636d4595afea7fcd1c9f5f67.
[170] *See* Supplemental RIA, *supra* note 110, at 228.
[171] *See* Colo. Code Regs. § 1001-9-D-II.E.7; N.M. Code R. § 20.2.50.116(E) (2023).

initial monitoring survey to occur earlier so that companies can address problems sooner and mitigate potentially large emissions that would otherwise go undetected for up to 90 days.

Importantly, EPA should align OGI and AVO follow-up and repair requirements for control device failures with those described in section 60.5398b(b)(4)(iv). Misalignment between the scope of monitoring and follow-up and repair requirements between the OGI program and the alternative could disincentivize use of the alternative. We therefore urge EPA to ensure control devices are monitored during OGI surveys for compliance with the requirements of section 60.5413b, and are subject to parallel root cause and corrective action requirements if problems are detected.

f. Regulatory text & definitions

Below, we provide recommendations for revising the regulatory language defining the affected facility, subcategories, and definitions, including the fugitive emissions component definition. Our recommended changes to the text are denoted using underlines for additions and strikethroughs for deletions. Our recommended changes are intended to apply to the regulatory text of OOOOb and OOOOc whenever applicable.

The proposed regulatory text at section 60.5365b reads: "You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (l) of this section for which you commence construction, modification, or reconstruction after November 15, 2021." Paragraph (i) defines the affected facility as "[e]ach fugitive emissions components affected facility, which is the collection of fugitive emissions components at a well site, centralized production facility, or a compressor station." We encourage EPA to amend this to explicitly include tank batteries. If EPA does not make this change, it should clarify in the well site definition that tank batteries at a well site are part of the well site fugitive emissions component affected facility.

EPA has also proposed a number of definitions that impact the applicability of the fugitive monitoring requirements. Below we quote EPA's proposed definitions, followed by our proposed changes and rationale.

Centralized production facility

EPA's proposal: "*Centralized production facility* means one or more storage vessels and all equipment at a single surface site used to gather, for the purpose of sale or processing to sell, crude oil, condensate, produced water, or intermediate hydrocarbon liquid from one or more offsite natural gas or oil production wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline. Process vessels and process tanks are not considered storage vessels or storage tanks. A centralized production facility is located upstream of the natural gas processing plant or the crude oil pipeline breakout station and is a part of producing operations."

Recommended changes: "*Centralized production facility* means one or more storage vessels and all equipment at a ~~single~~ surface site used to gather~~, for the purpose of sale or processing to sell,~~

crude oil, condensate, produced water, ~~or~~ intermediate hydrocarbon liquid, or any other produced hydrocarbons, from one or more ~~offsite~~ natural gas or oil ~~production~~ wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline. ~~Process vessels and process tanks are not considered storage vessels or storage tanks.~~ A centralized production facility is located upstream of the natural gas processing plant or the crude oil pipeline breakout station and is a part of producing operations."

Rationale: We recommend eliminating words that could support overly narrow interpretations of what constitutes a centralized production facility. We also recommend encompassing any site used to gather any produced hydrocarbons, again to prevent overly narrow interpretations. If EPA does not eliminate the word "offsite" from this definition, it must clarify that tank batteries at or near well sites are part of the well site fugitive emissions component affected facility.

First attempt at repair

EPA's proposal: "*First attempt at repair* means an action taken for the purpose of stopping or reducing fugitive emissions to the atmosphere. First attempts at repair include, but are not limited to, the following practices where practicable and appropriate: Tightening bonnet bolts; replacing bonnet bolts; tightening packing gland nuts; or injecting lubricant into lubricated packing."

Recommended changes & rationale: EPA's definition is too broad and could allow actions without any probability of leading to a successful repair to be interpreted as an "attempt." We therefore recommend tying the attempted action to the outcome, which is a successful repair. EPA should include language that makes clear the "attempt" must be one that, if completed, would successfully mitigate the emissions. We also encourage EPA to broaden the non-exhaustive list of examples. Many fugitive emissions will require repairs that are much more significant than the list EPA has included.

Fugitive emissions

EPA's proposal: "*Fugitive emissions* are defined as any indication of visible emissions observed from a fugitive emissions component using optical gas imaging or an instrument reading of 500 parts per million (ppm) or greater using Method 21 of appendix A-7 to this part."

Recommended changes & rational: Fugitive emissions must also be defined to include any emissions detected through the alternative fugitive monitoring standards at section 60.5398b from a fugitive emissions component. As proposed the definition is limited to OGI and Method 21. We suggest amending the definition or otherwise clarifying in section 60.5398b that any emissions detected using the procedures described in section 60.5398b are considered fugitive emissions if the source is a fugitive emissions component.

Major production and processing equipment

EPA's proposal: "*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, for the purpose of determining whether a well site is a wellhead only well site."

Recommended changes & rationale: EPA should eliminate the last clause of the definition because major production and processing equipment is also referenced in section 60.5397b(g)(1)(iii)(D) for purposes beyond determining whether a well site is a wellhead only site. We therefore recommend that qualifier be eliminated. EPA should also add language to ensure that all types of storage vessels are included.

Open-ended valve or line or open-ended vent line

EPA's proposal: "*Open-ended valve or line or open-ended vent line* means any valves, except safety relief valves, having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through open piping."

Recommended changes & rational: EPA should eliminate the exception for safety relief valves. Safety relief valves can malfunction and cause unintended and fugitive emissions, and should therefore be considered a fugitive emissions component.

Tank battery

EPA's proposal: "*Tank battery* means a group of all storage vessels that are manifolded together for liquid transfer. A tank battery may consist of a single storage vessel if only one storage vessel is present."

Recommended changes & rationale: EPA should clarify that if a tank battery exists at or near a well site, it is considered part of the well site for purposes of the fugitive emissions standards in sections 60.5397b and 60.5398b. EPA must clarify that tank batteries are subject to fugitive monitoring requirements regardless of where they are located, including tank batteries that are not part of a centralized production facility.

Well site

EPA's proposal: "*Well site* means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. For the purposes of the fugitive emissions standards at §60.5397b, a well site does not include:

(1) UIC Class II oilfield disposal wells and disposal facilities;

(2) UIC Class I oilfield disposal wells; and

(3) The flange immediately upstream of the custody meter assembly and equipment, including fugitive emissions components, located downstream of this flange."

Recommended changes & rationale: EPA should make clear that a well site includes all the equipment at the site to ensure that all fugitive emissions components associated with equipment at the site are subject to the monitoring and repair standards.

Fugitive emissions component

In the November 2021 proposal, EPA proposed an expanded definition of fugitive emissions component that was intended to capture the known sources of large emission events. We supported the broader definition but raised concerns about potential ambiguity about the scope of fugitive monitoring and what is considered a fugitive emission.[172] First, we recommended 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. To avoid ambiguity, we recommended that EPA include certain equipment types like separators in the definition so monitoring of separator dump valves and components on all other equipment would clearly be required.

We also recommended including tank batteries and other site types in the definition to avoid potential ambiguity about where fugitive monitoring is required. 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 centralized production facilities, which are known large sources of fugitive emissions. Finally, we recommended that EPA include a non-exhaustive but more comprehensive list of fugitive emission components and equipment to help ensure they are not overlooked during fugitive monitoring and to reduce the potential for interpretations that might incorrectly narrow the scope of fugitive monitoring.[173]

In this supplemental proposal, EPA has proposed a new definition of fugitive emissions component, including the following changes: adding yard piping to the list of components; revising how thief hatches are defined; and excluding control devices, pneumatic controllers, and pneumatic pumps. EPA's proposed definition reads:

> Fugitive emissions component is any component that has the potential to emit fugitive emissions of methane or VOC at a well site, centralized production facility, or compressor station, including valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to 40 CFR 60.5411b, thief hatches or other openings on a storage vessel not subject to 40 CFR 60.5395b, compressors, instruments, meters, and yard piping.

We support the inclusion of yard piping, and again urge EPA to clarify that the list of components is non-exhaustive. EPA should also clarify that fugitive emissions components can exist on any type of equipment at any location at the site. And again, we urge EPA to include tank batteries or otherwise cross reference the affected facility definitions to reduce any potential ambiguity about the types of sites that are subject to fugitive monitoring. We recommend that EPA revise the language to ensure fugitive emissions components include *all* components on *all* types of equipment located *anywhere* at a well site, centralized production facility, tank battery, or compressor station.

In the November 2021 proposal, EPA proposed that all thief hatches and other openings on controlled storage vessels would be considered fugitive emissions components, including those

[172] 2022 Joint Environmental Comments, *supra* note 1, at 68–72.
[173] *See id.*

storage vessels that would be subject to control as storage vessel affected facilities. This meant that openings on storage vessels could be two different types of affected facilities. In this proposal, EPA is defining fugitive emissions components to include all thief hatches and other openings on storage vessels that are not also subject to control as storage vessel affected facilities. This includes thief hatches and other openings on both uncontrolled storage vessels and storage vessels that are controlled for other purposes but not subject to the proposed control requirements. We support this structure as long as all storage vessels and controls on storage vessels are regularly monitored. EPA's newly proposed compliance monitoring requirements ensure this, and we believe this structure is appropriate given the underlying tank control standards.

EPA is also not defining control devices as fugitive emissions components and has proposed separate monitoring requirements to ensure control devices operate as intended, including monthly Method 22 inspections that we strongly support, as described later in these comments. We agree with this approach but urge EPA to also require that flares and control devices be monitored for compliance assurance during all fugitive emissions surveys, both under the OGI and AVO program and under the alternative periodic screening options. Control devices and flares are among the most commonly-observed sources of methane emissions, including super-emitter events.[174] It is therefore critical that they are regularly inspected and monitored to ensure proper operation. Monitoring flares and control devices during fugitive emission surveys poses very little additional burden and can ensure emission events are avoided. Large methane slip, unlit flares, and other types of malfunctions are all violations of EPA's proposed and existing requirements for the operation of control devices.[175] We therefore support regular monitoring for compliance assurance purposes both through EPA's proposed requirements and during fugitive emissions surveys.

Likewise, we support EPA's approach to monitoring natural gas-driven pneumatic controllers and natural gas-driven pneumatic pumps. Both of these equipment types regularly malfunction and cause significant emissions, and even when operating as intended they can be significant sources of emissions. As discussed in section IV.D, we support EPA phasing out gas-driven pneumatics, and we support the compliance assurance monitoring requirements for any remaining gas-driven pneumatics routing emissions to a process or control device that achieves a 100% reduction.

We also urge EPA to make clear that fugitive monitoring would be required at any source receiving a variance under OOOOc or otherwise not subject to the standards applicable to pneumatics, control devices, covers and closed vent systems, and tanks. If given a variance, those sources would not be required to monitor for compliance assurance and any leaks would therefore properly be characterized as fugitive emissions and must be monitored during fugitive emissions surveys. In sum, we urge the agency to ensure that entire sites are comprehensively monitored (whether as part of LDAR or for compliance assurance) during every survey and we believe that emissions from equipment in violation of underlying standards are properly characterized as violations rather than fugitives.

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[174] *See, e.g.*, Genevieve Plant et al., *Inefficient and Unlit Natural Gas Flares Both Emit Large Quantities of Methane*, 377 Sci. 6614 (2022), https://www.science.org/doi/10.1126/science.abq0385.
[175] *See* Proposed 40 C.F.R. § 60.5412b(a)-(c).

As part of our review of OOOOa compliance reports, we also analyzed the most commonly reported leaking components.[176] To do this, we pulled the raw data from the "Fugitive Emissions Components" tab of each report. We then reviewed every unique type of component that operators reported as leaking, seeking to categorize each by component type and equipment type when possible. After this process, the dataset contained 56,836 reported component leaks from 174 unique component types and 20 types of equipment. The table below displays the most commonly reported component leaks in upstream fugitive emissions surveys using OGI.

This information supports our proposed revisions to the definition of fugitive emissions component, underscoring the need for EPA to clarify that the list of components in the definitions is non-exhaustive. It also confirms the importance of monitoring at failure-prone equipment types that contain the most commonly leaking fugitive emissions component types.

2. Advanced technology alternative

We strongly support EPA's proposed alternative periodic screening option for LDAR at well sites, centralized production facilities, and compressor stations that would allow for the use of advanced methane detection technologies. Innovation in methane detection technologies and deployment methods is advancing rapidly and EPA has taken a careful, technology-neutral approach that will enable the use of these technologies for regulatory compliance. EPA's proposed approach provides operators and technology providers with flexibility, while ensuring most critically that these technologies are used in a way that ensures emission reductions equivalent to OGI at all sites nationwide. In this section, we discuss the legal structure of the proposed alternative, EPA's Fugitive Emissions Abatement Simulation Tool (FEAST) modeling to determine equivalence, our own FEAST modeling, and the regulatory requirements, including monitoring frequency, follow-up, and repair. Our primary recommendation is that EPA should require ongoing ground-based inspections at all sites as a backstop.

As an optional alternative to the OGI-based approach described above, EPA proposes to allow operators to use advanced methane detection technologies at varying frequencies (and with varied OGI pairings) depending on detection capabilities—a "matrix" approach. The requirements also vary by site type, tracking the subcategories described above. The proposed changes to the alternative screening option are intended to support the deployment and utilization of a broader spectrum of advanced measurement technologies than the initial proposal. EPA has therefore proposed two matrices of options that are expected to achieve emission reductions equal to or greater than OGI:

[176] For a full description of the methodology, *see* Env't Def. Fund, *OOOOa Compliance Report Analysis Methodology*, *supra* note 116.

Table 6

Component Type	Count of Reported Leaks	% of Reported Leaks
Thief Hatch	11,310	19.9
Connector	6,749	11.9
Valve	5,655	9.9
Pneumatic Controller (unspecified)	5,171	9.1
Pressure Relief Device	3,668	6.5
Connection	3,220	5.7
Hatch	2,487	4.4
Tank (unspecified)	2,366	4.2
Flare (unspecified)	1,793	3.2
Fitting	1,330	2.3
Enardo	1,242	2.2
Pressure Relief Valve	1,026	1.8
Flange	887	1.6
Level Control/Level Controller	829	1.5
Gasket	664	1.2
Regulator	635	1.1

Table 7

Quarterly OGI Subject Sites	
Detection Capability	Frequency
≤1 kg/hr	Quarterly + Annual OGI
≤2 kg/hr	Bimonthly (6x)
≤4 kg/hr	Monthly
≤10 kg/hr	Bimonthly (6x) + Annual OGI
≤30 kg/hr	Monthly + Annual OGI

Table 8

Semiannual OGI & AVO Subject Sites	
Detection Capability	Frequency
≤1 kg/hr	Semiannual
≤2 kg/hr	Triannual
≤5 kg/hr	Triannual + Annual OGI
≤15 kg/hr	Quarterly + Annual OGI
≤30 kg/hr	Monthly + Annual OGI

We believe the frequencies and detection thresholds included in the matrices are largely appropriate and will ensure that equivalent emission reductions occur at all sites nationwide. Our own FEAST modeling results using nationally-representative emissions distributions generated results similar to what is included in the matrices (described more below). We also note that EPA's results are intuitively correct—given that OGI has a detection threshold below 1kg/hr, any technology that is less sensitive must be used at a higher frequency to achieve the same emissions reductions. As the detection threshold increases, so does the fraction of total emissions that cannot be detected by that technology. Therefore, to achieve the same level of emissions reduction as quarterly (or semiannual) OGI, technologies with higher detection thresholds must be used more frequently. And with very high detection thresholds, it is not possible to achieve the same level of reductions, regardless of frequency, because too large of a fraction of total emissions exists below the detection threshold.

Prior to deploying a technology for regulatory compliance, EPA would have to approve the technology as meeting the parameters outlined in the proposal and matrices. EPA is proposing to streamline the pathway for technology developers and other entities to seek the agency's approval for the use of advanced measurement technologies under the alternative screening option. Approved technologies could then be deployed following the same operational parameters under which they were approved.

An operator choosing the screening approach must submit a monitoring plan identifying the sites, test methods, technology vendor, planned frequencies, follow-up survey plans, and repair plans. Upon detection of emissions, ground-based OGI surveys are required and repairs must be completed within 30 days of the screening survey. Root cause analysis and corrective action are required if the emissions are due to failure of a control device, a cover, or a closed vent system.

We support EPA's proposed structure, matrices, deployment and repair requirements, and technology approval process. Below, we explain our support and offer suggestions for additional improvements.

a. Legal structure

EPA's decision to provide an alternative pathway for advanced methane monitoring technologies is appropriate given the emerging nature of many of these technologies and the significant promise they entail. Based on cost information that is available, we also understand that these technologies are typically much cheaper to deploy than OGI (half the cost or less).[177] Allowing advanced technologies as an alternative to OGI through a matrix is a reasonable decision that fits well with EPA's section 111 authority and the Clean Air Act more broadly. The Clean Air Act is a technology-forcing statute,[178] and section 111 "looks toward what may fairly be projected for the regulatory future, rather than the state of the art at present."[179] EPA can therefore design frameworks that accommodate reasonably anticipated improvements in detection capabilities, rather than the limitations of currently in-use technologies, particularly where (as here) the anticipated advancements are optional rather than mandatory. Most importantly, in providing any alternative compliance option, EPA must ensure that emission reductions equal to or greater than the BSER will occur.[180]

EPA proposes the BSER for fugitive emissions as combinations of OGI and AVO work practice standards under CAA section 111(h)(1) that vary by site subcategory. The D.C. Circuit has indicated that "EPA may provide sources with multiple work practice compliance options if EPA demonstrates that at least one of these options is cost effective and 'expressly provides for the alternative in the standard.'"[181] As described above and in the supplemental proposal, the OGI-

[177] 2022 Joint Environmental Comments*, supra* note 1, at 116–19.
[178] *Union Elec. Co. v. EPA*, 427 U.S. 246, 257 (1976).
[179] *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973).
[180] *See, e.g.*, U.S. Env't Prot. Agency, Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources. Background Technical Support Document for the Final New Source Performance Standards. 40 CFR Part 60, Subpart OOOOa, at 56–57 (May 2016), https://www.regulations.gov/document/EPA-HQ-OAR-2010-0505-7631 (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).
[181] 73 Fed. Reg. 78199, 78200 (Dec. 22, 2008) (citing *Arteva Specialties S.R.R.L., d/b/a KoSa v. EPA*, 323 F.3d 1088, 1092 (DC Cir. 2003)).

based BSER is cost-effective and EPA has proposed an alternative work practice of "periodic or continuous screening with advanced measurement technology instead of OGI and AVO monitoring according to minimum detection sensitivity of technology."[182] This voluntary (but once chosen, enforceable) alternative is supported by precedent,[183] and EPA has appropriately followed the statutory requirements by ensuring equivalent emission reductions will occur.

b. EPA's FEAST modeling

EPA's decision to use the Fugitive Emissions Abatement Simulation Tool (FEAST) to model the effectiveness of different methods and advanced technologies is likewise reasonable.[184] FEAST is a customizable, open-source modeling framework developed to evaluate the effectiveness of different LDAR programs at oil and gas facilities. Model inputs include the number and type of emissions sources, a leak generation rate by emission source type, a distribution of leak rates when a leak is generated, and the probability of the selected method detecting a leak of a given size. FEAST can therefore evaluate the effectiveness of different LDAR approaches, as well as voluntary programs undertaken by operators.

In this section, we discuss the assumptions and inputs that EPA used in its FEAST modeling, including the technology assumptions, the emission scenarios, and the deployment methods. We believe that all of the inputs used by EPA are reasonable, appropriate, and ensure that advanced technologies deliver emission reductions commensurate with OGI across diverse basins. EPA chose inputs and made assumptions based on nationally applicable factors and considerations. This is both appropriate and required by section 111, which applies across the country to sources in different oil and gas producing regions and basins. While technologies and methods may perform differently in different regions and under varying conditions, EPA is required to ensure that equivalent performance will occur everywhere and under all conditions. EPA's modeling does this and we therefore support the results, which also generally align with the results of independent modeling conducted with nationally applicable input assumptions.

i. Technology assumptions

Technology parameters are an important input for the FEAST model that affect the results and should also inform EPA's technology approval process, which applies to new technologies before they are deployed in the field for compliance purposes. Default FEAST inputs for technology parameters are based on probability of detection curves derived through controlled testing studies. Because technologies may perform differently under varying meteorological and geographic conditions, it is also possible to alter the technology parameters based on the intended uses. For example, an operator evaluating the effectiveness of aerial technologies that it intends to deploy in North Dakota might alter the technology inputs to reflect decreased performance in windy and snowy conditions. Conversely, an operator in the Texas Permian might assume better technology performance due to relatively more consistent weather and geographical conditions there.

[182] 87 Fed. Reg. at 74708–09.
[183] *See, e.g.*, 73 Fed. Reg. 78200 (Dec. 22, 2008).
[184] *Fugitive Emissions Abatement Simulation Toolkit*, SET Lab, https://www.arvindravikumar.com/feast/ (last visited Feb. 13, 2023).

EPA appropriately excluded regionally variable factors like wind speed and snow cover, relying instead on broadly-applicable and averaged assumptions derived from controlled testing. Because technologies permitted for compliance may be deployed anywhere across the country at any time, it would not be possible nor reasonable for EPA to attempt to evaluate performance or set standards based on varying meteorological and geographical conditions. Such considerations are instead better resolved during the new technology approval process or AMEL applications.

ii. Emissions scenarios

The FEAST model outputs depend on the emissions distributions used to conduct the modeling. In general, using a heavy-tailed emissions distribution—meaning one where a small number of large emission events represent a significant portion of the total—will result in a relatively greater effectiveness of frequent screening with less-sensitive technologies. With a less-heavy tailed distribution—meaning one consisting of many smaller leaks—more sensitive technologies that can detect those smaller leaks will be more effective. In FEAST, this means that OGI monitoring results in a greater effectiveness with a more normalized emissions distribution, while a technology like aerial monitoring results in a relatively greater effectiveness with a heavy-tailed distribution.

While heavy-tailed distributions have been found across basins (and in all basins, a subset of emission events disproportionately contribute to total emissions), in most basins, the bulk of the emissions are still generated smaller leaks. Thus capturing the large emission events is necessary but not sufficient and the approach, across basins, should capture the entire distribution of leaks. Because emissions distributions vary significantly by basin, ensuring that technologies can achieve equivalent reductions across basins requires using an averaged distribution that reflects both individually smaller (but collectively significant) leaks as well as super-emitters.

The default FEAST emissions distribution is based on five field measurement studies and contains all the leaks found in those studies. EPA excluded leaks that would not be addressed through the proposed monitoring requirements and supplemented the default distribution with two more recent studies. In addition, EPA accounted for large, super-emitting events with data from Cusworth et al., 2021. The default FEAST distribution categorizes emissions into leaks, abnormal vents, and permissible vents. Because permissible vents are not mitigated by LDAR standards, EPA properly excluded this category of emissions.

The resulting averaged emissions distribution aligns with the regulatory structure and accounts for equipment component leaks, tank leaks, and large emission events based on data from seven studies across diverse basins. The distribution also accounts for the intermittency of emissions because it is based on studies that consist of actual field observations and rigorous statistical analyses. Emissions captured in these studies are those that were present at the time of observation. The resulting snapshot in time of emissions includes some events that were emitting and some that were intermittent, thereby incorporating intermittency. These studies further address intermittency through statistical analysis.

As should be expected, FEAST modeling shows that a higher survey frequency improves performance when super-emitters are taken into account, regardless of the intermittency. While intermittent events can be missed if their average duration is lower than the survey frequency, FEAST modeling also shows that the emission reductions from advanced technologies compared to OGI are directionally higher as the duration of the super-emitter events increases. This is because longer super-emitter events result in a larger contribution to total cumulative emissions from super-emitters, which can be mitigated even with higher detection threshold technologies. While it is true that more empirical data is needed to further characterize average duration of intermittent super-emitter events across different basins,[185] current FEAST modeling captures the impact of super-emitter distributions in terms of the contribution to total emissions. This allows FEAST to produce robust frequencies for both OGI and advanced technologies to achieve significant emission reductions. Because many emissions from oil and gas sources are intermittent, frequent monitoring with OGI, advanced technologies, or both is necessary to ensure adequate mitigation.

To better understand the potential implications that altering the duration parameter in FEAST could have on EPA's proposed frequencies and mitigation effectiveness generally, we recreated EPA's modeling but adjusted the persistence of super-emitters.[186] EPA's modeling does not alter the duration parameter, but instead holds super-emitters constant like all other types of emissions in the model. We remodeled the same detection thresholds used by EPA with the same input assumptions but altered the duration of super-emitters to 5, 15, 45, and 90 days. We found that this sensitivity analysis would not impact equivalency or the frequencies proposed by EPA in the matrices. Given the results of this sensitivity analysis, and for the reasons described in this section, we do not recommend that EPA alter the duration parameter for super-emitters in its equivalency modeling.

When the duration parameter is shortened for super-emitters, it results in less overall emissions and also in super-emitters making up a smaller fraction of total emissions. This means that more frequent screening (i.e., monthly) detects and can therefore mitigate more super-emitters than less frequent methods (i.e., quarterly). But because the overall contribution of super-emitters is significantly lower with shorter durations, the more frequent detections are less important to overall mitigation and do not impact equivalence. These results also underscore the need for an annual OGI pairing with the higher detection threshold technologies. With greater intermittency and lesser overall emissions from super-emitters, the annual OGI pairing becomes increasingly important for mitigating other types of emissions that then represent a larger portion of the total. Results of this modeling are displayed below and the entire analysis is located in attachment J.[187] Figure 5 shows how the relative contribution of super-emitters to total emissions declines with greater intermittency.

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[185] Cardoso-Saldaña, *supra* note 169, at 20 (2022), ("There is also lack of data on the temporal characteristics of high-emitters, which is a very sensitive parameter. Future work should focus on obtaining information on duration of high-emitters and on root-cause analysis, which will be particularly relevant when doing LDAR modeling coupled with a process based simulator that includes routine emissions and with a finer simulation temporal resolution.").

[186] *See* Arvind P. Ravikumar, *Role of Intermittency in Methane Emissions Reduction* (Feb. 2023) (included as Attachment J).

[187] *Id.*

Figure 5

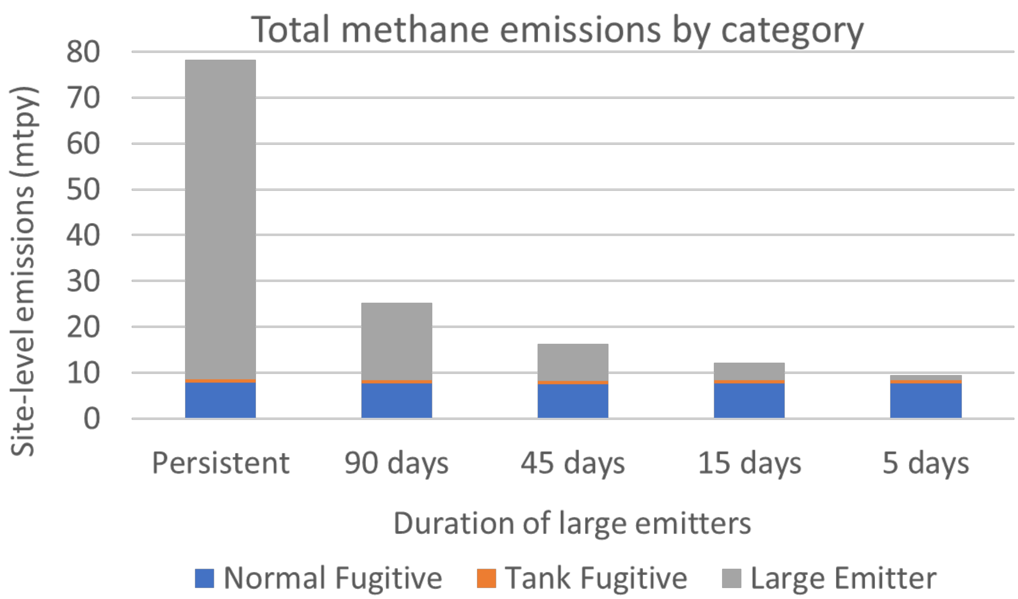

Table 9 below shows the effects on equivalency when the duration parameter is altered to account for intermittent super-emitters. It shows site-level emissions after quarterly OGI surveys and periodic screening surveys with three detection thresholds (with and without an annual OGI pairing) for three durations parameters (persistent, 90 days, and 15 days). As shown, the results do not support altering the frequencies proposed in EPA's matrices (equivalency condition shown in orange).

Table 9

	Intermittency Persistent			Intermittency 90 days			Intermittency 15 days		
Site-wide detection Threshold (kg/h)	OGI (quarterly)	Monthly survey	Monthly survey + annual OGI	OGI (quarterly)	Monthly survey	Monthly survey + annual OGI	OGI (quarterly)	Monthly survey	Monthly survey + annual OGI
	Metric tons per year (mtpy)								
4		9.3	6.7		7.5	5.0		6.9	4.3
10	16	15.2	7	12.8	15.5	7.2	5	13.9	5.4
30		39.1	7.7		38.4	7.4		39.8	7

While it is important to understand the impacts of different intermittency assumptions on equivalence, the available data and modeling does not support revisiting the frequencies in EPA's proposed matrices. EPA's FEAST modeling is supported by seven different peer-reviewed studies based on field observations that incorporate intermittency and capture typical conditions. Absent explicit, peer-reviewed data characterizing intermittency that significantly affects the emissions distribution used in FEAST, additional modeling scenarios that alter the persistence parameter are not necessary and would have minimal impact on the outcomes. We therefore recommend that EPA not alter the FEAST modeling underlying the proposed matrices. EPA should, however, assess the potential impact of intermittency based on data and information submitted during the comment period, such as that described above.

Numerous commenters have submitted modeling results, including Joint Environmental Commenters. In particular, some commenters have claimed, sometimes on the basis of their modeling results, that aerial screening technologies at lower frequencies, like quarterly, can be equally effective as quarterly OGI.[188] This claim, however, is specific to certain basins or operations with a disproportionately high share of super-emitters. Because that is not the case nationally, it would be arbitrary for EPA to rely on basin- or operator-specific assumptions about emissions distributions. Doing so would likely reduce screening frequencies in higher-emitting basins, resulting in approaches that would not be effective in other basins with normalized emissions distributions. And while less frequent monitoring in higher-emitting basins may lead to greater percentage reductions than it would elsewhere, it will not lower emissions to a level commensurate with the rest of the country. Capturing super-emitters is necessary but not sufficient and overall performance should not be sacrificed by only focusing on capturing individual high-emitting events. Further, with full implementation of EPA's proposal, including repeated LDAR surveys, the prevalence of large emission events should be greatly reduced. If EPA's modeling included a too heavy-tailed distribution, it would result in a matrix that would quickly become outdated and ineffective as super-emitters are reduced.[189]

To illustrate the differences in mitigation effectiveness across basins, we also conducted FEAST modeling of OGI, Aerial 1 (lower detection threshold with and without annual OGI), and Aerial 2 (higher detection threshold with and without annual OGI) using two basin-specific emissions distributions.[190] For a heavy-tailed distribution, we used data from the Permian, and for a less-heavy tailed distribution, we used data from the Marcellus. Both emissions distributions include recent data on super-emitters from the respective basins. The results show how different technologies perform in different basins and demonstrate how higher detection threshold technologies are far less effective in basins with more normalized distributions. This underscores the importance of EPA using a nationally-averaged distribution to ensure equivalent reductions and account for the decreasing prevalence of super-emitters anticipated in coming years and with implementation of EPA's proposal. The results also underscore the need to ensure permissible technologies are sensitive enough to detect the significant fraction of total emissions--often the majority--that are caused by smaller emissions. Takeaways from the basin-specific modeling are summarized below.

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[188] *See, e.g.*, Pioneer Natural Resources USA, Inc., Comments on Standards of Performance for New, Reconstruction, and Modified Sources and Emissions Guidelines for Existing Sources (Doc. ID. No. EPA-HQ-OAR-2021-0317-0820) (Jan. 31, 2022), https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-0820.

[189] EPA may consider addressing outlier situations through the AMEL process. However, for the reasons discussed in this section, any AMEL approaches should be time-limited and EPA should continually revisit the underlying assumptions and update them for accuracy.

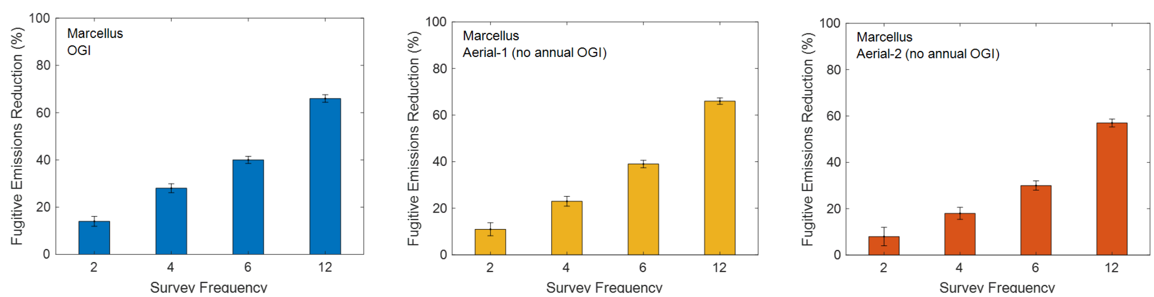
[190] Arvind P. Ravikumar, FEAST:US – Basin-level Modeling of LDAR Program for Methane Emissions Mitigation (included as Attachment K).

Table 10

Category	Marcellus	Permian	Explanation
OGI	Better mitigation at lower survey frequencies	Mitigation comparable to Marcellus only at high survey frequency	High contribution from super-emitters in Permian → only high survey frequencies are effective
Aerial-1 + Annual OGI	Similar performance to OGI at all survey freq.	Similar performance to OGI at all survey freq.	Lower detection threshold detects most super-emitters in both basins (better than OGI at low survey freq.)
Aerial-2 + Annual OGI	Significantly diminished performance compared to OGI/Aerial-1	Similar performance to OGI at all survey freq.	Higher detection threshold implies better performance in Permian than in Marcellus basin
Effect of annual OGI	5 – 10% reduction in mitigation across all survey freq.	2 – 5% reduction in mitigation across all survey freq.	Contribution of small emitters to total emissions higher in Marcellus than Permian
Uncertainty	2 – 4% standard errors (higher at lower survey freq.)	5 – 10% standard error (higher at lower survey freq.)	Higher contribution from intermittent super-emitters in Permian → more spread in detection/mitigation

The equivalency modeling results from the Marcellus demonstrate that aerial technologies cannot achieve the same level of reductions as OGI when used at the same frequency. The addition of an annual OGI survey is particularly important under this scenario, as it helps reduce the smaller leaks below the detection thresholds of the aerial technologies. As shown below, quarterly OGI is more effective than aerial technologies in a basin with a more normalized emissions distribution.

Figures 6, 7, and 8



The full results of this modeling are presented in attachment K and underscore the need for more frequent screening and, in some cases, an annual OGI pairing, in order to achieve equivalency across diverse basins. The results align with and support EPA's proposed matrices and annual OGI pairings.

Over the past two years, we have conducted FEAST modeling with different types of input assumptions, including using basin-specific emission distributions and the intermittency assumptions described above, as well as the nationally-representative modeling submitted with our initial comments.[191] The key takeaways from this work include:

- Using rigorous and nationally representative emissions distributions is critically important—for EPA's section 111 standards, a nationally-averaged distribution is necessary to ensure advanced technologies deliver equivalent or better emission reductions across diverse basins;
- When super-emitters are less prevalent in the emissions distribution—as is the case in many basins already and should result more broadly from implementation of EPA's final regulations—higher-detection-threshold technologies are less effective;
- Altering intermittency assumptions through the duration parameter in FEAST has no significant impact on equivalence and reduces the overall contribution of super-emitters, thereby increasing the importance of OGI pairings with high-detection-threshold technologies;
- At higher detection thresholds, reductions eventually flatline even when frequency is increased—this is because a certain fraction of emissions cannot be detected or mitigated by these technologies;
- An annual OGI pairing can help address the fraction of emissions that fall below a technology's detection threshold but will not significantly increase total reductions in most cases; and
- Technologies with very high detection thresholds may not reliably achieve reductions equivalent to quarterly OGI, especially in the longer-term, and are therefore not suitable for regulatory deployment.

The results of our modeling work across a range of scenarios and with varied inputs demonstrate that EPA's FEAST modeling and proposed matrices are robust and resilient to a range of sensitivities.

c. *Matrices and recommendations*

In this section, we discuss EPA's proposed technology matrices derived from FEAST, the proposed work practice requirements for regulatory deployment, and our recommendations for improvements.

i. Quarterly OGI matrix

EPA's proposed quarterly OGI matrix aligns with our independent FEAST modeling results across a variety of scenarios and we therefore support the proposed frequencies. Our results for aerial technologies paired with annual OGI are similar to EPA's, and we believe the proposed frequencies are appropriate. In coming years, detection capabilities are likely to improve and we support EPA's inclusion of options that will drive this improvement. Last, while EPA's FEAST results show that the addition of an annual OGI survey is necessary for equivalence for only some of the options, we encourage EPA to nevertheless require a universal annual OGI backstop

[191] *See* Arvind P. Ravikumar, FEAST:US – Alternative LDAR Programs for Representative US O&G Production Facilities National Slides (included attachment L to 2022 Joint Environmental Comments, *supra* note 1).

and ensure that any higher detection threshold options contain OGI pairings. We believe this is necessary to mitigate smaller (but cumulatively significant) persistent leaks that are detected under EPA's BSER determination for OGI but unlikely to be detected through advanced screening. The OGI pairing will also become increasingly important as super-emitters are reduced and begin to contribute less to total emissions.

ii. Semiannual OGI & AVO matrix

For sites that would be subject to semiannual OGI or quarterly AVO (wellhead only and small well sites), EPA has proposed a different matrix that would achieve reductions equivalent to semiannual OGI. We support the frequencies and detection thresholds in this matrix also, and in particular believe the annual OGI pairings with the higher detection threshold technologies are appropriate. Sites subject to this matrix will often be producing very little and may not regularly experience large emission events. Consequently, many emissions at these sites are likely to be smaller leaks that may be missed by high detection threshold screening technologies. To mitigate these leaks thus requires the use of a more sensitive technology, like OGI.

Most operators choosing the alternative advanced monitoring option will likely contract with a methane mitigation provider and will choose the alternative for a grouping of assets or all their assets. Operators typically also have mixed assets, meaning they have a variety of site types, some of which will fall into different monitoring subcategories. Screening all of an operator's sites based on the most stringent applicable requirement would therefore pose minimal additional burden in many cases. For example, if an operator owns twenty-two well sites in a basin, half of which would fall into the quarterly OGI matrix, and half of which would fall into the semiannual OGI matrix, the operator would likely screen all the sites pursuant to the more stringent requirement. In light of the potential efficiency advantages to applying the same approach to all sites in a geographic area, operators should be permitted to apply the most protective version of the matrix to groupings of sites.

EPA should also require some form of ongoing OGI or AVO inspections at all sites complying with this matrix as a backstop. For the reasons described in section IV.B.d.v, we think that AVO inspections are particularly valuable for declining end-of-life wells and reducing the risk of orphaning. Without some form of regular, ground-based inspection, operators may never visit these sites and preventative maintenance may never occur. Ground-based inspections better serve the purposes of regular upkeep and site hygiene that are important for end-of-life wells in particular, and should therefore be required at all wellhead-only and small well sites.

Last, we believe that EPA should revisit the assumptions underlying the matrices in the future. As large emission events are reduced through implementation of EPA's proposed standards, we expect that emissions distributions across basins will become less heavy tailed. This means that higher detection threshold options will become less effective over time as the fraction of total emissions below their detection threshold increases. Therefore, to achieve reductions equivalent to OGI, frequencies will need to increase and detection thresholds will need to decrease. Further, we expect that costs and improved detection capabilities will obviate the need for higher detection threshold options in the future.

iii. Work practice requirements

We support EPA's proposed alternative fugitive monitoring standards and provide the following recommendations for improvements.

Require initial monitoring within 30 days. The early stages of production often involve abnormal process emissions and operational issues that may cause significant fugitive emissions. To address this, Colorado requires operators to inspect a well "no later than 30 days after the facility commences operation."[192] We therefore recommend that EPA similarly require that the initial monitoring survey occur earlier so these problems can be addressed sooner and mitigate potentially large emissions that would otherwise go undetected for up to 90 days.

Require targeted follow up on all detections. Certain advanced screening technologies (i.e., those with lower detection thresholds) may be capable of pinpointing the emitting equipment or component, allowing for direct repair and potentially obviating the need for a site-wide OGI survey. For technologies that EPA determines are capable of pinpointing the emitting component, we urge EPA to require immediate repair without a site-wide OGI survey when results of periodic screening identify a specific component. For technologies that EPA determines are capable of pinpointing an emitting piece of equipment, we urge EPA to require an OGI survey of that piece of equipment to locate the leaking component. If during follow up, an operator determines detected emissions are the result of normal operations and permissible, thus not requiring repair, that should be documented and reported to EPA. For technologies that detect at the site-level, or in cases where a specific component or piece of equipment cannot be determined based on the screening results, EPA should require a site-wide OGI survey to pinpoint the source. This survey should also satisfy the operator's annual OGI requirement if it covers all fugitive emissions components at the site. Again, emissions resulting from normal operations that do not require repair should also be documented and reported.

Align repair requirements. EPA should require that all final repairs be completed within 30 days of detection or of receiving the results of a periodic screening. As described above regarding OGI, we believe that a 30-day total repair timeline (including any follow-up survey, first attempt, and final repair) is feasible and necessary to achieve the emissions reductions estimated by EPA. This timeline is feasible and already required by leading states.[193] In particular, results of aerial screenings are likely to indicate large emission events that should be quickly repaired. And to achieve the reductions anticipated by EPA through the equivalency modeling, regulatory repair timelines must align with modeling assumptions.

Align root cause analysis requirements. We support EPA's proposed root cause analysis requirements for when emissions are detected from control devices, covers, and closed vent systems. These types of emission events may be large (particularly unlit or malfunctioning flares) and likely indicate a deviation from the applicable standards. A root cause analysis is an appropriate response and should be conducted as soon as possible to return the site back to normal and compliant operations. We urge EPA to ensure these standards also apply when

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[192] 5 Colo. Code Regs. §1001-9-D-I.L.2.d. (2023).
[193] *See, e.g.*, Colo. Code Regs. § 1001-9-D-II.E.7; N.M. Code R. § 20.2.50.116(E) (2023).

emissions from control devices, covers, and close vent systems are detected through OGI or AVO surveys under the primary standards.

Ensure monitoring plans are uniform. While we support providing flexibility to operators, we urge EPA to ensure that applicable monitoring requirements are not so multifarious that it complicates compliance and enforcement efforts. We therefore urge EPA to require that similar sites (based on either site characteristics or locations) be grouped together and subject to the same monitoring plan and screening option. The fugitive monitoring plan should also include the number and type of all pieces of major production and processing equipment at each sites (including those relevant to the site's subcategorization), as well as the number of covers, closed vent systems, and control devices that are present at each site.

Align deployment and approval. EPA should clearly specify in the regulatory text that periodic screening must occur 1) using a technology approved under the process described in section 60.5398b(d), 2) at the frequencies listed in Tables 1 and 2, *and* 3) in accordance with the standard and approved operating protocols. In other words, EPA should clarify in section 60.5398b(b) that the technology has to be deployed using the same operating protocols and under similar conditions as EPA approved under section 60.5398b(d). Technologies may be capable of achieving different requirements in Tables 1 and 2 under differing conditions or when following certain operational protocols. EPA must ensure deployment in the field conforms to the parameters approved by EPA.

d. Continuous monitoring

We support EPA's proposal to allow continuous monitoring technologies as an alternative to periodic screening based on long- and short-term emissions rate thresholds that would trigger corrective action paired with monitoring plan requirements. EPA has proposed two action levels: a long-term action level (1.2-1.6 kg/hr based on rolling 90-day average) to limit emissions over time, and a short-term action level (15-21 kg/hr) to identify large leaks and malfunctions. Both would apply to all operators using continuous monitors and a root cause analysis and corrective action would be triggered when either action level is exceeded, requiring investigation and repairs within five days.

Given the broad variety of continuous monitoring systems and the multitude of factors that impact performance, EPA's approach is reasonably calculated to ensure equivalent emission reductions. We urge EPA to consider lowering the short-term action level threshold or otherwise shortening the duration of the long-term action level. We are concerned that the proposed framework could unnecessarily allow emissions to persist when they could be mitigated much sooner. EPA must also ensure sensor placement is adequate to detect emissions from all fugitive emissions components and any control devices, covers, or closed vent systems at the site. We are aware of situations where continuous monitors have missed significant emissions events at sites due to sensors being placed too low. Because of these concerns, we also urge EPA to require an OGI or AVO backstop at all sites opting for continuous monitoring consistent with our recommendations on the screening approaches.

Certain continuous monitoring technologies may fit within the periodic screening framework, such as tower-based systems. We therefore urge EPA to consider such technologies within that context during the alternative test method approval process. We also recognize that certain continuous monitoring systems may be highly effective but do not fit within the parameters set forth by EPA. We urge EPA to evaluate those technologies through the technology approval process and through AMEL applications.

e. *Alternative test method approval*

Prior to regulatory deployment, screening technologies and continuous monitoring technologies must be approved by EPA through a process that "will include consideration of the combination of the measurement technology and the standard protocol for its operation." As described above, both aspects are critical because the detection capability of a given technology can vary greatly depending on operating protocols and conditions. The alternative test method approval process must therefore assess technology performance under a wide variety of conditions representative of field conditions in diverse basins across the country. A technology should then be approved as meeting a specified detection threshold that it is capable of routinely and reliably achieving under a variety of conditions. We support EPA's proposed approval process and provide the following recommendations.

Eliminate conditional approval. EPA's failure to act on an application for alternative test method approval within 270 days cannot be the basis for conditional approval for regulatory deployment. EPA is obligated under section 111 to ensure any alternative methods achieve equal or greater reductions than would occur under the primary standard, in this case the fugitive monitoring requirements described at section 60.5397b. If EPA does not actually evaluate and approve a technology for periodic screening, there is no assurance that it will achieve the reductions estimated by EPA through the FEAST modeling. EPA is required to thoroughly vet and approve or disapprove any technology prior to use for regulatory compliance, and conditional approval does not satisfy this requirement. If EPA retains a conditional approval process, it must provide a mechanism for challenging the approval and must resolve any challenges prior to the technology being deployed for regulatory use.

Address basin- and site-specific requests through the AMEL process. Technologies approved through this process should be capable of performing nationwide in diverse basins and at a variety of site types. EPA should not spend time and resources to approve technologies that may only be suitable for very limited applications. Further, approving technologies for varying deployment in different basins or at different sites would require additional modeling to ensure equivalence. This would not be a good use of resources and would not align with the structure of section 111, which is uniform and national in scope. EPA should instead address any such requests through the AMEL process.

Enable public participation. EPA must enable broad stakeholder participation in the technology vetting and approval process. EPA should publish all application materials publicly and allow for public input throughout the process, including by accepting and considering information and studies from any stakeholder and not limiting review only to materials submitted by the technology provider or operator. The process should be transparent and there should be a mechanism for challenging final approval or disapproval decisions.

Define follow-up and repair requirements. If EPA decides to tier follow-up requirements based on the sensitivity of a technology (i.e., allowing immediate repair when technology can pinpoint emissions at the component- or equipment-level), it must ensure technologies can reliably isolate leaks at their claimed level under diverse conditions. EPA must then clearly define follow-up and repair requirements for a given technology and cannot leave broad discretion to operators to determine the appropriate follow-up action.

C. Super-Emitter Response Program

In addition to the other source-specific rules discussed in this section, EPA's proposed super-emitter response program (SERP) has potential to achieve significant reductions in methane emissions from the oil and gas industry. This program leverages widespread and growing use of advanced technologies by allowing certified entities to use approved technologies to identify very large emission events—i.e., events with emission rates of 100 kilograms per hour of methane (kg/hr) released. SERP requires that (1) the certified monitoring entity notify the responsible owner of the site responsible for the super-emitter event and (2) the responsible owner conduct a root cause analysis and, when appropriate, take corrective action to eliminate the emission event. EPA must also make information gathered and reported under the program publicly available. "The principal objective of this program is to provide a comprehensive and effective remedy for large emission events that disproportionately contribute to methane emissions from the [oil and gas industry] and can be accompanied by health-harming pollution that affects nearby communities."[194]

Super-emitting sources, which can be intermittent and difficult to predict, pose unique problems for methane mitigation efforts. Thus, there is significant need for standards and rules that specifically address these major emission events, and EPA has broad statutory authority to support its proposed super-emitter program. We urge EPA to finalize SERP with a streamlined process for determining and notifying the responsible operator so emissions are quickly addressed. EPA must also establish a notification framework to ensure information on these emissions events and the response action are publicly available and easily accessible in real time so that community members are updated while the events are occurring, not after the fact. We also recommend that EPA not create barriers to participation in SERP that exceed the requirements for operators under the LDAR program.

1. EPA properly proposes requirements to tackle super-emitter events.

Super-emitters are individual sources that emit huge amounts of methane and other pollution, typically as a result of malfunctions or abnormal processes.[195] These events contribute to the "heavy-tailed" distribution commonly observed across the oil and gas sector,[196] meaning that a small number of sources are responsible for a disproportionate share of total emissions from the industry.[197] As EPA explained in the supplemental proposal preamble, this often means that the

[194] 87 Fed. Reg. at 74748–52.
[195] *See, e.g.*, Zavala-Araiza, *Super-emitters*, *supra* note 131; 87 Fed. Reg. at 74746.
[196] *See, e.g.*, Yuanlei Chen et al., *Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey*, 56 Env't Sci. Tech. 4317, 4317-23 (2022), https://pubs.acs.org/doi/pdf/10.1021/acs.est.1c06458 [hereinafter "Chen et al., *Quantifying Methane Emissions in New Mexico Permian Basin*"].
[197] 2022 Joint Environmental Comments, *supra* note 1, at 63–68.

top 5-10% of sources contribute 50% or more of total emissions.[198] This phenomenon has been well documented in academic studies over the past decade, which we cited extensively in our comments on the initial proposal.[199]

New studies published in the year since EPA issued its initial proposal have only further solidified the problem posed by super-emitters, documenting the widespread existence of sources emitting at or well-above EPA's proposed super-emitter threshold of 100 kg/hr. A study by Chen et al. released in March 2022 found that just 118 out of 958 sources surveyed in the Permian Basin using an aerial monitoring program were responsible for 50% of total emissions from the region.[200] Another study released in July 2022 found that super-emitting sources were responsible for nearly 40% of total methane emissions between 2019 and 2021 across five major oil and gas basins: the San Joaquin Valley in California, the Uinta Basin in Utah, Denver-Julesburg Basin in Colorado, the Permian Basin in Texas and New Mexico, and the Marcellus Shale Basin in Pennsylvania.[201] The study included super-emitting sources from oil and gas production, wet manure from animal feedlots, large landfills, and coal mine venting, but found that oil and gas production sources made up the majority of super-emitters in almost every basin except the Marcellus Shale, which was more heavily influenced by coal mine venting.[202]

Recent measurement-based studies again confirm that total oil and gas emissions are much higher than official estimates.[203] This discrepancy is attributed to "low-probability but high-consequence sources [that] can contribute the majority of methane emissions from an oil and gas producing region" but that are not well characterized in official inventories.[204] These studies underscore that addressing super-emitters is centrally important in efforts to drive down total emissions.

Studies have also identified and quantified ultra-emitters.[205] These sources are responsible for some of the largest methane plumes ever observed. An international study released in July 2022

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[198] 87 Fed. Reg. at 74746.
[199] 2022 Joint Environmental Comments, *supra* note 1, at 23–24, 63–68, 98, 126–27, 200–01.
[200] Chen et al., *Quantifying Methane Emissions in New Mexico Permian Basin*, *supra* note 196.
[201] Daniel H. Cusworth et al., *Strong Methane Point Sources Contribute A Disproportionate Fraction of Total Emissions Across Multiple Basins in the United States*, 119 Proceedings of the Nat'l Acad. of Scis. 1, 1–4, 6 (2022), https://www.pnas.org/doi/10.1073/pnas.2202338119 [hereinafter "Cusworth et al., *Strong Methane Point Sources*"].
[202] *Id.* at 3–4.
[203] Sherwin et al., *supra* note 166 (combining Carbon Mapper and Kairos surveys with an expanded version of the emissions simulation tool from Rutherford et al. 2021 to "infer emissions inventories for six regions in the United States comprising 52% of onshore oil and 29% of gas production over fifteen aerial campaigns. Total estimated emissions range from 9.63% of natural gas production, roughly nine times the US government estimate, to 0.75% in a high-productivity gas-rich region."); William Kunkel et al., *Extension of Methane Emission Rate Distribution for Permian Basin Oil and Gas Production Infrastructure By Aerial LiDAR*, Earth ArXiv (2023) (preprint), https://eartharxiv.org/repository/view/4895/ (Carbon Mapper and Bridger measurements in the Permian at 7,920 oil and gas production facilities increase the total emission rate for the survey region by a factor of 3.0 after controlling for scale factors such as survey area and number of scans per facility); Matthew Johnson et al., *Creating Measurement-Based Oil and Gas Sector Methane Inventories Using Source-Resolved Aerial Surveys*, Rsch. Square (2022) (preprint), https://www.researchsquare.com/article/rs-2203868/v1.
[204] Sherwin et al., *supra* note 166, at 4.
[205] *See, e.g.*, Sudhanshu Pandley et al., *Satellite Observations Reveal Extreme Methane Leakage From A Natural Gas Well Blowout*, 116 Proc. Nat'l Acad. Sci. 2376, 26376–81 (2019),

used global satellite monitoring data to identify multiple ultra-emitters in the Permian Basin with emission rates ranging from 700 kg/hr up to a whopping 24,000 kg/hr.[206] NASA satellite monitoring data from the Earth Surface Mineral Dust Source Investigation mission has also identified at least one ultra-emitting facility in the Permian Basin with a recorded emissions rate of 18,300 kg/hr of methane released.[207]

Despite the significant contribution of these sources to overall methane pollution, these emission events can be difficult to capture through periodic monitoring programs because they tend to be intermittent and unpredictable.[208] Indeed, we explained in our comments on EPA's initial proposal that regular LDAR can fail to capture super-emitters, especially within the timeframe required for mitigation.[209] For instance, if a super-emitter source at a well site starts leaking after an inspection, it could continue to leak 100 kg/hr unabated for three months–the period of time between quarterly inspections. That would equate to over 17.5 million metric tons of CO_2-e, or the annual emissions of 5,400 passenger cars.[210]

But, as noted above, many sources emit well above even EPA's 100 kg/hr threshold. For example, a 2018 natural gas well blowout in Ohio was initially estimated to have a leak rate of 100 million cubic feet of natural gas per day—twice that of the Aliso Canyon leak. For the next twenty days, the well emitted an estimated 60,000 tons of methane.[211] From a climate standpoint, this amount is larger than some entire *countries'* annual emissions and is equivalent to the emissions of one million passenger vehicles driven for a year.[212] Moreover, super-emitters are widespread across the oil and gas sector, encompassing numerous sources scattered over broad geographic areas.[213] New studies from 2022 have identified large emission events at well sites, gas processing plants, compressor stations, storage tanks, and gathering pipelines.[214] As a result, there is a significant need for EPA's standards to address super-emitters.

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https://www.pnas.org/doi/10.1073/pnas.1908712116 [hereinafter "Pandley et al., *Satellite Observations of Well Blowout*"].

[206] Daniel J. Jacob, et al., *Quantifying Methane Emissions From the Global Scale Down to Point Sources Using Satellite Observations of Atmospheric Methane*, 22 Atmos. Chem. Phys. 9617, 9617–46 (2022), https://acp.copernicus.org/articles/22/9617/2022/acp-22-9617-2022.pdf.

[207] Nat'l Aeronautics & Space Admin. Jet Propulsion Lab., *Methane 'Super-Emitters' Mapped By NASA New Earth Space Mission* (Oct. 25, 2022), https://www.nasa.gov/feature/jpl/methane-super-emitters-mapped-by-nasa-s-new-earth-space-mission [hereinafter "NASA Jet Propulsion Lab, Methane Mapped By Earth Space Mission"].

[208] 2022 Joint Environmental Comments, *supra* note 1, at 63. S*ee also* Cusworth et al., *Strong Methane Point Sources*, *supra* note 201, at 5; 87 Fed. Reg. at 74747.

[209] *See, e.g.*, 2022 Joint Environmental Comments, *supra* note 1, at 68. S*ee also* Cusworth et al., *Strong Methane Point Sources*, *supra* note 201, at 6; 87 Fed. Reg. at 74747 (explaining that periodic LDAR can miss these emission events).

[210] 100 kilograms * 24 hrs = 2,400 kilograms * 90 days = 216,000 kilograms. Env't Def. Fund, *Understanding the Near- and Long-Term Impacts of Emissions*, https://www.edf.org/understanding-near-and-long-term-impacts-emissions?co2=11&ch4=60000&n2o=6&hfc_134a=0 (last visited Feb. 4, 2023) [hereinafter EDF Methane Calculator].

[211] Pandley et al., *Satellite Observations of Well Blowout*, *supra* note 205, at 26376, 26378–79.

[212] EDF Methane Calculator, *supra* note 210.

[213] 2022 Joint Environmental Comments*, supra* note 1, at 98, 126–27, 200.

[214] Chen et al., *Quantifying Methane Emissions in New Mexico Permian Basin*, *supra* note 196, at 4318, Figure 1(d); Jevan Yu et al., *Methane Emissions from Natural Gas Gathering Pipelines in the Permian Basin*, 9 Env't Sci. Tech. Lett. 969, 969–74 (2022), https://pubs.acs.org/doi/10.1021/acs.estlett.2c00380; *see also* Carbon Mapper, *Carbon Mapper Data Portal*,

There are a number of individuals and institutions that are already tracking super-emitters, so it is efficient and practical for EPA to develop approaches that can leverage these independent data sources to quickly mitigate huge emission events. As discussed above, scientists have been studying super-emitters for years and have gathered substantial amounts of data on the sources and locations of these emitters. Multiple organizations have also developed programs to identify super-emitters, collecting information on the location, facility type, and emission rates of these sources across the oil and gas industry.[215] For instance both Carbon Mapper and EDF's PermianMAP project provide interactive maps with the location and emission rate of methane emitting sources.[216] Satellites under development will also soon provide information on the location of super-emitter events. Even other federal and international agencies have been collecting data on super-emitters, including NASA's Jet Propulsion Lab and the United Nations Environment Programme's Methane Alert and Response (MARS) program.[217] States are also beginning to conduct monitoring for super-emitters. California plans to deploy satellites, starting with two launches this year, to monitor for plumes of carbon dioxide and methane across the state.[218]

Utilizing this kind of independent monitoring information to identify major emission events and help to ensure action to eliminate them also makes sense from a practical standpoint. As the industry faces increasing scrutiny for its emissions, owners and operators will have bigger incentives to avoid detecting and disclosing large emissions.[219] Independent, third-party monitoring data can help to build confidence that efforts to reduce emissions are working. These data can be an important addition to the current industry self-reporting systems, under which numerous studies show that actual emissions are far higher than official estimates and do not align with operators' stated actions and goals.[220]

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https://data.carbonmapper.org/map#b=Mapbox_Satellite_Retina&l=AVIRIS_SOURCES_CLUSTER_MAP(1),AVIRIS(1),MITIGATION_EXAMPLES(1),AVIRIS_SOURCES_CLUSTER(1)&vm=2D&ve=-123.941240,31.444673,-91.641435,45.657885&pl=false&pb=false&tr=true&d=2023-02-01&tlr=days, (last visited Feb. 4, 2023) [hereinafter "Carbon Mapper, *Data Portal*"]; Env't Def. Fund, *Permian Methane Analysis Project (MAP): Equipment Emissions,* https://data.permianmap.org/pages/operators (last visited Feb. 4, 2023) (identifying major emission events at flares) [hereinafter EDF, *Permian (MAP)*"]; 87 Fed. Reg. at 74748 (stating that the most widely known sources of super-emitter events are controlled tank batteries, flares, natural-gas driven pneumatic controllers, and fugitive emission components).

[215] *See, e.g.*, Benjamin Hmiel et al., *Empirical Quantification of Methane Emission Intensity From Oil and Gas Producers in the Permian Basin*, 18 Env't Rsch. Letters 024, 029 (2023), https://iopscience.iop.org/article/10.1088/1748-9326/acb27e [hereinafter "Hmiel et al., *Empirical Quantification of Producers in the Permian Basin*"].

[216] Carbon Mapper, *Data Portal*, *supra* note 214; EDF, *Permian (MAP)*, *supra* note 214.

[217] *See, e.g.*, NASA Jet Propulsion Lab, Methane Mapped By Earth Space Mission, *supra* note 207; United Nations Env't Programme, *Methane Alert and Response System (MARS),* https://www.unep.org/explore-topics/energy/what-we-do/methane/imeo-action/methane-alert-and-response-system-mars (last visited Feb. 4, 2023). S*ee also* Carbon Mapper, *Resources,* https://carbonmapper.org/resources/, (last visited Feb. 4, 2023) (listing related methane monitoring programs).

[218] Cal. Air Res. Bd., *California Satellite Partnership*, https://ww2.arb.ca.gov/our-work/programs/california-satellite-partnership (last visited Feb. 6, 2023).

[219] Cynthia Giles, Part 4: Preventing Widespread Violations that Threaten Climate Goals at 47, in Next Generation Compliance: Environmental Regulation for the Modern Era (2021).

[220] *See, e.g.*, Env't Def. Fund, *PermianMAP Final Report: A Look Back at Key Findings and Takeaways From the Permian Methane Analysis Project* (2021)

These types of independent checks and mandatory reporting and corrective action programs like SERP are well established and consistent with past EPA practice. For example, EPA, along with the U.S. Coast Guard, administers the National Response Center program, which houses a reporting hotline that allows members of the public to report spills and discharges of oil and other dangerous and hazardous material.[221] Reports to the hotline can trigger obligations on the part of EPA, the Coast Guard, and other federal agencies, as well as responsible facilities, to investigate and, where necessary or appropriate, take action to clean-up and mitigate the spill or discharge in accordance with the National Contingency Plan.[222] EPA also issued fenceline monitoring standards for petroleum refineries in 2015 that require refineries to set up systems around refinery fencelines to monitor for benzene as an indicator pollutant for other hazardous pollutants.[223] If monitoring shows that benzene levels exceed a certain threshold, the refineries are then required to conduct a root cause analysis and take corrective action.[224] Refineries also must report their fenceline monitoring data to EPA, which makes the data publicly available on its Enforcement and Compliance History Online (ECHO) site.[225] Other federal agencies have also developed similar third-party programs to assess compliance with a wide variety of regulations, from food safety and labeling to energy and water efficiency standards.[226]

SERP, as well as the EPA programs noted above, all build on the longstanding and well-established role that independent parties have played in reporting potential violations of Clean Air Act standards to EPA. "Reports from the public have led to state and federal enforcement cases and ultimately served environmental protection well."[227] To that end, EPA has long "invite[d]" independent third parties to assist the agency in carrying out its environmental protection duties under the Act "by identifying and reporting environmental violations" via its

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https://blogs.edf.org/energyexchange/files/2022/11/PermianMAPFinalReport.pdf (finding that numerous operators had methane intensities that far exceeded their stated targets). *See also* Hmiel et al., *Empirical Quantification of Producers in the Permian Basin*, *supra* note 215 (using data gathered during aerial observations to calculate individual operator methane intensities).

[221] U.S. Env't Prot. Agency, *National Oil and Hazardous Substances Pollution Contingency Plan (NCP) Overview* (last updated Mar. 25, 2022), https://www.epa.gov/emergency-response/national-oil-and-hazardous-substances-pollution-contingency-plan-ncp-overview [hereinafter "EPA NCP Overview"]. *See also* 87 Fed. Reg. at 74749.

[222] *Id.; See also* 40 C.F.R., pt. 300, subparts D & E; *id.* § 300.185 (providing for non-governmental participation in response efforts).

[223] 40 C.F.R. § 63.658; 87 Fed. Reg. at 74748 (citing 79 Fed. Reg. 36880, 36920 (Jun. 30, 2014)).

[224] 40 C.F.R. § 63.658.

[225] U.S. Env't Prot. Agency, *EPA Launches New Online Tools to Provide Communities With Information on Environmental Enforcement and Compliance* (Oct. 2, 2022), https://www.epa.gov/newsreleases/epa-launches-new-online-tools-provide-communities-information-environmental; *see also* 2022 Joint Environmental Comments, *supra* note 1, at 136–37 (noting that EPA issued Compliance Assurance Monitoring and Credible Evidence Revisions rulemakings which allow EPA and the public to use non-reference test data for compliance monitoring and enforcement rules and require compliance assurance monitoring at major sources and corrective action when an exceedance is detected to return the facility to normal operations).

[226] Administrative Conference of the United States: Adoption of Recommendations, 78 Fed. Reg. 2939, 2941 (Jan. 15, 2013) (setting forth recommendations for agencies to consider when developing third-party compliance assessment programs); Lesley K. McAllister, University of San Diego School of Law, *Third-Party Programs to Assess Regulatory Compliance,* at 9, Table 1 (2012), https://www.acus.gov/sites/default/files/documents/Third-Party-Programs-Report_Final.pdf (summarizing information about eight different third-party compliance assessment programs across a number of federal agencies).

[227] U.S. Env't Prot. Agency, *Report an Environmental Violation, General Information* (last updated July 5, 2022), https://www.epa.gov/enforcement/report-environmental-violation-general-information.

online Report an Environmental Violation webpage or by contacting relevant regional staff.[228] EPA's online reporting tool is housed in the agency's ECHO database, which includes EPA, state, local, and tribal compliance and enforcement records that are reported to EPA national databases.[229]

2. SERP is grounded in EPA's Clean Air Act authority.

Because super-emitters disproportionately contribute to total emissions and have a significant impact on the communities where they are located, EPA has explained that the SERP program is necessary to "backstop compliance and address the unique characteristics of these events."[230] EPA, thus provides two separate statutory bases to support the program.

First, EPA proposes that super-emitter emission events are separate and distinct affected and designated facilities, with SERP serving as the "best system of emission reduction" for these sources. Under this proposal, a super-emitter affected or designated facility is defined as "any equipment or control device . . . at a well site, centralized production facility, compressor station, or natural gas processing plant" that causes a release with a quantified emission rate of 100 kg/hr of methane or more.[231] Given that these events occur as result of malfunctions or abnormal operations, the BSER for these events would be corrective action to address the malfunction or abnormal operation that caused the emission event in order to resume normal operation, in accordance with the program parameters set out by EPA.

Second, EPA explains that SERP is justified as a backstop to ensure compliance with the other standards and requirements included in the rules that apply to affected and designated facilities, a number of which are known sources of super-emitter emission events. EPA proposes to incorporate the program as an additional compliance assurance measure for sources that are subject to numeric standards of performance and control device requirements and as an additional work practice standard for sources subject to that type of standard in the rules. For sources that are subject only to work practice standards, like a collection of fugitive emission components, EPA proposes that the BSER for those sources includes targeted root cause analysis and corrective action for super emitter events. Again, as noted above, if a source subject to a numeric, control device, or work practice standard has a super-emitter event, it is very likely that the source would be out of compliance with the applicable standard and the source would already have to take corrective action to come back into compliance with the applicable standard.

EPA's proposed super-emitter threshold of 100 kg/hr of methane released also aligns with the agency's stated bases for SERP as a backstop program. This threshold level helps ensure that the program would not capture permissible emission events and that SERP would not be duplicative of other standards or requirements in the rules, like the LDAR program. Rather, SERP would achieve emission reductions by assuring compliance with those rules. Moreover, the high emission threshold ensures that the program is administrable, as it will help avoid an influx of

[228] *Id.*; U.S. Env't Prot. Agency, *ECHO: Report Environmental Violations* (last updated Sept. 21, 2022), https://echo.epa.gov/report-environmental-violations.
[229] U.S. Env't Prot. Agency, *Enforcement and Compliance History Online: About the Data* (last updated Dec. 14, 2022), https://echo.epa.gov/resources/echo-data/about-the-data.
[230] 87 Fed. Reg. at 74747.
[231] *Id.* at 74752.

monitoring reports identifying smaller emission events that may be permissible. As we and EPA have noted, there are permissible emission events at lower levels, like emissions from an uncontrolled tank, that would not necessarily be an impermissible emission event.[232]

Additionally, there should be little to no cost associated with the program. Owners and operators should already be addressing malfunctions and poor operating conditions as part of their normal operations, so the costs of SERP would already be accounted for in a facility's operational costs and the costs of complying with the underlying standards. A super-emitter event would indicate likely noncompliance with standards for the underlying source—including a source-specific limit or work practice—so operators would already be required to come back into compliance with the source-specific standard. In any event, if there are additional costs associated with investigating and addressing super-emitter events, those costs would be minor and highly justified in relation to the benefits gained by stopping these huge emission events, making any associated costs "obviously cost-effective."[233]

In addition to EPA's proposed statutory bases for SERP, Clean Air Act sections 113 and 114 provide legal authority for the program, as we explained in our comments on EPA's initial proposal.[234] Section 114 gives EPA broad information-gathering authority to develop standards and emissions guidelines under section 111 and to determine whether a facility is out of compliance with a section 111 standard or guideline.[235] It also permits EPA to require persons with relevant information to provide that information to the agency, set parameters for monitoring methods, and make publicly available any information gathered.[236] Section 113, in turn, allows EPA to engage in an enforcement action based on "any available information" that shows a facility has violated a standard or requirement under the Act.[237] These Clean Air Act authorities further support the SERP program.

EPA's focus on compliance assurance fits particularly well with the goals of the program and with the problem of super-emitters. Emission events exceeding 100 kg/hr indicate major problems at the site resulting from either non-compliance or serious operational issues. As we outlined in our initial comments, EPA has broad authority under section 114 to accept and use third-party monitoring data for purposes related to section 111, including ensuring compliance. Importantly, SERP does not and should not replace obligations on the part of owners and operators to reduce methane emissions from affected and designated facilities under the rules. Rather, SERP would serve as an additional backstop to ensure the unique problems posed by super-emitters are timely addressed.

3. Program structure & recommendations

We support EPA's proposed structure for SERP, which we believe is reasonably tailored to achieve the program's objectives and provides sufficient guardrails to ensure data is rigorous and actionable. This type of program has significant potential to help further drive down emissions

232 *Id.* at 74749; 2022 Joint Environmental Comments, *supra* note 1, at 63, 139.
233 87 Fed. Reg. at 74752–55.
234 2022 Joint Environmental Comments, *supra* note 1, at 135–37
235 *Id.* at 135.
236 *Id.* at 135, 137.
237 *Id.* at 135, 139.

from super-emitters by incorporating independent monitoring data gathered in the field using scientifically rigorous methods and making that data actionable for operators. We agree with EPA that events of this magnitude should generally not occur at a site that is well operated, well maintained, and that has implemented EPA's proposed standards. Independent third-party monitoring data showing such emission events will therefore likely indicate major problems, regulatory violations, and events that endanger nearby communities. This type of program may also serve as a valuable preventative measure, creating additional incentives for operators to keep their sites maintained and properly operated so such events do not occur. And perhaps most importantly, publication of these emission events will allow nearby community groups to take appropriate protective action. It will also build trust in the entire enterprise of driving down methane emissions, which currently is lacking due to the large discrepancy between reported emissions and stated actions and the frequent large emissions typically uncovered in field observations.

Below we discuss six components of the program and our recommendations for each. These include a) the emissions threshold, b) the technologies that may be used, c) the qualifications for third-party notifiers, d) the requirements for a valid detection, e) the data publication and notification process, and f) the operator response requirements.

a. 100 kg/hr emissions threshold

The use of a 100 kg/hr threshold for this program is appropriate for the reasons described above relating to the underlying legal justification and also based on a host of scientific, technical, and practical considerations. Most importantly, this threshold properly focuses resources on the largest and most harmful emission events, prioritizing their quick mitigation and repair. Emissions of this magnitude could release thousands of tons of methane in a matter of days or weeks. In the absence of SERP, these emissions might go undetected for up to six months or more (the length of time between semiannual LDAR inspections). A persistent event of this duration would release over 400,000 kilograms of methane, an amount having the same climate impact as 3,400 homes' annual energy usage.[238] In addition, such emission events should not be occurring at a properly designed and operated site, and therefore will likely indicate abnormal processes and equipment failures that are violations of the underlying regulatory requirements.

EDF's PermianMAP project, which consisted of numerous flyovers in the Permian Basin spanning multiple years, found a significant number of emission events exceeding 100 kg/hr from a wide range of operators. Many events of this magnitude resulted from unlit flares, failures on tank control systems, and gathering line malfunctions. Unlit flares and failed tank controls are both violations of the proposed standards for those affected facilities.[239] Other studies have frequently found that emission events above 100 kg/hr make up a large fraction of total emissions even if they are generated by a small number of sites. For example, Zavala-Araiza et al. (2017) found that 20% of emissions were from sites with emission rates above 100 kg/hr. Researchers in the Permian have found 30-50% of emissions were due to sources with emission

[238] EDF Methane Calculator, *supra* note 210.
[239] Additional information, including operator and geographic location, are available publicly on PermianMAP.org.

rates greater than 100 kg/hr.[240] And Cusworth et al. (2021) found that 44 out of 1000 sites observed had emission rates greater than 100 kg/hr, with some as high as 5,000 kg/hr.[241]

The scientifically-backed 100 kg/hr threshold therefore appropriately captures the largest events likely to be violations of underlying standards while excluding many smaller permissible emissions, like certain vents and maintenance activities. The threshold also aligns well with the capabilities of currently available screening technologies, some of which require multiple passes before being able to quantify emissions. To address concerns about false detections of permissible maintenance events, EPA should require operators to report planned maintenance that could exceed 100 kg/hr and this information should be made publicly available. We also urge EPA to consider a secondary threshold of 1000 kg/hr that would entail heightened response action.

b. Permissible technologies

We support EPA's proposed technological parameters and the requirement that technologies be capable of quantifying an emission flux of 100 kg/hr or greater. However, we urge EPA to not overly restrict the technologies that may qualify. EPA should use the alternative test method approval process already under development to approve technologies for use in SERP. To do this, EPA would need to add an additional quantification criterion for SERP technologies, but otherwise may rely on the same procedures. We generally believe the technologies EPA has specified for SERP in the supplemental proposal are appropriate, but there may be additional technologies that could operate within the requirements of this program that are excluded by including a limited list. For example, tower-based systems that can quantify emissions, if approved by EPA, should also be allowable under SERP.

We urge EPA to not impose more onerous requirements on technologies used for SERP than those used under the LDAR program, aside from the quantification requirement. Qualified third parties should not face a higher barrier to monitoring than operators themselves do, especially because third party data will be more objective and potentially more accurate than data submitted by operators who may face conflicts of interest in accurately reporting their own emissions and violations. And with a 100 kg/hr detection requirement, there is no need for permissible technologies to be vetted in more depth than technologies deployed for the LDAR program which must be able to detect much smaller emissions sources.

c. Qualifications for independent third-party notifiers

We support EPA's proposed pre-qualification requirements for independent third-party notifiers, which we believe are central to the effectiveness of the program and ensuring safety and data veracity. These qualifications would include technical expertise in the specific technologies, the detection methodologies, and the necessary interpretation and analysis of the data collected. We believe these criteria are appropriate and urge EPA to not create overly restrictive standards that would unnecessarily limit participation. We also note that requirements for third-party notifiers

[240] Stokes, et al., *An aerial field trial of methane detection technologies at oil and gas production sites*, Chem Rxiv (2022), https://chemrxiv.org/engage/chemrxiv/article-details/625f27d2742e9f9470644f24.
[241] *See also infra* Section IV.C.1.

should generally align with and not be more restrictive than requirements for deploying advanced technologies in the LDAR program.

We also note that EPA inherently retains control over the entire program. If certain notifiers are repeatedly submitting data that do not include all six of the elements proposed by EPA, that data would simply not require the operator to take action. Independent parties with the technical expertise necessary to collect this type of data and meeting EPA's certification requirements should not face decertification for minor technical errors in submissions.

d. Valid detections

We largely support EPA's proposed six criteria for valid detections that would then trigger a response requirement for the responsible operator. We also agree that these upfront criteria, paired with the technology and independent third-party notifier approval process, obviate the need for additional data review by EPA after detection and support direct publication and notification to operators.

As proposed, each notification must include: (1) The location of emissions in latitude and longitude coordinates, (2) description of the detection technology and sampling protocols used to identify the emissions, (3) documentation depicting the emissions and the site (e.g., aerial imaging with emissions plume depicted), (4) quantified emissions rate, (5) date(s) and time(s) of detection and confirmation after data analysis that a super-emitter emissions event was present, and (6) a signed certification that the notifier is an EPA-approved entity for providing the notification, and the information was collected and interpreted as described in the notification.[242] These criteria are generally appropriate; however, we suggest a few modifications. The second criteria should typically be boilerplate and could be developed by EPA during the third-party notifier approval process. Only when a notifier is deploying multiple technologies or methods would this need to change. We also recommend that the fifth criteria be removed, and the date and time requirements be instead included in the first criteria alongside geographic coordinates. We believe the latter portion of the fifth criteria is unnecessary and is already encompassed in criteria one and four. In addition, we support the signed certification requirement and urge EPA to make similar requirements applicable to operators when submitting information about their response to the notification.

Importantly, as part of the standards applicable to well sites, centralized production facilities, and compressor stations, EPA should require operators to submit exact geographic locations of sites in their initial and annual reports. EPA has already proposed to require this information in the alternative LDAR standards at section 60.5398b, and should make similar requirements uniformly applicable. This information should then be used to accurately identify operators and sites responsible for detected emission events.[243] Using operator-submitted geographic information, EPA could design a portal for submission of notifications that would directly match the submission with the responsible operator.

[242] 87 Fed. Reg. 74750.
[243] *See* Hmiel et al., *Empirical Quantification of Producers in the Permian Basin, supra* note 215 (describing the process of matching aerial observations to sites and operators using Enverus Prism and GIS data).

We also recognize potential concerns about intermittency, wherein the detected emissions may not be present when the operator responds and visits the site. While emission events of this magnitude could be intermittent, they will generally indicate an underlying operational or design flaw at the site and should therefore be immediately investigated. Further, many may be persistent major malfunctions like unlit flares that should be immediately addressed. We also note that the LDAR standards do not require multiple detections before follow-up, and adding this requirement in SERP would also be inappropriate. Because events exceeding 100 kg/hr are extremely harmful, a single detection and quantification is sufficient to trigger a response and multiple observations should not be required. Many available technologies already require multiple passes before quantification is possible as well. If there are repeat detections at the same site, the operator should face heightened response requirements.

e. Operator response & data publication

EPA's proposed response measures for operators, which include a root cause analysis and corrective action, are appropriate due to the common causes of super-emitter events and the need to quickly mitigate such events to drive down emissions. Super-emitter events of this magnitude, as described above, will often be caused by unlit flares and tank malfunctions. In these situations, operators should be able to fix the underlying issue quickly, but may have to implement equipment, design, or operational changes to prevent recurrence. In situations where the emissions result from a permissible emissions event, maintenance activity, or are not from an affected source, operators should be able to easily make that determination based on their own records, and could submit that information in response. There may also be situations in which the emissions are intermittent and no longer present when the operator surveys they site. In this instance, a certification from the operator that emissions were not present should satisfy their response obligation. However, if there are repeat detections at the same site or a detection of very large emissions (over 1000kg/hr), there should be heightened response requirements.

We support EPA's proposed 5-day initiation and 10-day completion timeframe, and urge EPA to consider a shorter initial response requirement given the seriousness of emissions exceeding 100 kg/hr. When equipment, design, or operational changes would be required to prevent recurrence based on the root cause analysis, we believe EPA's proposal to require submission of a written report with a corrective action plan and information about completion of that plan within 30 days provides appropriate flexibility to operators in addressing more complex issues. The plan should include information about site design, deviations from applicable underlying standards, potential causes of the emission events, and the steps necessary to prevent recurrence. This information should be publicly available and should be sent to state regulators as well so that nearby communities have multiple channels for access.

All of this information, including the initial detection, initial operator response, repairs, corrective action planning and completion, and the final written report should be publicly-available in real time so that nearby communities and other stakeholders can stay informed and take protective action while emissions are occurring. Further, publicizing the operator's responsive actions can help build trust in the process and between communities and operators by demonstrating that responsible and quick action was taken. The initial detection submitted by the third-party notifier should be immediately available as soon as it is submitted to the operator and EPA. Communities must know about emissions of this size occurring in their vicinity.

Publicizing this information is consistent with EPA's past practices around emissions data and with the requirements of the Clean Air Act, which ensure emissions data are not treated as confidential.[244] Further, given that these emissions will be detected by third parties, it would be difficult or impossible for those data to not be publicized, as those entities could publish it on their own websites. To avoid inconsistent treatment of this information, EPA should make it all publicly available in real time on a single, centralized website.

The website should also include geographic and operator information, as well as links to the corrective action plan and other relevant follow-up information.[245] A centralized database with geographic coordinates and ownership information can streamline and ensure detections are accurately attributed to the correct site and operator. EPA should also centrally maintain information including the site type (e.g., fugitive monitoring subcategory), geographic location, responsible owner or operator, as well as other relevant records (e.g., fugitive monitoring plan and scheduled maintenance events), so that investigations after third-party notifications are efficient.

D. Pneumatic Controllers

In this supplemental rulemaking, EPA retains its proposal for a zero-emission standard for both new and existing pneumatic controllers with an exemption for sites in Alaska without electricity. EPA has also made two changes to the pneumatic controller affected facility definition. First, EPA is now defining the affected facility as the collection of all natural gas-driven pneumatic controllers at a site. Second, EPA is now including in the affected facility definition natural gas-driven controllers that route emissions for other purposes and self-contained natural gas-driven controllers. EPA also clarifies the meaning of "modification" and "reconstruction" under the Clean Air Act given adjustments to the affected facility definition, and proposes an exemption from the affected facility definition for emergency shutdown devices (ESDs).

The Joint Environmental Commenters strongly support EPA's proposed standards for pneumatic controllers. The standards acknowledge the variety of cost-effective zero-emitting technologies that are available to operators and give operators more than sufficient time to retrofit existing sites. EPA has previously required zero-emission technologies to mitigate air quality impacts[246] (including some pneumatic devices),[247] operators are choosing to transition to these technologies themselves, and leading U.S. states and Canadian provinces require similar standards to those proposed by EPA – all demonstrating the accessibility and availability of zero-emitting

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[244] 42 U.S.C. § 7414(c).
[245] See, e.g., *Permian Methane Analysis Project*, https://data.permianmap.org/pages/operators; *Carbon Mapper Data Portal*, https://carbonmapper.org/data/.
[246] A 1984 set of Section 111(h) design standards for volatile-organic-compound emissions at petroleum refineries required the use of "closed-purge sampling connection systems" that "eliminate emissions." 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. 22598 (May 30, 1984) (finalizing closed-purge requirement).
[247] Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources, 81 Fed. Reg. 35824, 35844 (Jun. 3, 2016).

technologies and the feasibility of these standards across the sector.[248] We incorporate by reference our support for the zero-emission standard from our previous comment[249] and outline further justification for the proposal below.

1. EPA's proposed pneumatic controller standard will reduce emissions as much as practicable.

Under section 111, EPA must analyze the emissions reductions that could be achieved under various systems and pick "the best system" that is adequately demonstrated after considering several variables, including whether the system will "reduc[e]emissions as much as practicable."[250] EPA's standard for pneumatic controllers would reduce emissions as much as practicable by requiring operators to use widely available technologies designed to emit zero emissions, including grid-connected, solar, instrument air, routed, or self-contained controllers.

Emissions data also demonstrates EPA will reduce emissions as much as practicable. Pneumatic controllers are a significant source of methane emissions, having contributed 2,225,347 metric tons of emissions to the atmosphere in 2019, and representing 45 percent of total methane emissions estimated from all petroleum systems and 22 percent of all methane emissions from natural gas systems according to EPA's estimates.[251] The three tables below summarize 2019 emissions from pneumatic controllers as represented in the 2021 GHGI.[252]

Table 11: Emissions from Pneumatic Controllers by Segment and Type of Controller

Emissions Estimates (in metric tons) and Equipment Counts		Type of Controller			
		Low Bleed	Intermittent Bleed	High Bleed	Total
Production Segment – Well Pads[1]	mt Methane (%)	433,674 (22%)	1,416,064 (73%)	91,034 (5%)	1,940,772
	# of Controllers (%)	421,043 (28%)	1,064,710 (70%)	28,448 (2%)	1,514,201
	mt Methane (%)	39,258 (21%)	135,972 (71%)	15,002 (8%)	190,232

[248] British Columbia, CA requires all new pneumatic controllers and pumps to be zero-bleed and requires retrofit of existing controllers at all large compressor stations to eliminate emissions by 2022. *See* B.C. Reg. 282/2010 § 52.05(2), (3), https://www.bclaws.gov.bc.ca/civix/document/id/crbc/crbc/282_2010. Colorado has prohibited use of venting gas-driven controllers at new sites. New Mexico prohibits use of gas-driven controllers at new sites and requires a phase-out of existing gas-driven controllers. (*See* N.M. Code R. § 20.2.50.122 (2023)). Jan Gorski et al., *Reducing methane emissions from Canada's oil and gas sector* 11 (2022), https://www.pembina.org/reports/engo-comments-methane-discussion-paper-2022-05.pdf; *See Canadian Capabilities in Methane Emissions Reduction: Guide and Company Directory for the Oil and Gas Sector* 10–11, https://www.ptac.org/wp-content/uploads/2021/02/Canadian-Methane-Emission-Reduction-Guide-and-Directory-PTAC-1.pdf (presenting case studies showcasing the feasibility of transitioning to electrically-powered pneumatic devices); *see also* Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64662 (2015), https://www.govinfo.gov/content/pkg/FR-2015-10-23/pdf/2015-22842.pdf.

[249] *See* 2022 Joint Environmental Comments, *supra* note 1.

[250] *Sierra Club v. Costle*, 657 F.2d 298, 326 (D.C. Cir. 1981).

[251] 87 Fed. Reg. at 74765.

[252] Emissions figures were calculated using activity data from the 2021 GHGI (Annexes 3.5 and 3.6) and the recently updated GHGRP subpart W emissions factors for pneumatic controllers.

Production Segment - Gathering and Boosting Stations	# of Controllers (%)	38,114 (26%)	102,235 (71%)	4,688 (3%)	145,037
Transmission and Storage Segment	mt Methane (%)	7,399 (8%)	31,996 (34%)	54,948 (58%)	94,343
	# of Controllers (%)	6,434 (7%)	82,040 (83%)	10,027 (10%)	98,501
Total	Methane Emissions				2,225,347

Table 12: Emissions from Pneumatic Controllers by Oil and Gas Industry Segment

	CH4 Emissions (kt)
Gas Production Segment – Well Pads	1,152.2
Gas Production Segment – Gathering and Boosting	190.2
Gas Transmission and Storage Segments	94.3
Gas Processing Segment	2.1
Oil Production Segment	788.5

Table 13: 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	215,061	218,613	39,258	4,699	2,699	480,330
High Bleed Controllers	54,592	36,442	15,002	21,971	32,981	160,988
Intermittent Bleed Controllers	882,569	533,496	135,972	25,419	6,577	1,584,033
All Controllers	1,152,222	788,551	190,232	52,089	42,257	2,225,351

Table 14: Emissions reductions from pneumatic devices, 12-year period (metric tons Ch4)[253]

[253] To estimate emissions reductions from the 2016 proposal, we used the 2016 RIA Table 3-4. U.S. Env't Protection Agency, Regulatory Impact Analysis of the Final Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources (2016), https://www.regulations.gov/document/EPA-HQ-OAR-2010-0505-7630. We took the average of projected emissions reductions in 2020 and in 2025, then multiplied this number over a 12 year period. To estimate emissions reductions for the 2021 proposal, we used Table 2-11 of the 2021 RIA and converted from short tons to metric tons. To estimate emissions reductions for the 2022 Proposal, we used Table 5-5 of the RIA, and converted from metric tons of CO2e to metric tons methane using a GWP of 25. The latter two equations from EPA spanned a 12-year period.

	2016 Proposal	2021 Proposal	2022 Proposal
Pneumatic Pumps	212,280	879,969	N/A
Pneumatic Controllers	21,768	17,236,510	N/A
Total Pneumatic Devices	234,048	18,116,479	21,600,000

EPA's proposal is expected to reduce emissions from pneumatic devices by 2 million metric tons per year once fully in effect, totaling 21.6 million metric tons over a 12-year period (or from 2023-2035). Table 14 compares expected emissions reductions from this rule to the 2021 proposal and 2016 regulations over that 12-year period.

This data illustrates the significance of emissions from this sector, the emissions reductions that will be achieved, and that EPA's proposal will reduce emissions as much as practicable.

2. EPA's proposed pneumatic controller standard is cost-effective and feasible.

EPA updated its cost analysis and continues to find that the zero-emitting controller standard is cost-effective overall. Specifically, it finds in the production segment that grid-connected, solar, and compressed air controllers are cost-effective at small sites ($81/ton, $119/ton, and $984/ton, respectively), medium sites ($48/ton, $84/ton, and $531/ton, respectively), and large sites ($31/ton, $65/ton, and $297/ton, respectively) (using a multipollutant approach), all of which are reasonable and below EPA's $1,970/ton benchmark for this proposal and the $2,185/ton benchmark used in previous rules.[254] EPA also finds cost-effectiveness for these technologies across model plants in the transmission and storage segments (except for instrument air at some sites).[255]

In this section, we explain our support for EPA's improved cost analysis and cost-effectiveness determination and make recommendations for further improvements, illustrate how EPA's standard is cost-effective in a range of circumstances, and summarize a new independent analysis that concurs with and bolsters EPA's conclusions by demonstrating cost-effectiveness by U.S. region.

a. EPA's updated cost analysis is more robust and we strongly support its cost-effectiveness determination.

EPA updated its cost analysis from the November 2021 proposal, making it even more robust and defensible overall. We explain our support for the updates and make recommendations for further improvements below.

[254] 87 Fed. Reg. at 74718.
[255] *Id.*

EPA incorporated a number of changes to its cost analysis that are warranted by the underlying record evidence.[256]

For instance, it is now properly accounting for annual maintenance costs of both natural gas pneumatic systems and electric/instrument air systems in accordance with the Carbon Limits cost model.[257] For natural gas pneumatic systems, it averages maintenance costs of systems with wet and dry gas.[258] For zero-emitting systems, it accounts for annual maintenance of electric controllers, periodic replacement of solar panels and batteries (for solar-powered sites), and the cost of grid electricity (for grid-powered sites). With these updates, switching away from gas-driven pneumatic controller systems to electric and solar systems results in net maintenance cost savings for operators, and lowers net maintenance costs for instrument air systems.[259]

EPA also adjusted its cost analysis to distinguish new sites from existing sites in a few ways. First, capital costs for new sites will now include net costs to "represent the difference in the capital cost between the pneumatic controller system not driven by natural gas and the natural gas-driven controllers that would be used in the absence of a zero-emissions requirement."[260] We support this update. Previously, EPA inaccurately assumed that capital costs would be the same for both new and existing sites, when new sites must consider net capital costs. Second, EPA updated its analysis so that model plants for new sources exclude high-bleed controllers, reasoning that some state regulations and NSPS OOOOa do not allow the installation of high-bleed controllers at new sites.[261] We support this change because EPA previously included high-bleed controllers in its model plants when, in fact, EPA should assume that all new continuous bleed controllers are low-bleed, as required by NSPS OOOOa and some state regulations. Third, EPA correctly adjusted its electric controller capital costs for existing sites to account for the fact that sites may be able to reuse existing valves for these sources.[262] And fourth, EPA states that "for instrument air systems, the new site costs now include costs for the new controllers, while the assumption for existing sources is that they can continue to use the existing controllers that were formerly driven by natural gas."[263] (However, we note that in calculating net capital costs, EPA appropriately subtracts out costs of controllers for a new site, because they would be needed for both natural gas-driven and instrument air systems).

Additionally, EPA updated the emission factors so that they are now consistent with recent proposed GHGRP updates. We support EPA using different emission factors for the production and transmission and storage segments and aligning with proposed GHGRP updates, and think its proposed emission factors for the production and gathering and boosting segments are an improvement. However, as some groups here noted in comments to the GHGRP update proposal,

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[256] *See* 2022 Joint Environmental Comments, *supra* note 1, at 138–52.
[257] *See* Malavika Venugopal & Stephanie Saunier, Carbon Limits, *Memorandum: Updated applicability and cost effectiveness for zero emission pneumatic controllers* (Jan. 2023) [hereinafter Carbon Limits, 2023 Memo] (included as Attachment L).
[258] 87 Fed. Reg. at 74761.
[259] *Id.*
[260] *Id.*
[261] *Id.*
[262] *Id.* at 74767.
[263] *Id*.

we think EPA can further improve its emission factors for the production and gathering and boosting segments.[264] Specifically, we noted that EPA should not base its emission factors on studies that measured emissions for 15 minutes (or less), because these measurements have a greater potential for error than studies that utilize longer measurement periods.[265] The Table below compares emissions factors from EPA's 2021 proposal, the current proposal, and what we recommend in accordance with our GHGRP comments.

Table 15: **Production and G&B Pneumatic Controller Emission Factors**

Production and G&B	EPA's 2021 OOOOb/c Proposal	EPA's 2022 OOOOb/c Proposal	Joint Commenter's Proposal
Low-Bleed	2.6	6.8	7.6
High-Bleed	16.4	21.2	19.3
Intermittent-Bleed	9.2	8.8	11.2

Though EPA's analysis has improved significantly, EPA likely still overestimates the costs, and underestimates the cost-effectiveness, of zero-emitting pneumatic controllers. We therefore suggest further improvements to its cost analysis.

First, as we noted in our previous comment, EPA's small, medium, and large model plants do not reflect the actual average size of transmission and storage facilities (based on the average size reported in EPA's GHGI). EPA did not address this issue in response to comments and continues to inaccurately size its model plants. This has likely resulted in EPA underestimating cost-effectiveness, as zero-bleed conversion becomes more cost-effective as the size of the plant increases. We recommend that EPA increase the size of its model plants to accurately reflect average plant sizes.

Second, EPA inappropriately increased installation cost estimates for electric controller systems in its updated analysis. As described in a new 2023 memo from Carbon Limits,[266] EPA's new, higher installation costs may be appropriate for certain remote sites (such as those in Northern Alberta) where travel costs can be fairly high. EPA's estimates therefore now represent the upper range of installation costs that are applicable only to a small number of sites. But in proposing a national standard, EPA should consider average installation costs, or costs that will be representative of sites nationally. Those average installation costs are presented in the Carbon Limits tool and are much lower than EPA's current estimates, meaning EPA is likely

[264] Env't Def. Fund, Comments to EPA's "Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule" (Oct. 6, 2022) (Docket No. EPA-HQ-OAR-2019-0424), https://blogs.edf.org/energyexchange/files/2022/10/EDF-GHGRP-Comments-10.6.2022-Final.pdf.

[265] *See* Clean Air Task Force, *Comments on Revisions and Confidentiality Determination for Data Elements Under the Greenhouse Gas Reporting Rule*, at 17–19 (Oct. 6, 2022) (Doc. ID No. EPA–HQ–OAR–2019–0424), https://www.regulations.gov/comment/EPA-HQ-OAR-2019-0424-0248.

[266] Carbon Limits, 2023 Memo, *supra* note 257.

overestimating installation costs and underestimating cost-effectiveness. We recommend that EPA use Carbon Limits' average installation cost estimates.

Though EPA's new analysis could be improved, it is much more robust overall for the reasons outlined above. With this strengthened analysis that aligns more closely with the best supporting evidence, EPA has found zero-bleed pneumatic controllers to be cost-effective. We therefore support EPA's determination that the controller standard is cost-effective.

b. EPA's standard is cost-effective and feasible for a variety of circumstances in which pneumatic controllers will be deployed.

EPA's BSER analysis demonstrates that EPA's pneumatic controller standard is cost-effective and feasible for a range of circumstances in which pneumatic controllers will be deployed.

i. EPA has demonstrated solar is cost-effective and feasible at remote locations without electricity.

EPA has found the installation of solar-powered systems to be cost-effective, and its determination that these systems are feasible at remote sites without electricity is supported by strong record evidence. In its supplemental proposal, EPA soundly addressed purported limitations associated with solar systems – including geographic conditions, temperature, battery capacity, snow cover and particle accumulation on panels, and large-scale applicability. It noted that Canadian provinces with colder temperatures and significant snowfall have successfully implemented non-emitting controller regulations that include solar as a primary remote compliance option; that it received comments by vendors that reported successful installation and operation of emission controller systems in a variety of climate conditions and one who commented on the installation of solar-driven instrument air systems in several states, including Wyoming and Colorado; that technology providers interviewed for the Carbon Limits report have solar-powered controllers installed at well sites in remote and cold locations in places like Northern Alberta and British Columbia without major reliability issues; that one provider interviewed by Carbon Limits installed solar systems at over 400 well-sites in Alberta and British Columbia; that solar panels are placed vertically to eliminate snow cover during winter months; and that solar technology has improved significantly over the years.[267]

EPA can add to the record in support of solar feasibility by noting that (1) the Carbon Limits report, which EPA uses in its updated cost analysis, accounts for low temperatures and reduced battery capacity;[268] (2) that an independent report by Analysis Group considers region-specific solar capacity factors at all sites, including extra-large sites, and finds cost-effectiveness across all regions;[269] (3) that the same report accounts for particle accumulation on solar panels,[270] (4)

[267] 87 Fed. Reg. 74764.
[268] *See* Carbon Limits, 2021 Report 5–6 (included in 2022 Joint Environmental Comments, *supra* note 1, as Attachment N).
[269] Analysis Group, *Methane Reduction Technology Electricity and Abatement Costs: The Cost to Power Zero-Emission Pneumatic Controllers and Pumps in Grid-Connected and Remote Locations*, at 17–18, 46 (May 6, 2022) [hereinafter Analysis Group Report] (included as Attachment M).
[270] Analysis Group, *Methane Reduction Technology Electricity and Abatement Costs: Summary Presentation for EPA* (May 10, 2022) [hereinafter Analysis Group Presentation] (included as Attachment N).

and that the Carbon Limits model, which EPA relies on, has a default assumption to oversize the solar panel by 50% for electric controllers and 30% for solar-powered instrument air systems, so that a loss of generation due to factors such as particle accumulation will not degrade system performance.[271]

ii. EPA has demonstrated that the zero-emission standard is cost-effective and feasible at large and small sites.

EPA's controller standard is cost-effective and feasible at a wide range of site sizes, as well, including EPA's small model plant (4 controllers), medium model plant (8 controllers), and large model plant (20 controllers). As demonstrated in EPA's Table 25,[272] zero-emitting options are cost-effective for all technologies at small sites in each segment, except for grid instrument air systems in the transmission and storage segment; it is cost-effective for all technologies at medium sites in each segment, except for instrument air systems in the transmission and storage segment; and it is cost-effective for all technologies at large sites within each segment, without exception.

EPA has also demonstrated cost-effectiveness at extra-small sites. EPA performed an analysis of the cost effectiveness of the use of electric controllers and solar-powered controllers at sites with a single controller. For sites with only one high-bleed controller, the cost effectiveness was estimated to be $379 and $437 per ton of methane reduced for electric and solar-powered controllers, respectively. For a site with one intermittent vent controller, the cost effectiveness values were estimated as $913 per ton for electric controllers, and $1,053 per ton for solar-powered controllers. For a site with one low-bleed controller, the cost effectiveness values were $1,181 per ton for electric controllers and $1,363 per ton for solar-powered controllers. These all fall below EPA's cost-effectiveness benchmark. Our independent analysis supports EPA's conclusion. Running the Carbon Limits 2021 tool shows that converting to zero-bleed remains cost-effective even for sites with just one intermittent controller, especially when considering multi-pollutant costs.[273]

This landscape demonstrates cost-effectiveness and feasibility of the standard. Where one technology is less cost-effective, another technology can be implemented. For example, though grid-instrument air is less cost-effective at EPA's model small and medium sites in the transmission and storage segments, grid-connected electric controllers and solar-powered electric controllers are very cost-effective, even, as discussed above, at extra-small sites with one controller.

EPA can further bolster its analysis by noting that the 2021 Carbon Limits report found cost-effectiveness for solar-powered instrument air systems at smaller sites.[274] It should also run the

[271] Carbon Limits, 2021 Report, *supra* note 268, at Appendix A: List of assumptions, Table A. 1: Quantitative assumptions for the model.
[272] 87 Fed. Reg. 74762–63.
[273] *See* Clean Air Task Force, *Pneumatic Controller Spreadsheet* (2023) (included as Attachment O). EPA estimated capital and operating costs for new and existing sites with a single controller, but it did not complete the analysis to calculate abatement costs. In the attached spreadsheet, we complete this analysis to show that retrofit is cost effective, even at sites that have only a single intermittent controller and without access to grid electricity.
[274] Carbon Limits, 2021 Report, *supra* note 268, at 7–9, 14.

Carbon Limits tool on a smaller model plant to illustrate cost-effectiveness at extra-small sites across segments. Finally, EPA should also note that the Analysis Group report, discussed below, finds cost-effectiveness for extra-large sites containing 200 controllers.

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

An independent report by Analysis Group assessing the costs to operate zero-emission technologies further demonstrates the cost-effectiveness of EPA's pneumatic controller proposal, with specific emphasis on the cost-effectiveness of these technologies by region, including the Midwest, Mid-Atlantic, South, Rocky Mountains, and Alaska.[275] The report concludes that, after incorporating electricity and net maintenance costs, all technologies considered (grid-connected, solar, and instrument air) are cost-effective at small, medium, and large plants in all regions, even when gas savings are not considered.[276] The report's findings supplement EPA's conclusions with its regional focus and because it incorporates additional and varied cost factors. Some highlights of the report include:

- *Solar Controller Analysis Considers Regional Conditions, Particle Accumulation, and Large Solar Sites:* The report's solar controller evaluation accounts for a potential decrease in solar/storage output in colder climates[277] and due to particle accumulation on panels.[278] The model assumes ten days of energy storage at a maximum depth discharge of 80%.[279] Additionally, solar levelized costs were adjusted regionally based on differences in solar capacity factors.[280] Even after incorporating these variances into the model, the report finds that the installation of zero-emitting pneumatic controllers is cost-effective in each region, including Alaska, countering claims that facilities in colder and cloud-covered states cannot feasibly install solar-driven controllers and that particle accumulation makes solar infeasible. The report also considers oversizing the solar array and battery storage[281] to the extent necessary to ensure sufficient generation to power controllers. Based on these assumptions, in combination with its use of independent regional levelized costs of solar and storage, the report finds that large facilities are capable of using solar controller systems cost-effectively.
- *Consideration of Extra-Large Sites:* The report supplements EPA's analysis by considering extra-large sites. It considers sites with electricity demand reaching 2,000 kW by modeling an extra-large plant size of 200 controllers for production and transmission and storage sites,[282] and finds that nearly all technologies would be cost effective. This counters certain industry commenters' claims that zero-emitting technologies are not cost-effective at plants that are larger than EPA's model plants or at sites requiring 2,000 kW of electricity.

[275] *See* Analysis Group Report, *supra* note 269.
[276] *Id.* at 4.
[277] *Id*. at 46.
[278] Analysis Group Presentation, *supra* note 270, at 12.
[279] Analysis Group Report*, supra* note 269, at 18.
[280] *Id*.
[281] *Id*. at 17.
[282] *Id*.

- *Adjusted Capital Expenditures:* The report's grid-powered, solar, and instrument air controller analyses all include adjusted capital expenditures for equipment, prepared independently of EPA's analysis.[283]
- *Maintenance Costs*: Unlike EPA's original analysis (but like the analysis for its supplemental proposal), the analyses for all three technologies incorporate net maintenance costs, which result in savings associated with replacing gas-driven controllers with zero-emitting controllers.[284]
- *Costs of Service Extension:* The report further supplements EPA's costs analysis by considering the costs for locations that do not have electricity supply on-site, but are located close enough to the local electric distribution system to consider developing a line extension from the closest spot on the grid. The report finds that, in most situations, the cost of constructing a distribution line when an operator is 0.5 miles away from access plus electricity use results in cost-effective methane abatement.[285] While cost-effectiveness may decrease with more distance from the grid, this conclusion rebuts certain industry commenters' claims that the cost to obtain grid access is prohibitive.[286]
- *Electricity Costs:* The report's grid-powered and instrument air analyses consider electricity costs by region. The report estimates the cost of delivered electricity as the average of state prices for electricity to ultimate customers,[287] and finds that installation of zero-emitting pneumatic controllers would be cost-effective in all regions.[288]

3. *Supply chain considerations do not alter the reasonableness of EPA's proposal.*

EPA is seeking comment on whether supply chain constraints might limit the availability of pneumatic controllers. In this section we demonstrate why EPA's proposed standards are eminently feasible given the reasoning already set forth by EPA in its proposals and by highlighting a recent report assessing the state of the pneumatic controller provider industry.

a. *The record set forth by EPA demonstrates strength in the supply chain.*

The record set forth by EPA in its 2021 proposal and the supplemental proposal demonstrate that complying with EPA's zero-emitting technology standard is feasible despite purported concerns that supply chain conditions present an obstacle.

First, as EPA notes, four and a half years will pass between the time EG OOOOc is finalized and the compliance dates for state rules, allowing substantial adjustments in the supply chain in reaction to the rules. Operators have noted that they have experienced "delays of several months" but that is not the type of delay that would make complying with EPA's four and a half-year

283 Analysis Group Report, *supra* note 268, at 45–47.
284 *Id*. at 45–47.
285 *Id*. at 23, 24–26.
286 *See* Amer. Petroleum Inst., *Comments on EPA's Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review* 7–8 (Jan. 31, 2022), https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-0808 [hereinafter 2022 API Comments].
287 Analysis Group Report, *supra* note 269, at 17.
288 *Id*. at 24–26.

timeline infeasible. And operators have generally been able to transition their fleets within EPA's proposed schedule. EQT, the largest natural gas producer in the United States, retrofit all of its sites to eliminate natural gas-driven controllers in less than one and one-half years.[289] And Diamondback anticipates it will have replaced "nearly all" of its controllers with zero-emitting devices within four years.[290] And Diamondback anticipates it will have replaced "nearly all" of its controllers with zero-emitting devices within four years.[291]

Second, EPA set forth strong record evidence regarding the availability of solar-driven systems, *see supra* section D(2)(b)(i), which is an important option for remote sites. For example, EPA noted one provider that has installed solar systems at over 400 well-sites in Alberta and British Columbia, and cited comments from several providers of solar-driven systems. Critically, as EPA explains in this proposal, operators have thus far not provided evidence that there is inadequate supply of solar-driven technology.

b. Datu research report further demonstrates strength in the supply chain.

In addition to EPA's own analysis, a recent report by Datu Research further underscores that the supply chain for the production of zero-emitting technologies is not a barrier for industry-wide adoption of zero-emission controllers and that, on the contrary, the supply chain is strong enough to support implementation of EPA's proposed standards.[292]

Datu's report identifies forty providers of zero-emitting controllers and surveyed nine.[293] Its interviews with these providers demonstrate that suppliers are well equipped to meet anticipated demand within EPA's proposed regulatory timeline. Datu also re-surveyed providers after MERP's passage, and providers indicated that MERP, in addition to EPA's regulations, will further catalyze the production and distribution of zero-emitting devices. The report's key findings include the following:

- *A well-established, capable set of zero-emission controller providers is in place.* The report identified 40 providers of zero-emitting pneumatic controller equipment, several of which manufacture long-established technologies used across industries. Many of the 40 listed are mature companies that have served the oil and gas industry for decades, with a median 43 years in operation.[294] These companies also serve on average five different industries, indicating providers have a wide demand base.[295]
- *Zero-emission controller components are mature and designed to integrate into existing systems.* Components like electric actuators and instrument air compressors have been in

[289] *EQT Eliminates Nearly 9,000 Natural Gas-Powered Pneumatic Devices*, PRNewswire (Jan. 4, 2023) https://www.prnewswire.com/news-releases/eqt-eliminates-nearly-9-000-natural-gas-powered-pneumatic-devices-301713418.html.
[290] Diamondback Energy, *2021 Corporate Sustainability Report* 8 (2021), https://www.diamondbackenergy.com/static-files/faf5ab25-5ab5-4404-8c04-c7bd387ae418.
[291] *Id.*
[292] Datu Research, *Zero-emission Alternatives to Pneumatic Control: How Ready are Technology Providers to Meet Increased Demand?* (Jan. 2023) (Attachment P).
[293] *Id*. at 5, 9.
[294] *Id*. at 5.
[295] *Id.*

use for decades, and providers of these components emphasize that integrating them into existing natural gas-driven systems is fairly simple.[296]

- *Technology providers already see strong demand for retrofits and new installs*. In their interviews, providers noted that their oil and gas clients are already choosing alternatives to natural gas-driven controllers not only because of anticipated regulations, but also because of the economic benefits – including preserving saleable product, maintenance cost savings, and less downtime – and the safety benefits associated with reducing flammable product in the workplace.[297] Companies are also preferring electronic systems because of their intelligent connectivity capabilities that keep on-the-ground information flowing continuously.[298] Five companies interviewed indicated that 60-90% of their sales were for retrofits.[299]
- *Technology providers have strategies for meeting current supply chain challenges*. Though procurement delays have been a reality for some suppliers, they have employed strategies like paying higher prices, storing extra quantities of supplies, bringing in more procurement personnel, going to different distributors, spot-buying on the open market, and finding contract manufacturing sites. Larger companies reported facing fewer hurdles.[300]
- *Regulatory certainty steadies demand.* Even considering supply chain concerns, providers have confidence in their ability to expand production capacity so long as regulatory certainty helps keep demand steady over multiple years.[301]
- *MERP is already increasing demand for zero-emitting alternatives and will likely bring innovation and new technology providers into the US market.* Providers reported that MERP has resulted in an increase in purchase orders and that they anticipate MERP will accelerate the transition to zero-emitting technologies.[302]

The report contains a number of direct quotes from providers illustrating the points above. Below is a small sampling:

- "We supply a lot of valves and pneumatic controls for the valves. They've been around a long time. They're just changing from natural gas actuation to compressed air, and there's no need to change the design; it's a cylinder actuated by pressure and it doesn't matter whether it's gas or air."[303]
- "We are dealing with such basic materials and longstanding technology. The closest thing to a delay is crossing the [Canada-U.S.] border."[304]
- "We focus on pre-engineered configurations of different physical sizes and that allows us to integrate into different systems. We enable the use of typical off-the-shelf

[296] *Id*. at 8.
[297] *Id*. at 9.
[298] *Id*. at 14
[299] *Id*. at 9.
[300] *Id*. at 3.
[301] *Id*. at 11–12.
[302] *Id*. at 12–13.
[303] *Id*. at 8.
[304] *Id*. at 8.

compressors. We have the ability to use a wide range of suppliers for different scales. We can use several manufacturers."[305]

- "It would not take us long to double our output. The skilled labor going into each unit is readily available [and] supply chain . . . will improve over time."[306]

These findings – individually, and certainly as a collection – indicate that suppliers are currently delivering zero-emitting solutions and prepared to continue to do so at scale. Dozens of providers of zero-emitting technologies are already well-established, many with long-lasting supplier relationships; operators are starting to voluntarily choose alternatives to natural gas-driven controllers for economic and safety reasons; components that have been on the market for decades are easy to integrate into retrofitted systems; and the existing high demand for zero-emitting equipment coupled with regulatory and legislative certainty provided by EPA's regulations and MERP is giving suppliers the demand and confidence needed to commit to contracts and scale up capacity. All of these factors point to a stable, growing supply chain for zero-emitting equipment.

4. Grid connection and grid power requirements

There are two issues concerning the feasibility of the zero-emission standard and grid connectivity that we address below.

The first is that operators have incorrectly suggested that the feasibility of the zero-emission standard is somehow dependent on the availability of grid connection. Grid connection, however, does not present a barrier to widespread deployment of zero-emitting controllers. In instances where operators do not have access to the grid or grid access is cost prohibitive, the proposed regulation is flexible and provides operators a number of commercially available and cost-effective options to achieve the standard. Operators that cannot access grid electricity can still use electric or instrument air systems powered by solar energy, or can use natural gas-driven controllers that are self-contained or routed to a process, all of which, as discussed, are cost-effective and feasible across the United States. Accordingly, the availability of grid connection has no bearing on the reasonableness of EPA's standards.

The second is that operators have suggested that compliance with the zero-emission standard is infeasible at sites requiring large electricity demand. However, for sites that are already connected, using that connection to power electronic controllers is cost-effective across-the-board, including at sites with high demand. The Analysis Group report shows, for example, that all zero-emitting technologies at extra-large sites using 2,000 kW are cost effective even when including the cost of electricity.[307]

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[305] *Id*. at 8.
[306] *Id*. at 12.
[307] Analysis Group Report, *supra* note 269, at 15; *see also* Analysis Group Presentation, *supra* note 270, at 12.

5. *EPA properly defines the affected facility as all controllers at a site for new, modified, and reconstructed facilities.*

EPA proposes that the pneumatic controller affected facility be defined as the collection of natural gas-driven pneumatic controllers at a well site, centralized production facility, onshore natural gas processing plant, or a compressor station.[308] EPA's proposal specifies that, if one or more pneumatic controllers is added to the site, such addition constitutes a "modification" under the Clean Air Act and the collection of pneumatic controllers at the site becomes a pneumatic controller affected facility subject to OOOOb. EPA also interprets "reconstruction" under Clean Air Act to mean the replacement of greater than 50 percent of the number of existing controllers onsite and that all controllers at the site become subject to OOOOb once this threshold is met.[309]

Joint Environmental Commenters support EPA's updated affected facility definition. In EPA's initial proposal, there was a disconnect between the pneumatic controller affected facility definition (i.e., an individual controller) and the cost analysis, which was based on the replacement of all pneumatic controllers with zero-emitting devices at a site.[310] Aligning the affected facility definition with EPA's cost model strengthens EPA's cost analysis, the BSER analysis, and the proposal overall. Operators of oil and natural gas facilities also usually calculate overall site-wide emissions from pneumatic controllers.[311] Moreover, it makes the most technological sense for operators to convert to zero-emitting controllers on a site-wide rather than piecemeal basis.[312] For instance, compressed air systems are used to power all pneumatic controllers at a site, rather than there being separate systems for each controller. Similarly, a solution based on solar energy would likely utilize a single array of solar panels to provide power to all the controllers at the site. It's also much more cost-effective for operators to conduct site-wide conversions of controllers than it is to make single or smaller replacements.[313] Because in practice operators will likely be converting controllers site-wide, it is more sensible for EPA to similarly define the affected facility as all controllers at a given site.

Joint Environmental Commenters also support EPA's application of "modification" and "reconstruction" in this context, and its conclusion that a modification or reconstruction would result in all controllers at a site becoming a new pneumatic controller affected facility subject to OOOOb.

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[308] 87 Fed. Reg. at 74766.
[309] 87 Fed. Reg. at 74757.
[310] 87 Fed. Reg. at 74756.
[311] *See* GPA Midstream Assoc., *Comment on Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources* at 23 (Jan. 31, 2022) (Doc. ID No. EPA-HQ-OAR-2021-0317-0817), https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-0817.
[312] Carbon Limits, *Zero emission technologies for pneumatic controllers in the USA: Applicability and costeffectiveness* at 13 (2016), https://cdn.catf.us/wp-content/uploads/2019/09/21093627/CL2016-ZeroEmitting-Pneumatics-Alts-1Aug2016.pdf [hereinafter Carbon Limits, 2016 Report].
[313] *Id.* at 13. The Cost model assumes that all pneumatics at a site are converted.

Under the Clean Air Act, modifications and reconstructions at an affected facility render the entire source "new" and thus subject to OOOOb.[314] Specifically, 40 C.F.R. § 60.14 states that, "[u]pon modification, an existing facility shall become a[] [OOOOb] affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere." And 40 C.F.R. § 60.15 states that "[a]n existing facility, upon reconstruction, becomes an affected facility [subject to OOOb], irrespective of any change in emission rate."

"Modification" is defined under the Act as "any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant." Here, whether a modification triggers application of OOOOb for all, some, or just one controller at a site depends on the affected facility definition. A modification to an affected facility that is defined as a single controller would mean that the sole controller becomes subject to OOOOb, whereas a modification to an affected facility defined as the collection of controllers at a site would mean the collection of controllers becomes subject to those standards. As explained above, EPA has reasonably defined an "affected facility" as the collection of controllers at a site. And in applying this definition, EPA's clarification that all controllers at a facility become subject to OOOOb after the addition of one or more pneumatic controllers is accurate, since doing so would be a physical change resulting in increased emissions. This is the definition of "modification" under the Act, and would necessitate the conversion of all controllers at the site to zero-emission technologies.

To be clear, the addition of natural gas-driven controllers, including self-contained and routed controllers, would constitute a modification under the Act. EPA acknowledges that without regulatory requirements, these controllers have the potential to emit methane and VOCs.[315] Therefore, the addition of one of these controllers prior to being regulated by EPA would result in an increase in emissions at the site, constituting a modification.[316]

EPA's interpretation of "modification" not only meets the Act's statutory definition but also helps to create certainty for operators. As explained, installing zero-emission controllers site-wide creates efficiencies and increased cost-effectiveness due to shared equipment usage.[317]

EPA also correctly interprets "reconstruction" for sites with pneumatic controllers and how that definition would trigger application of OOOOb. EPA interprets "reconstruction" to mean when a site replaces greater than 50 percent of the number of its existing controllers. The threshold

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[314] Under section 111 of the Clean Air Act, the NSPS applies to "new sources." 42 U.S.C. § 7411(b)(1)(B). "New sources" are "any stationary source, the construction or modification of which is commenced after the publication of regulations . . . prescribing [NSPS] applicable to such source." *Id.* § 7411(a)(2).

[315] *See* 97 Fed. Reg. at 74759 ("While the EPA understands that these controllers have zero routine emissions from the operation of the device and are therefore compliant with the proposed standard when they are properly operated and maintained, they do have the potential to emit methane and VOC if they are not operated and maintained properly. However, since they are powered by natural gas, the potential for emissions exists if they are not maintained and operated properly. For instance, a self-contained controller could malfunction or develop leaks, or a CVS that is routing the controller emissions to a process could develop leaks.").

[316] Put another way, once self-contained and routed controllers become subject to EPA's requirements, they will presumably reduce their emissions to zero, but at the time of installation, these controllers will increase emissions, constituting a modification.

[317] Carbon Limits, *Zero Bleed Pneumatics Cost Tool* (included in 2022 Joint Environmental Comments, *supra* note 1, as Attachment Q).

percentage includes all pneumatic controllers which are or will be replaced pursuant to all continuous programs of pneumatic controller replacement that are *commenced* within any 2-year period.[318] EPA provides several examples to illustrate how it would determine when a replacement falls within the two-year period.[319]

EPA's interpretation aligns with the Clean Air Act's "reconstruction" definition, which means the replacement of components of an existing facility to such an extent that "the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility." In accordance with this definition, it is reasonable for EPA to equate replacing 50 percent of controllers at a site with 50 percent of the fixed capital costs required to construct an entirely new facility. If the affected facility is all controllers at a site, which, as explained previously, is appropriate, then 50 percent of the cost to construct an entirely new "facility" would amount to replacing 50 percent of controllers at the site. Since individual controllers are likely to have comparable replacement costs, it is reasonable to assume that there would be a one-to-one correlation between the percentage of controllers being replaced at a site and the percentage of the fixed capital cost that would be required to construct an entirely new comparable facility.

EPA clarifies that its proposed change to a site-wide pneumatic controller affected facility definition would allow the replacement of existing high-bleed controllers with low-bleed controllers without becoming an affected facility, provided that 50 percent or less of the controllers are replaced at the same time. However, it should also clarify that the replacement of any type of controller counts toward the 50 percent threshold, since the reconstruction definition does not require that there be an increase in emissions. For example, an existing site that replaces 50 percent of controllers with zero-bleed controllers, or an existing site that replaces 50 percent of its high bleeds with high bleeds or low bleeds, would render all controllers at the site a OOOOb facility.

It is also important that EPA establish a two-year window for determining whether replacements, taken together, make up 50 percent of the site. Without a two-year window, operators could create multiple replacement programs below the 50 percent threshold over the course of several years (e.g., 20% in October 2026, and 30% in September 2028) to avoid compliance with OOOOb. Allowing this loophole would undermine Congress' intent that air quality be enhanced over the long term with the turnover of polluting equipment, and with the intent of the EPA's reconstruction provisions.[320] The two-year period provides a reasonable method of determining whether an owner of an oil and natural gas site with pneumatic controllers is actually proposing extensive controller replacement, the exact type of program 40 C.F.R. § 60.1 was intended to regulate. The two-year time frame also recognizes that it is more cost effective to replace larger

[318] *See* 87 Fed. Reg. at 74758 ("EPA will count toward the greater than 50 percent reconstruction threshold all controllers replaced *pursuant to all continuous programs of controller replacement which commence* within any 2-year rolling period following proposal of these standards.") (emphasis added).
[319] *See* 87 Fed. Reg. at 74758.
[320] *See* Modification, Notification, and Reconstruction, 40 Fed. Reg. 58417 (Dec. 16, 1975) (also stating that "the purpose of the reconstruction provision is to recognize that replacement of many of the components of a facility can be substantially equivalent to totally replacing it at the end of its useful life with a newly constructed affected facility[]").

chunks of controllers rather than initiate several, smaller replacement programs.[321] We recommend that EPA clarify that "commencement" refers to commencement of the controller replacement program, not the replacement of an individual controller. For example, if continuous program A starts in October 2024 and replaces 30% of controllers, and continuous program B starts in September 2026 and replaces 21% of controllers, all the controllers that are part of both replacement programs would be counted in calculating the 50 percent calculation, even if some are replaced after October 2028, because it matters that those controllers are in fact a part of *program* B. Without this clarification, operators could still avoid triggering OOOOb requirements by replacing controllers through a segmented, step-wise process, even when those controller replacements are really part of a single replacement effort.

Finally, it is worth noting that EPA's proposed interpretation of "modification" and "reconstruction" aligns with those proposed in the context of storage tanks.[322] Uniformity on this point alleviates confusion for operators and regulators.

6. ***Inclusion of routed and self-contained controllers in the affected facility definition*.**

EPA proposes to include in the affected facilities definition (1) natural gas-driven controllers where the emissions are collected and routed to a gas-gathering flow line or collection system to a sales line, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve (i.e., generally characterized as "routing to a process") and (2) self-contained natural gas-driven controllers.

As affected facilities, these controllers would have to meet certain requirements to ensure they achieve zero methane and VOC emissions. EPA proposes that controllers routing emissions to a process must comply with the requirements in proposed 40 C.F.R. § 60.5411b(a) and (c). These include certification by a professional or in-house engineer that the CVS was designed properly and is operated with no identifiable emissions, as demonstrated through initial and periodic inspections, observations, and measurements. These inspections include quarterly monitoring using OGI in the proposed fugitive monitoring program or the alternative standards proposed in section 60.5398b. All issues identified would need to be corrected in line with the CVS requirements and required records would include the certification and records of all inspections and any corrective actions to repair the defect or the leak. EPA further proposes that self-contained controllers be designed and operated with no identifiable emissions, as demonstrated by initial and quarterly inspections using OGI and any necessary corrective actions.[323] Required records would similarly include records of all inspections and any corrective actions to repair the defect or the leak.[324]

[321] Carbon Limits, *Zero Bleed Pneumatics Cost Tool*, *supra* note 317 (included in 2022 Joint Environmental Comments, *supra* note 1, as Attachment Q).
[322] *Infra* section IV.I.
[323] *See* Proposed 40 C.F.R. §§ 60.5416b, 60.5397b.
[324] EPA is proposing to require the same continuous compliance requirements to self-contained controllers as those for covers and CVS. That is, the EPA is proposing to require the operation of self-contained pneumatic controllers with no identifiable emissions, as demonstrated through quarterly OGI monitoring. The repair requirements described for CVS would also apply to bring the self-contained pneumatic controller back into compliance. *See* 87 Fed. Reg. 74806.

Joint Environmental Commenters agree that it is reasonable to allow operators to use these natural gas-driven controller options. Though grid-powered, solar, and instrument air controllers are all readily available and cost effective, and operators can replace their fleets within EPA's proposed timeline using non-natural gas-driven alternatives, allowing routed and self-contained controllers provides operators with more technological flexibility. With that said, if EPA does permit use of these controllers, it must (as it has proposed) apply protective leak monitoring requirements. Specifically, EPA should ensure that natural gas-driven controllers (even if self-contained or routed to a process) are inspected quarterly with OGI cameras (or the equivalent alternative). Further, a discussed below, these options are warranted only if EPA retains the proposal as is, without additional exemptions.[325]

7. Exemptions

EPA has not proposed a technical infeasibility exemption for operators. We support this position and incorporate by reference our November 2021 comments for our reasoning.[326] We believe a technical infeasibility exemption would be even more inappropriate if EPA permits self-contained and routed controllers for compliance, as it has proposed to do. By allowing operators to comply using an even broader array of cost-effective technologies, there is no scenario in which an operator would need a technical feasibility exemption from the standard. Though EPA has not proposed a broad exemption, it has proposed an exemption for emergency shutdown devices and seeks comment on others. Below, we respond to EPA's questions regarding these various potential exemptions.

a. Exemption for emergency shutdown devices

EPA has proposed that natural gas-driven pneumatic controllers that function as emergency shutdown devices (ESDs) be exempt from the affected facility definition, provided that the records are maintained to document these conditions. We think an exemption for ESDs is reasonable, but urge EPA to include natural gas-driven controllers used for ESDs in the affected facility definition so that EPA can impose specific requirements to ensure that operators only utilize this exemption for these controllers. EPA must then clarify what records must be maintained to allow operators the exemption. We recommend that to utilize this exemption, operators must identify the precise natural gas driven controllers needed for ESDs in their annual and subsequent reports.

b. Exemption for temporary equipment

Although EPA does not propose an exemption for temporary equipment, it seeks comment on this type of exemption. We urge EPA to reject this option. Temporary equipment moves around and degrades quickly, making it prone to leakage and malfunctions leading to excess venting. As a result, standards for temporary equipment should be at least as stringent as those for permanent installations. One industry commenter noted that an exemption is needed because temporary equipment is often remote, in which case it might be hard to connect to the grid or an

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[325] *See*, *e.g.*, Cal. Code Regs. tit. 17 § 95669(n) (2023) (requiring that California operators replace components that require repair five or more times over a 12-month span).
[326] 2022 Joint Environmental Comments, *supra* note 1, at 165–67.

onsite control device, solar panels is a perfectly feasible and cost-effective option. solar panels is a perfectly feasible and cost-effective option.

If EPA includes an exemption for temporary equipment, it should be at least as protective as the exemption for temporary equipment in Colorado, and ideally more so. That state's AQCC Regulation 7, Part D, Section III.C.4.e[327] allows operators to use controllers that emit natural gas located on temporary or portable equipment that is used (1) for well abandonment activities,[328] (2) prior to or through the end of flowback,[329] (3) for up to 60 days upon notice to the Air Pollution Control Division,[330] and (4) for longer than 60 days if the operator submits justification to the Division for continued use at least 14 days before the 60-day period expires.[331] Under this regulation, operators are not permitted to use temporary equipment to increase production or on equipment which would increase the throughput capacity of a facility, as operators should be required to design operations for an increase in production from the start.

For use beyond 60 days, the operator may seek an extension from the Division by submitting justification at least 14 days prior to the end of the 60-day period based on certain information, including:[332]

- the type of temporary or portable equipment and the number and type of emitting controllers;
- how long the operator plans to keep the equipment onsite;
- the reason for the extension, including:
    - the basis for the extension,
    - the anticipated schedule for use of the equipment, and
    - the steps taken to minimize the length of the requested extension;
- and any other information the Division requires.

The Colorado regulations also require owners or operators utilizing temporary or portable equipment with pneumatic controllers that emit natural gas to conduct AVO and Approved Instrument Monitoring Method (AIMM) inspections of those controllers on the same schedule as the associated well production facility or compressor station,[333] and to comply with repair, recordkeeping, and reporting requirements.[334]

If EPA decides to include an exemption for temporary equipment (and it should not), it should require a similar approach. EPA should limit any temporary equipment exemption to the activities outlined above, and otherwise enforce a time limit of 30 days. The agency should also require that operators seeking to extend the exemption file a request no later than two weeks before the 30-day limit expires. The request should include the type of equipment being used, the

[327] 5 Colo. Code Regs. § 1001-9-D-III.C.4.e. (2023).
[328] *Id.* § 1001-9-D-III.C.4.e.(i)(B).
[329] *Id.* § 1001-9-D-III.C.1.e.(iv)(B).
[330] *Id.* § 1001-9-D-III.C.4.e.(i)(C).
[331] *Id.*
[332] *Id.* § 1001-9-D-III.C.4.e.(i)(C)(2)(a).
[333] *Id.* § 1001-9-D-II.E.
[334] *Id.* § 1001-9-D-II.E.6.

time needed, and the reasons for the extension request. Finally, EPA should be required to review and either approve or reject the extension request before the 30-day limit expires.

c. Exemption for smaller sites

We agree with EPA that it should not permit an exemption for smaller sites. We agree with EPA's sound reasoning[335] and, as discussed in section (D)(2)(b), concur that operators of small sites can cost-effectively implement the standard.

d. Exemption allowing natural gas system back ups

EPA seeks comment on whether to allow natural gas system back-ups, which certain industry commenters have requested in the event their zero-emission system fails.

EPA should reject this proposal. As EPA notes, allowing these backup systems would result in a potential loophole that would enable owners or operators to continue to use natural gas-driven controllers in routine situations. In this way, the allowance would amount to a broad exemption from the standard, which, as discussed above, is not necessary given the wide array of available technologies – including natural gas-driven controllers – that operators will be able to use to comply. Moreover, industry's analysis regarding the need for such systems is flawed. Carbon Limits interviewed several zero-emission controller technology providers and operators using such controllers at their facilities, and none of these companies indicated a need for a natural gas system backup.[336] Furthermore, none of the rules in Colorado, New Mexico, or British Columbia – all of which prohibit venting natural gas-driven controllers at new sites and require significant retrofits of such devices at existing facilities – allow operators to use venting gas-driven controllers as a back-up. Clearly, such back-up systems are not necessary.

Such an exemption would also be extremely difficult to monitor. Operators would need to show the need to use emitting devices arose due to a system failure, which would require confirmation from EPA in *each* instance and necessitate personnel and continuous monitoring. If EPA is unable to monitor the use of these natural gas back-ups, this exemption would swallow the rule, effectively displacing the zero-emission standard that EPA has demonstrated is cost-effective and feasible.

8. Emissions guidelines compliance timeframe

EPA proposes to require state plan submission within 18 months of the final regulations and final compliance no later than 36 months following plan submission, providing a total of four-and-a-half years for OOOOc implementation after the final regulations are in place. EPA has proposed that pneumatic controllers follow this timeline, so operators will have four-and-a-half years from the time of a final rule to retrofit to zero-emitting devices. Joint Environmental Commenters believe this is a reasonable amount of time but suggest that that a shorter timeline of two to three years would be feasible and cost-effective.

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[335] *See* 87 Fed. Reg. at 74769.
[336] Carbon Limits, 2023 Memo, *supra* note 257.

First, operators have demonstrated that EPA's timeline, and shorter timelines, are feasible. EQT, the largest natural gas producer in the United States, recently converted its entire fleet of pneumatic controllers to zero-emitting devices, and did so within one-and-a-half years (ahead of their anticipated schedule),[337] while other companies have committed to following suit.[338]

Further, the Datu report, which is based on interviews of technology providers familiar with the components and manufacture of zero-emitting controllers, explains why operators will be able to retrofit their sites easily and within two to three years. The report highlights that zero-emission components can be easily integrated into existing systems with components that are readily available. For example, e years. The report highlights that zero-emission components can be easily integrated into existing systems with components that are readily available. Electric actuators and air compressors are common industrial equipment and have been in use for decades, and instrument air compressor manufacturers emphasize in the Datu report that their product design does not need to change significantly to replace natural gas-driven systems. Because retrofitting sites entails deploying equipment that has been in use for several years, suppliers will be able to use their long-standing procurement relationships to provide zero-emitting devices industry-wide over a two-to-three-year period.

Moreover, operators ultimately may even prefer to retrofit over a shorter period, as retrofitting larger portions of sites becomes more cost-effective and makes the transition more efficient.[339]

9. Inclusion of intermittent controllers

Joint Environmental Commenters support EPA's decision to include intermittent vent controllers in its proposed standards and incorporate by reference our 2021 comment on the matter.[340] This inclusion is essential: as shown above in Table 12, EPA estimates that over 1.5 million metric tons of methane - 71% of emissions from pneumatic controllers - are from intermittent vent controllers. We also support EPA's conclusion that using one intermittent controller should not exempt an operator from the standard. EPA's own cost analysis demonstrates the cost-effectiveness of the standard with one controller on-site. And our own analysis using the Carbon Limits tool concurs. The Carbon Limits 2021 tool shows that converting to zero-bleed remains cost-effective even for sites with just one intermittent controller, especially when considering multi-pollutant costs.[341] Finally, we support EPA's response to industry comments that emissions reductions from intermittent vent controllers are already captured in EPA's cost analysis for the proposed LDAR requirements. As EPA notes, the average emission factor that the EPA used considers low-emitting properly operating controllers, as well as those that are not operating properly and that are venting during idle, and EPA finds that factor is the correct factor to

[337] PRNewswire, *supra* note 289.
[338] Diamondback Energy, *supra* note 290.
[339] Carbon Limits, 2016 Report, *supra* note 312, at 27 (table showing that sites with more controllers have lower abatement costs).
[340] 2022 Joint Environmental Comments, *supra* note 1, at 162–63.
[341] *See* CATF, Pneumatic Controller Spreadsheet, *supra* note 273. EPA estimated capital and operating costs for new and existing sites with a single controller, but it did not complete the analysis to calculate abatement costs. In the attached spreadsheet, we complete this analysis to show that retrofit is cost effective, even at sites that have only a single intermittent controller and without access to grid electricity.

represent the "uncontrolled" emissions from the universe of intermittent vent controllers. Additionally, these devices are not accounted for in EPA's modeling of the LDAR provisions.[342]

E. Pneumatic Pumps

EPA has determined that the BSER for pumps is "pneumatic pump systems that do not use natural gas . . .at sites both with and without access to grid electricity" and proposes to require that operators use non-natural gas-driven zero-emitting pneumatic pumps in all segments.[343] However, EPA proposes to allow sites without access to electricity to use natural gas-driven pumps that route to a process and that achieves 100% VOC and methane reductions where the operator demonstrates that compliance with the baseline standard is technically infeasible. Further, where operators demonstrate that it is technically infeasible to route to a process, EPA proposes different control requirements depending on the number of natural gas-driven diaphragm pumps at the site. If there are four or more such devices on site, the operator must route to a control device that achieves 95% reductions, whether or not one currently exists on site. If there are fewer than four of those controllers, the operator must route to an *existing* control device that achieves 95% reductions. Thus, the proposed rule ensures that zero-emitting pumps will be used at sites with access to electricity, but contains site-specific flexibility for sites without electricity.

Joint Environmental Commenters are supportive of the improvements EPA has made to its pump standards. We agree that installing non-natural gas-driven pumps at sites with electricity is entirely feasible and cost-effective. However, we urge EPA to mirror the proposed pump standard with the proposed controller standard by including routed pumps as a compliance option and eliminating the tiered feasibility exemption at sites without electricity. [344] If EPA retains the tiered flexibility exemption, it must be strengthened in the ways we have outlined below.

Similar to the affected facility definition for pneumatic controllers, EPA also now proposes to define a pneumatic pump affected facility as the collection of all natural gas-driven pneumatic pumps at a site. This updated definition, combined with EPA's adjusted modification and reconstruction definitions for pneumatic pumps, is reasonable, consistent with the statute, and will help to ensure sites undertaking modification or reconstruction are deploying pollution-reducing technologies.

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[342] Supplemental TSD, *supra* note 121, at 5 (modeling Fugitive Emissions from Production Sites Using FEAST Attachment).
[343] In its November 2021 proposal, EPA had different requirements for different industry segments. For new pumps (both diaphragm and piston pumps) in the production and storage segments, the proposal would have required that emissions be routed to an existing control device that achieves 95 percent control, or to route to an existing VRU or process. For new pumps (both diaphragm and piston pumps) at gas processing plants, the BSER was to require zero emissions. The requirements for existing sources mirrored those for new sources but excluded piston pumps.
[344] We incorporate by reference our initial comment on this point. 2022 Joint Environmental Comments, *supra* note 1.

1. *EPA's pneumatic pump standard is cost-effective.*

EPA's analysis shows that zero-emitting pneumatic pumps are cost-effective across all segments.[345] EPA's cost analysis for pneumatic pumps remained largely unchanged between its 2021 and 2022 proposals.[346] The adjustments EPA made have rendered the analysis more robust and further supports the cost-effectiveness of conversion to zero-emitting pumps. Small changes from last year's analysis to this year's (which we support) include:

i. An adjustment in the methane and VOC content of gas in the transmission and storage segments;
ii. The calculation of costs for sites with both a diaphragm and piston pump (rather than just one or the other);
iii. The calculation of costs for compressed-air driven pumps in the production and gathering/boosting segments.

Notably, EPA's analysis now shows that conversion to electric pumps (either with access to grid electricity or solar-powered) or instrument air pumps is cost-effective, even if only a single diaphragm or piston pump is located at the site. And costs decrease as the number of pumps increase.

Though EPA's analysis is adequate, as stated in our 2021 comment,[347] we recommend that EPA further improve its cost analysis by considering whether controllers exist on-site. EPA's cost analysis noted that pneumatic pumps and controllers often use the same equipment.[348] Its cost analysis should reflect that reality. Such a change would result in increased cost-effectiveness for a zero-emission pneumatic pump standard.

2. *EPA should finalize pump standards that mirror its proposed controller standards and remove the technical infeasibility exemptions for sites without electricity.*

We strongly support EPA's decision to require non-natural gas-driven pumps at sites with electricity. However, because zero-emitting pumps are also feasible for operators at sites without electricity we urge EPA to finalize pump standards that mirror the proposed controller standards (including an allowance for routed natural gas-driven pumps in the baseline) and remove the tiered flexibility exemption. Critically, EPA has determined that the BSER for pumps at both sites with and without electricity is zero-emitting pumps, but permits the exemption for sites without electricity because it argues that there may be circumstances where the standard is infeasible.[349] We contend, however, that installation of zero-emission pumps is feasible in all instances and that a feasibility exemption will create a significant loophole in a standard that the EPA has determined is the BSER. We incorporate by reference the content in our previous comment on our support for a zero-emission pump standard, and provide further justification below.

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345 *See* Supplemental TSD, *supra* note 121, at 4–20.
346 87 Fed. Reg. at 74772.
347 2022 Joint Environmental Comments, *supra* note 1, at 173.
348 87 Fed. Reg. at 74770.
349 *Id.* at 74775.

First, as EPA's cost analysis demonstrates, remote options for non-natural gas systems like solar are cost effective for sites of varying size.[350] Table 16 below is reproduced from EPA's cost analysis and provides EPA's cost-effectiveness conclusions for non-natural gas-driven pneumatic pumps. Though EPA's analysis demonstrates cost-effectiveness, as EPA notes it is still likely underestimating costs as it does not account for the fact that certain sources, like compressed air systems and control devices, can be used for both controllers and pumps.[351]

Table 16

TABLE 30—SUMMARY OF COST EFFECTIVENESS FOR PNEUMATIC PUMP OPTIONS THAT DO NOT USE PUMPS DRIVEN BY NATURAL GAS

Segment Option - Representative Site	Cost Effectiveness ($/ton)[a] - Reasonable?				
	Single Pollutant		Multipollutant		Overall[a]
	Methane	VOC	Methane	VOC	
Production Segment					
Electric Pumps – Single Diaphragm	$310 -Y	$1,115 -Y	$115 -Y	$557 -Y	Y
Electric Pumps – Single Piston	$1,632 -Y	$5,869 -Y	$816 -Y	$2,934 -Y	Y
Electric Pumps – Multiple Pumps[b]	$441 -Y	$1,585 -Y	$220 -Y	$793 -Y	Y
Solar Pumps – Single Diaphragm	$103 -Y	$370 -Y	$51 -Y	$185 -Y	Y
Solar Pumps – Single Piston	$937 -Y	$3,371 -Y	$469 -Y	$1,686 -Y	Y
Solar Pumps – Multiple Pumps[b]	$185 -Y	$667 -Y	$93 -Y	$334 -Y	Y
Instrument Air – Single Diaphragm	$3,264 -N	$11,743 -N	$1,632 -Y	$5,871 -Y	Y
Instrument Air – Single Piston	$29,724 -N	$106,921 -N	$14,682 -N	$53,461 -N	N
Instrument Air – 1 Diaphragm/1 Piston	$2,941 -N	$10,581 -N	$1,471 -Y	$5,290 -Y	Y
Instrument Air – 2 Diaphragm/2 Piston	$1,471 -Y	$5,290 -Y	$735 -Y	$2,645 -Y	Y
Processing Segment					
Instrument Air – 2 Diaphragm/2 Piston	$1,471 -Y	$5,290 -Y	$735 -Y	$2,645 -Y	Y
Instrument Air – 10 Diaphragm/10 Piston	$944 -Y	$3,397 -Y	$472 -Y	$1,699 -Y	Y
Instrument Air – 50 Diaphragm/50 Piston	$424 -Y	$1,524 -Y	$212 -Y	$762 -Y	Y
Transmission and Storage Segment					
Electric Pumps – Single Diaphragm	$237 -Y	$8,563 -N	$119 -Y	$4,281 -Y	Y
Electric Pumps – Single Piston	$1,249 -Y	$45,083 -N	$624 -Y	$22,541 -N	Y
Electric Pumps – Multiple Pumps[b]	$337 -Y	$12,177 -N	$169 -Y	$6,088 -N	Y
Solar Pumps – Single Diaphragm	$79 -Y	$2,844 -Y	$39 -Y	$1,422 -Y	Y
Solar Pumps – Single Piston	$717 -Y	$25,897 -N	$359 -Y	$12,948 -N	Y
Solar Pumps – Multiple Pumps[b]	$142 -Y	$5,125 -Y	$71 -Y	$2,563 -Y	Y
Instrument Air – Single Diaphragm	$2,499 -N	$90,206 -N	$1,249 -N	$45,103 – N	N
Instrument Air – Single Piston	$22,751 -N	$821,348 -N	$11,376 -N	$410,674 -N	N
Instrument Air – 1 Diaphragm/1 Piston	$2,251 -N	$81,279 -N	$1,126 -Y	$40,640 -N	N
Instrument Air – 2 Diaphragm/2 Piston	$1,126 -Y	$40,640 -N	$563 -Y	$20,320 -N	Y

Second, the Analysis Group report cited in our discussion of pneumatic controllers (section D) analyzed the cost of various non-natural gas driven pneumatic systems that apply to pneumatic pumps, including grid-connected, solar, and instrument air, finding installation of these devices to be cost-effective across all U.S. regions. Notably, for sites without electricity, the report found solar pneumatic controller and pump systems to be cost-effective at sites across the United States, even in states with colder temperatures.

[350] *Id.* at 73773–74.
[351] *Id*. at 74770.

Third, there is evidence that zero-emission pumps are readily available and already being deployed in numbers. British Columbia and Alberta do not allow new emitting pumps.[352] Additionally, the Datu report identified 13 suppliers of solar-based systems that can be used in remote locations or at sites without electricity, including nine providers of instrument air solar compressors and four providers of solar-driven electric actuators.[353] As EPA itself notes, this equipment can be used for pumps in addition to controllers,[354] demonstrating the availability of suppliers of this type of technology. Further, in addition to the zero-emission pump providers cited in our previous comment, Pump Projects provides solar electric pumps with compressed air instrumentation,[355] and EPA cited several vendors who confirmed during the rulemaking process the successful implementation of pumps not driven by natural gas at remote locations, including locations with very harsh winter weather. [356] [357]

Fourth, EPA has determined that routed pumps are cost-effective and has included them as an option in the proposed OOOOb.[358] As with the controller standard, a zero-emission pump standard that allows these types of pumps would provide the flexibility needed to remove a technical infeasibility exemption for sites without electricity.

Fifth, the comments that EPA cites maintaining that "zero-emission pneumatic pumps are technically infeasible at sites without electricity"[359] are not compelling. One of the two cited comments simply states that "[z]ero-emissions pneumatic pumps are technically infeasible for our sites," due to lack of electricity, and that "[s]olar-powered pumps are not reliable for 24/7 operation in geographic locations that receive extended periods of cloud cover or snowfall,"[360] without providing any documentation or further arguments to support these claims. However, the evidence record shows that solar pumps have been shown to operate successfully in areas with harsh winter conditions, including the Wamsutter Basin in Wyoming,[361] and in fact zero-

[352] B.C. Reg. 282/2010, § 52.06.; Alberta Energy Regulator Directive 060, §8.6.1 (2).

[353] Datu Research, *supra* note 292, at 8.

[354] See 87 Fed. Reg. at 74770 ("In addition, some of the means of powering a pneumatic pump without the use of natural gas can also be used to power pneumatic controllers. While our updated BSER analyses for pneumatic pumps and pneumatic controllers evaluated the cost effectiveness of these sources independently, the shared usage of solutions for the two sources, such as compressed air systems, solar-powered systems, or generators, will result in even lower overall site-wide cost effectiveness values.").

[355] Pump Projects, *Instrument Air,* https://pumpprojects.com/products/instrument_air/ (last visited Feb. 12, 2023).

[356] 87 Fed. Reg. at 74772.

[357] *See also*, Rutherford et al., *Closing the methane gap in US oil and gas and natural gas emissions inventories,* 12 Nature Comms. (Aug. 5, 2021), https://www.nature.com/articles/s41467-021-25017-4; Marc Mansfield et al., *Storage Tank Emissions Pilot Project (STEPP): Fugitive Organic Compound Emissions from Liquid Storage Tanks in the Uinta Basin* (July 17, 2017), https://documents.deq.utah.gov/air-quality/planning/technical-analysis/DAQ-2017-009061.pdf; Lesley Fleischman et al., Clean Air Task Force, *Tank Emissions from Controlled Tanks*, https://www.epa.gov/sites/default/files/2017-11/documents/5._catf_tank_presentation_for_inventory_workshop_final.pdf (last accessed Feb. 10, 2023).

[358] *Id.* at 74775.

[359] *Id.* at 74772.

[360] Southern Ute Indian Tribe, Colorado, Comment Letter on Standards of Performance for New, Reconstructed, or Modified Sources and Emissions Guidelines: Oil and Natural Gas Sector Climate Review (Doc. ID No. EPA-HQ-OAR-2021-0317-0463) (Jan. 26, 2022) , https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-0463.

[361] TRIDO Solutions LLC, Comment Letter on Standards of Performance for New, Reconstructed, or Modified Sources and Emissions Guidelines: Oil and Natural Gas Sector Climate Review (Doc. ID No. EPA-HQ-OAR-2021-0317-0838) (Jan. 26, 2022), https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-0838.

emissions pumps are required for new pumps province-wide in Alberta and British Columbia, where snowfall, cloud cover, and winter insolation conditions are all more challenging for solar than in the contiguous United States. The second of the two cited comments does not make any specific claim about solar-powered pumps per se, but rather claims that onsite solar / battery systems designed to serve both non-emitting pumps and non-emitting pneumatic controllers are "uncommon [and] unreliable."[362] However, the evidence clearly shows that these systems are reliable, as EPA has found for controllers. Since the solar/battery technology that serves non-emitting pumps is the same as that which serves non-emitting controllers, EPA should recognize that concerns about the performance of these systems for non-emitting pumps are unfounded.

Finally, an exemption for sites without electricity would be incredibly difficult to monitor and could negate EPA's otherwise strong pump standard. As it stands, the exemption allows the venting of gas from up to three pumps at sites without electricity, and allows operators to self-certify with written statements that non-emitting options (solar powered pneumatic pumps and generators for compressed air systems) and routing to capture and control are infeasible at a given location. Fraudulent statements will be subject to civil and potentially criminal penalties.[363] However, because EPA provides no definition for "technical infeasibility" here or any guidance on how it would evaluate such claims, operators will have plenty of leeway to craft their own exemption from the standard in a way that may not be considered fraudulent. In this way, the self-certified exemptions will swallow the rule that EPA has determined is the BSER for sites with up to three pumps, but which do not have electricity, and the cumulative emissions resulting from pumps at these sites will continue to be significant and detrimental to the environment and people's health.

3. *If EPA retains the exemption for sites without electricity, it must narrowly tailor the exemption.*

Because non-natural gas driven options are available and cost-effective, we encourage EPA to narrowly tailor its tiered exemption for sites without electricity in a few critical ways, should the agency retain this exemption.

First, exemptions should not be available to operators that are converting a certain number of natural gas-driven controllers, and certainly all of these controllers, or who have installed a number of site-wide systems that power non-natural gas-driven pneumatics. Limiting the exemption based on the percent of controllers converted or the number of site-wide systems installed is practical. Zero-emission controllers and pumps can share the same equipment (such as air compressors, solar panels, batteries, etc.). When operators install instrument air compressors or install solar arrays, those technologies can be used to power both controllers and pumps. Additionally, EPA's proposal discusses the cost-effectiveness of applying solutions site-wide and acknowledges that pump cost-effectiveness increases when controllers are on-site, due to the usage of shared equipment[364] and our independent analysis demonstrates the cost-

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[362] Permian Basin Petroleum Assoc., *Comment on Standards of Performance for New, Reconstructed, or Modified Sources and Emissions Guidelines: Oil and Natural Gas Sector Climate Review* (Feb. 2, 2022) (Doc. ID No. EPA-HQ-OAR-2021-0317-0793), https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-0793.
[363] 87 Fed. Reg. at 74776.
[364] *Id.* at 74770.

effectiveness of site-wide zero-emitting solutions as well.[365] As a result, zero-emission pumps should be required at facilities that already have the necessary infrastructure in place, since doing so would both result in greater emissions reductions and would be feasible and cost-effective.

Second, EPA must also strengthen the technical infeasibility showing. Specifically, to qualify, operators should have to show that they cannot use *any* of the many zero-emission pump options – including electric, solar, instrument air, and routed pumps. We support EPA's proposed requirements for the feasibility showing for solar and instrument air,[366] but additionally would recommend the following: to demonstrate that use of electricity is infeasible, the operator must show that the relevant facility is in a remote location greater than 0.5 miles from the grid, as analyses show it is cost-effective to connect to the grid within that distance.[367] To demonstrate that the use of solar is infeasible, operators must show why certain technical issues exist, such as those associated with weather or temperature conditions. As EPA has proposed, operators should also need to show with specificity why routed pumps that achieve 100 percent capture are infeasible, and we support EPA's proposal for how operators would make that showing, including safety considerations, distance from a process, pressure losses, and other technical reasons.[368]

Finally, we recommend that upon an infeasibility showing, EPA require operators to use a control device at all sites, even at sites with fewer than four pumps. As EPA notes, control devices are site-wide technologies that would usually—if not always—be used to avoid venting from just four pumps.

4. *EPA's affected facility definition, and modification and reconstruction interpretations, are appropriate.*

EPA's proposal to change the affected facility definition to the collection of pumps at a site is appropriate for the same reasons outlined above regarding pneumatic controllers. Most mitigation solutions – including zero-emission power sources or control devices – are installed to cover large groupings of pumps (and usually controllers, too). Additionally, the affected facility definition should align with EPA's cost analysis – which is conducted using model plants – and operator practices that tend to calculate emissions site-wide rather than for individual pieces of equipment.

We also support EPA's interpretation of "modification" in this context. Like its proposal for controllers, EPA's proposal for pumps specifies that if one or more pneumatic pumps are added to the site such that the total number of pumps increases, that addition constitutes a modification because it represents a physical change that results in an increase in emissions and would result in application of OOOOb to the rest of the site's pumps. For the same reasons discussed above for pneumatic controllers, the addition of routed natural gas-driven pumps should trigger a modification. As with controllers, the fact that most mitigation solutions are site-wide supports that the appropriate affected facility definition should include the collection of pumps at a site.

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[365] Carbon Limits, 2021 Report, *supra* note 268.
[366] 87 Fed. Reg. at 74777.
[367] Analysis Group Report, *supra* note 269, at 24–26.
[368] *See* 87 Fed. Reg. at 74777.

Because both zero-emission and natural gas-driven mitigation technologies (including control devices and systems that route to process) are typically site-wide solutions, EPA's affected facility and modification definitions in this context are reasonable.

Finally, we support EPA's proposal to interpret "reconstruction" of a site as whenever greater than 50 percent of the existing onsite pumps are replaced[369] over a two-year period. Just as with pneumatic controllers, this definition for pneumatic pumps aligns with the statutory definition that reconstructed sources are those where the "fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility." EPA's interpretation is therefore appropriate, and we encourage the agency to clarify, as it should with controllers, that pumps that are part of replacement programs that commenced within the two-year period are included in the threshold determination.

F. Associated Gas from Oil Wells

In the supplemental proposal, EPA proposes a revised hierarchy of compliance options for associated gas from oil wells. EPA proposes three compliance options in addition to routing associated gas to a sales line: (1) using the gas as an onsite fuel source; (2) using the gas for another useful purpose that a purchased fuel or raw material would serve; and (3) reinjection into a well or injection into another well for enhanced oil recovery. one of the alternative uses listed above due to technical or safety reasons.[370] This demonstration would need to address the specifics regarding the lack of availability to a sales line, including efforts by the operators to acquire access to such a line or to facilitate alternative offsite transport and use of associated gas and show why all potential alternative uses are not feasible.[371]

EPA further proposes to require that the initial demonstration include "a detailed analysis documenting and certifying the technical or safety reasons" as to why implementing the BSER or any of the abatement alternatives is not feasible or safe.[372] EPA further proposes that operators obtain a certification by a professional engineer or other qualified individual when submitting an initial technical infeasibility demonstration.[373] Subsequently, an operator's annual report must include either a statement that 1) no change has been made at the site since the original certification that would impact the operator's ability to comply versus flare, or 2) if a change has been made since the original certification, a recertification of infeasibility or a statement indicating that compliance can be achieved and a description of how compliance will be achieved.[374] Operators must also include the start date, time, and duration of each instance of venting in their annual reports.[375]

Our comments below provide updated recommendations to further reduce flaring, in particular ongoing, continuous, (i.e. "routine") flaring of associated gas. While we strongly support EPA's revision of the hierarchy of the compliance standard and the removal of flaring as a compliance

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[369] *See id.* at 74771.
[370] *Id.* at 74779.
[371] *Id.* at 74780.
[372] Proposed 40 C.F.R. § 60.5377b(b)(1).
[373] 87 Fed. Reg. at 74779–80.
[374] Proposed 40 C.F.R. § 60.5420b(b)(4)(ii)(B).
[375] 87 Fed. Reg. at 74780.

option on par with the others, we urge EPA to take additional steps to address routine flaring, with a particular focus on two potential pathways to reduce this practice.

In section [1], we discuss emissions and health impacts from flaring.

In section [2], we recommend that EPA adopt a BSER that acknowledges the cost-effectiveness and availability of alternative options to routing to a sales line that EPA finds represent alternative uses of associated gas.

In section [3], we discuss the first pathway to reducing flaring. We recommend that EPA replace the broad technical infeasibility exemption with explicit, narrowly-defined exemptions that are available only for short-term, temporary (i.e., non-routine) flaring thereby helping to prevent routine flaring from new and existing wells. This recommendation builds on our prior comments, and we provide more detail concerning certain, time-limited instances in which temporary flaring may occur. We believe this first pathway presents the most protective, enforceable approach to reducing flaring.

In section [4], we discuss an alternative second pathway to reduce flaring. We suggest revisions to the certified technical infeasibility demonstration, including clarifying that "technical infeasibility" does not include economic infeasibility, but rather is limited to instances when it is physically impossible for an operator to implement one of the four gas recovery methods. We further recommend improvements to the certification requirement and process to ensure the reliability of the analysis contained in the technical infeasibility demonstration and to enhance the enforceability of the technical infeasibility exemption.

1. *Flaring and venting produce a significant amount of emissions and are detrimental to human health*

Flaring and venting contribute a significant amount of methane emissions annually. In 2019, flaring emitted 86,000 metric tons of methane and venting emissions emitted 68,000 metric tons of methane.[376] These estimates likely underestimate methane emissions from associated gas flaring and venting, as they do not account for observed high rates of unlit and malfunctioning flares, as discussed in Section IV.B

Studies also demonstrate that emissions from flaring and venting cause severe health burdens on communities, especially disadvantaged communities like low-income populations, people of color, the elderly, and children.

A 2023 study by Boston University's School of Public Health, The University of North Carolina, and Environmental Defense Fund has analyzed the impacts of onshore oil and gas flaring and venting on air quality and health.[377] Prior studies have indicated that oil and gas activity is associated with increased risk of adverse health events, but there was limited quantification of the health impacts that resulted from air pollution from flaring and venting activities. This study

[376] These are estimates based on data reported to the GHGRP for 2019.
[377] *See* Huy Tran et al., *Onshore Oil and Gas Flaring and Venting Activities in the United States and their Impacts on Air Quality and Health* (pre-publication slides) (Feb. 2023) (included as Attachment Q).

sought to fill this gap by quantifying ozone, PM2.5 and NO2 emissions from venting and flaring and attributing those emissions to particular health outcomes. Using a hybrid VIIRS and NEI based emissions inventory and applying CMAQ and BenMAP-R to assess air quality health impacts, the study found that in 2017, flaring and venting emissions from oil and gas operations resulted in 710 premature deaths, 73,000 asthma exacerbations among children, 210 instances of ozone NAAQS exceedances, and over $7.4 billion in health damages.[378] Critically, the study has found that these health impacts disproportionately burden disadvantaged populations. Of the adult deaths and child asthma exacerbations caused by venting and flaring, one in three are among low-income populations, and one in five are in communities home to Native American populations.[379] The study also looks at specific pollutant emissions and their impacts. It finds that flaring and venting contributes to 50% of VOC emissions from oil and gas facilities across the continental U.S., 63.1% in Texas, 84.6% in North Dakota, 52% in New Mexico, 70.6% in Colorado, and 58.8% in Wyoming. And that ozone (O3) pollution from flaring and venting contributes to 230 deaths, 9,700 asthma exacerbations, and 110 respiratory hospitalizations annually.[380]

The 2023 study results complement previously published literature, including a 2022 study by Rice University and Clean Air Task Force, which looked at the health impacts related to black carbon emissions from flaring in the U.S.[381] This study used satellite flaring data from VIIRS and three separate reduced form models to assess flaring health impacts. It estimated that flaring from oil and gas operations emitted nearly 16,000 tons of black carbon in 2019, leading to 26-53 premature deaths that were directly attributable to air quality associated with flares, mostly in Texas, North Dakota, and New Mexico.

Another analysis produced for this comment by Environmental Defense Fund also has focused on the impacts of flaring on disadvantaged communities living near oil and gas sites. To conduct this analysis, EDF used Enverus data to identify wells with reported flaring in 2019 (available for the following states: TX, NM, CO, ND, MT, WY and MS). By identifying wells with flaring, EDF was able to identify the local communities that are impacted by the air pollution from these wells. Using the methodology described in Proville et. al. 2022,[382] the US Census Bureau's American Community Survey 5-year estimates for 2015-2019,[383] and health data from the Centers for Disease Control and Prevention's Places dataset,[384] EDF was able to estimate the populations living within a half mile radius of the previously identified wells using areal apportionment.

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[378] *Id*. at 4–5.
[379] *Id*. at 5.
[380] *Id*. at 31.
[381] Chen Chen et al., *Black Carbon Emissions and Associated Health Impacts of Gas Flaring in the United States*, 13 Atmosphere 385 (Feb. 2022), https://www.mdpi.com/2073-4433/13/3/385/htm.
[382] Jeremy Proville et al., *The demographic characteristics of populations living near oil and gas wells in the USA*, 44 Population Env't. 1 (2022), https://doi.org/10.1007/s11111-022-00403-2 (Attachment R).
[383] U.S. Census Bureau, *2015–2019 American Community Survey 5-year Estimates* (2021) (retrieved from https://www2.census.gov/geo/tiger/TIGER_DP/2019ACS/).
[384] Centers for Disease Control and Prevention, *Places: Local Data for Better Health*, https://www.cdc.gov/PLACES/ (last visited Feb. 13, 2023).

From this analysis, EDF estimates there are roughly 240,000 people living within a half mile of a well with flaring. This includes approximately 19,000 children under the age of five, more than 28,000 older Americans over the age of 65, 110,000 people living in poverty, and almost 120,000 people of color, including 7,400 Native Americans and 94,000 Hispanic/Latinos. Because flaring data at the well level is only available for seven states, it is likely that these numbers are higher in reality. Several of these demographic groups are over-represented in the population living in proximity to flaring, relative to the nation at large. For example, Native Americans live near actively flaring wells at rates 80% higher than the national average. Nationally, Hispanic/Latinos make up about 20% of the overall population, but 40% of those living near a flaring well identify as Hispanic/Latino. Among those near flaring, asthma, chronic obstructive pulmonary disease (COPD), coronary heart disease (CHD), and stroke are found at rates 4-8% higher than the rest of the country. Roughly 17,000 adults with asthma, 13,000 adults with COPD, 12,000 adults with CHD, and 6,500 adults who have experienced a stroke live within a half mile of a flaring well.

These results comport with previous findings, including a 2021 study by researchers at UCLA and USC that found that more than half a million people in the U.S. live within a half mile of significant oil and gas flaring.[385] Of these people, the study found, 210,000 live near more than 100 flares, including a disproportionate number of black and indigenous people and other people of color.

These studies show the significant health impacts of flaring and that they disproportionately impact vulnerable communities. They highlight the critical need to address emissions from associated gas at oil wells. As noted in section I (A), EPA's proposal will reduce methane emissions from associated gas by roughly one million metric tons between 2023-2035. EPA standards could reduce associated gas methane emissions by an additional 400,000 tons (to at least 1.4 million tons)[386] over this period if strengthened as outlined below. Doing so will also substantially reduce the health impacts flaring has on local communities. Like flaring and venting emissions estimates, these emission reductions estimates are likely undercounted as they do not account for reductions that could be achieved by reducing unlit and malfunctioning flares.[387]

2. *The BSER for associated gas should include routing to a sales line and gas recovery for other uses*

Our comments on the 2021 proposal recommended EPA eliminate the harmful, polluting, and wasteful practice of routine flaring by determining that the "BSER for emissions from associated gas is to capture and sell, productively use or reinject the gas."[388] We further advocated for EPA to require operators to "capture and route emissions to a sales line, to use it on-site for a

[385] Lara J. Cushing et al., *Up in smoke: characterizing the population exposed to flaring from conventional oil and gas development in the contiguous US*, 16 Env't Rsch. Letters 034032 (Feb. 2021), https://iopscience.iop.org/article/10.1088/1748-9326/abd3d4.
[386] *See infra* section IV.A.
[387] *See infra*, section IV.B.
[388] 2022 Joint Environmental Comments, *supra* note 1, at 178.

productive purpose, or to preserve it through re-injection" and "carefully delineate when exemptions may apply."[389]

In both the November 2021 Proposal and the Supplemental Proposal, EPA determined the BSER for associated gas to be routing to a sales line.[390] However, in the Supplemental Proposal, EPA agreed that alternative uses of the associated gas should be allowed, "as these options are equivalent in terms of emission reduction to the identified BSER."[391] We recommend that EPA clarify that the BSER for associated gas includes routing to a sales line and other gas recovery options. Specifically, we recommend that the BSER includes the following four gas recovery options:

- Recover the associated gas from the separator and route the recovered gas into a gas gathering flow line or collection system to a sales line,
- Recover the associated gas from the separator and use the recovered gas as an onsite fuel source,
- Recover the associated gas from the separator and use the recovered gas for another useful purpose that a purchased fuel or raw material would serve, or
- Recover the associated gas from the separator and reinject the recovered gas into the well or inject the recovered gas into another well.

For the second option encompassing "onsite use," we urge EPA to clarify that the onsite use must be one associated with oil and gas production. This is to ensure that the use is one EPA is familiar with and has authority to regulate so that unintended venting does not occur from unpermitted or uncontrolled sources. One example where this can occur is cryptocurrency mining operations, discussed below.

For the third option encompassing use for "another useful purpose," we support EPA's interpretation encompassing emerging techniques that provide for an alternative use offsite, such as compressing gas and transporting it to a pipeline or processing plant.[392] However, we urge EPA to clarify that the use of associated gas for cryptocurrency mining operations does not qualify as a legitimate alternative use.[393]

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[389] *Id*. at 181.
[390] 86 Fed. Reg. 63110, 63237–38.
[391] 87 Fed. Reg. 74702, 74779.
[392] *Id.* at 74779.
[393] Operators in New Mexico and Colorado have attempted to use associated gas for this purpose. In reviewing requests to use associated gas in cryptocurrency mining operations, the New Mexico OCC has raised the following concerns: (1) cryptocurrency mining is a business venture separate and distinct from oil and gas production activities; (2) cryptocurrency mining activities are not within the scope of a typical oil and gas lease; (3) cryptocurrency mining will result in the introduction of equipment to the lease that OCC lacks the authority to regulate. N.M. Energy, Mineral and Natural Resources Dept., *Notice of Rule Interpretation: Waste Rule Beneficial Use Of Lost Gas For Purposes Of Natural Gas Management Plans And Monthly Reporting* (Sept. 6, 2022), https://www.emnrd.nm.gov/ocd/wp-content/uploads/sites/6/9-6-22-NOTICE-Waste-Rule-Interpretation-Beneficial-Use.pdf. The New Mexico OCC has determined that cryptocurrency mining do not constitute a beneficial use of associated gas because of these concerns. *Id.* An inspection of a cryptocurrency mining operation on an oil and gas location in Adams County Colorado revealed uncontrolled venting of natural gas from a produced water tank. A follow up inspection by the state revealed that the venting was "related to a malfunction where the generator engine

For the fourth option of reinjection/injection, we recommend that EPA remove any specific reference to "enhanced oil recovery." Other preferable options exist for injected or reinjected gas, such as permanent storage in porous geological formations, and there is no reason to disallow or subordinate these alternatives. The Rystad report, Attachment W to our prior comments, demonstrates that storage is available in all of the states primarily responsible for associated gas flaring, except for North Dakota. Notably, saline aquifers are an alternative potential for storage in North Dakota.[394]

Our prior comments provided detailed information regarding the cost-effectiveness and availability of these alternative options.[395] As we stated in our prior comments, "at least one or more of the best practices [including the compliance alternatives EPA proposes here] for gas capture and sale, productive use, or reinjection.. . . . .are broadly available to operators at a reasonable cost in every basin and at every production level."[396]

In the November 2021 Proposal, EPA proposed to find that cost-effectiveness values up to $1,970/short ton of methane reduced are reasonable. According to estimates by Rystad Energy, the costs of these gas recovery options per metric ton of methane abated are well below the levels that EPA finds cost-effective.

- *Routing to a sales line.* The Rystad report shows that connecting wells to gathering infrastructure is not only highly cost-effective but profitable for operators, with an average net profit to operators of $3.10 per thousand cubic feet (kcf) and average *negative* cost of $162 per metric ton of methane flaring avoided.[397] Operators will pay between $0.40 and $0.80 per kcf handled by third party processing and gathering, netting profit after gas sales of $2.70 to $3.50 per kcf.[398] This corresponds to a range of *negative $141-183 per metric ton of methane abated*.[399] Gathering is an effective and available option for sites flaring any amount of gas.[400]
- *Onsite use.* Rystad estimates that on average, onsite use of gas nets a profit of $8.60/kcf and $449 per MT of methane flaring avoided, after accounting for cost savings from fuel switching.[401] For a site producing 50 kcf per day of associated gas, costs associated with onsite power generation include between $1.90 to $2.20 per kcf for a small power generator and between $0.60 to $1.70 per kcf for gas treatment, netting between $7.70 to

went out of service but the fuel gas supply continued and was vented out of the top of the tank since it wasn't being consumed by the engine." Email from Craig Giesecke to Keith Huck (Jun. 28, 2022) (included as Attachment S). This is but one example of where use of associated gas to power equipment used to mine cryptocurrency could lead to venting.

[394] Rystad Energy, *Cost of Flaring Abatement*, at slide 67 (Jan. 31, 2022) [Hereinafter Rystad] (included in 2022 Joint Environmental Comments, *supra* note 1, as Attachment X).

[395] 2022 Joint Environmental Comments, *supra* note 1, at 185–89.

[396] *Id.* at 190.

[397] Rystad, *supra* note 394, at 11. Additional detail on Rystad's analysis illustrating how Rystad derived cost ranges is included in Rystad Energy, *Flaring Abatement Input Costs* (Attachment T).

[398] *Id*. at 45.

[399] *Id*.

[400] *Id*. at 40.

[401] Rystad, *supra* note 394, at 11.

$9.40 in profit per kcf.[402] This corresponds to a range of *negative $402-491 per metric ton of methane abated*.[403] Onsite use is an effective option for sites flaring a relatively small amount of gas (less than 100 kcf/day).[404]

- *Other beneficial use.* EPA categorizes CNG trucking as "another useful purpose."[405]Rystad's report finds that on average, compressed natural gas (CNG) trucking will cost operators $1.8/kcf, or $94 per metric ton of methane flaring avoided.[406] At a site producing 250 kcf per day of associated gas, costs associated with CNG include between $0.60 to $1.70 per kcf for gas treatment, $0.30 to $1.00 per kcf for compression, and $2.60 to $4.10 per for 200 miles of transportation, for a net cost after gas sales of between $0.10 to $3.40 per kcf.[407] This corresponds to a range of *$5 to $177 per metric ton of methane abated*.[408] CNG is an effective option for sites flaring more than 250 kcf/day of gas, and is scalable across a range of sites.[409]
- *Reinjection.* Reinjection for storage costs vary depending on various factors, but Rystad finds that on average, costs are $3.4/kcf, and $177 per metric ton of methane flaring avoided.[410] Costs associated with reinjection include between $0.20 and $0.60 per kcf for gathering and between $0.20 and $5.70 per kcf for storage, for a total cost between $0.40 to $6.30 per kcf.[411] This corresponds to a range of *$20 to $329 per metric ton of methane abated*. Reinjection is an effective option for sites flaring more than 350 kcf/day of gas.[412]

While EPA declined to quantitatively analyze these alternatives in the 2021 TSD, stating, "the site-specific variabilities associated with the application of these control options are significant,"[413] and did not include a quantitative assessment of non-flaring abatement options in the 2022 TSD, the Rystad cost analysis estimates discussed above, which are broadly applicable across basins, offer a pathway to assessing costs and emissions reductions.

EPA quantitatively analyzed the use of a combustion control device to abate emissions from associated gas venting at five model plants in the 2022 TSD.[414] Below, we summarize the capture options available for each of EPA's model plants based on average and maximum levels of venting. Additionally, as Rystad notes, associated gas from nearby well pads could be aggregated together to increase the applicability of capture options.[415] As discussed, all capture

[402] *Id*. at 50–51.
[403] *Id*. at 51.
[404] *Id*. at 40.
[405] 87 Fed. Reg. at 74702, 74779.
[406] Rystad, *supra* note 394, at 11.
[407] *Id*. at 56.
[408] *Id*.
[409] *Id*. at 40–41.
[410] Rystad, *supra* note 394, at 11.
[411] *Id*. at 69.
[412] *Id*. at 40.
[413] U.S. Env't Protection Agency, Background Technical Support Document for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG), at 13–5 (Oct. 2021) (Dkt. No. EPA-HQ-OAR-2021-0317) [hereinafter Initial TSD].
[414] Supplemental TSD, *supra* note 121, at chapter 6, attachment 7.
[415] Rystad, *supra* note 394, at 40.

options are highly cost-effective based on cost per metric ton of methane flaring abated (and are even more cost-effective if assessed as abatement options for uncontrolled methane *venting*).

Table 17: Capture Options Are Available for Each of EPA's Model Plants

MP No.	Ave Flow Venting (scfm)	Max Flow Venting (scfm)	Ave Flow Flaring (kcf/d)	Max Flow Flaring (kcf/d)	Pipeline Gathering (>0 kcf)	Onsite Use (<100 kcf)	CNG (>250 kcf)	Gas Reinjection (>350 kcf)
1	2	4	2.88	5.76	Ave, max	Ave, max	No	No
2	10	20	14.4	28.8	Ave, max	Ave, max	No	No
3	50	100	72	144	Ave, max	Ave Flow	No	No
4	250	500	360	720	Ave, max	No	Ave, max	Ave, max
5	1250	2500	1800	3600	Ave, max	No	Ave, max	Ave, max

3. *Recommended pathway to address routine flaring: requiring associated gas recovery with allowances for specific circumstances of temporary flaring and venting*

a. *EPA should define the BSER as associated gas recovery with allowances for specific circumstances of temporary flaring and venting*

EPA's current proposal permits using one of four gas recovery options to comply with its standard for associated gas at oil wells, and includes a technical infeasibility exemption from the standard. As discussed above, EPA should incorporate all four gas recovery options into the BSER. EPA should further define the BSER as recovery of associated gas to (1) route into a gas gathering flow line or collection system to a sales line, (2) use as an onsite fuel source, (3) use for another useful purpose that a purchased fuel or raw material would serve, or (4) reinject into the well or inject into another well, unless one of a set of clearly defined circumstances that would allow temporary flaring or venting applies. We discuss the particular circumstances in which temporary flaring or venting may be warranted in detail below in section IV.F.b.

The term "standard of performance" means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which the Administrator determines has been adequately demonstrated.[416] In designating the BSER, EPA must first identify the various "systems of emission reduction" that

[416] 42 U.S.C.S. § 7411.

have been "adequately demonstrated" for a given source category.[417] 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."[418] EPA must set the standard at a level that is "achievable"[419] but reflects the "maximum practicable degree" of "control[]."[420] Indeed, the Clean Air Act "requires that the standards [] maximize the potential for long term economic growth 'by reducing emissions as much as practicable.'"[421] Courts will generally uphold EPA's designation of the BSER so long as it is not "exorbitantly costly in an economic or environmental way"[422] or "unreasonable."[423]

There are a variety of "systems" to reduce emissions from associated gas at oil wells that EPA has assessed, including the system set forth in its November 2021 proposal that would have allowed flaring at a 95% combustion efficiency rate if access to a sales line was not available. Other potential systems include those implemented by states such as Colorado and New Mexico.

Of these systems, the "best" that has been "adequately demonstrated" after considering the "extent of emission reductions," "costs" and "technological innovation," among other factors, are those being implemented in Colorado and New Mexico. These regulatory frameworks prohibit the routine flaring of associated gas and restrict flaring and venting to a set list of circumstances. As in EPA's supplemental proposal, Colorado and New Mexico require operators to capture associated gas from oil wells and either route the gas to a sales line or put it to an alternative use. The alternative uses allowed in New Mexico largely overlap with those included in EPA's supplemental proposal and include, among other things, power generation on lease, liquids removal on lease, reinjection for underground storage, and other alternative uses approved by the division.[424] For wells that are not connected to a pipeline, Colorado similarly allows operators flexibility to use other options to capture gas including to generate electricity or to process the gas to recover natural gas liquids, without venting or flaring.[425]

A standard based on approaches like those adopted in Colorado and New Mexico, which clearly limits and delineates circumstances where temporary flaring would be permitted, represents the "best system" for several reasons. For one, it would require gas recovery but contain reasonable exemptions for temporary flaring during certain activities that may require flexibility to vent or flare. Thus, this system would "reduc[e] emissions as much as *practicable*"[426] and reflect the "maximum *practicable* degree of control."[427] The standard would permit technological flexibility

[417] *See, e.g.*, 83 Fed. Reg. at 65433–34 (expounding upon 42 U.S.C. § 7411(a)(1) and citing relevant cases, including *Sierra Club v. Costle*, 657 F.2d 298, 326, 343, 346–47 (D.C. Cir. 1981); *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)).
[418] 83 Fed. Reg. at 65433–34.
[419] *Id*.
[420] 116 Cong. Rec. at 42,385 (1970).
[421] *Costle*, 657 F.2d at 326.
[422] *Essex Chemical Corp.*, 486 F.2d at 433.
[423] *Costle*, 657 F.2d at 343.
[424] N.M. Code R. § 19.15.27.9.D.(5) (2023).
[425] 2 Colo. Code Regs. § 404-1-903.d.(3).(E).
[426] *See Costle*, 657 F.2d at 326 (emphasis added).
[427] *See* 116 Cong. Rec. at 42,385 (1970) (emphasis added).

by allowing the use of a multitude of abatement methods, including routing to a sales line, injection or reinjection, use as onsite fuel, or use for another alternative purpose. And, as EPA notes in its supplemental proposal, technological innovation could potentially bring to the forefront more abatement methods that are not currently identified. Finally, the costs of a capture standard, as discussed above, are reasonable, [428] cost-effective, and in some instances are even profitable for operators.

Finally, a system requiring capture using different technologies with allowances for temporary flaring or venting under certain circumstances has been "adequately demonstrated." Colorado, for example, passed its regulations after a lengthy stakeholder and rulemaking process. Numerous operators, including the largest producers in the Denver-Julesburg Basin – PDC Energy Inc. and Occidental Petroleum Corporation – participated in the rulemaking, as did the Colorado Oil and Gas Association, the Small Operator Society, and API. The three largest producers in the Denver-Julesburg Basin expressed "general support" for the COGCC proposed rules and several noted that they shut in production facilities rather than flare or vent during instances of reduced gathering line pressure or limited takeaway capacity.[429] None of these producers objected to the rule's prohibition on routine flaring or venting. Rather, their comments were limited to ensuring that the COGCC rules did not prohibit flaring or venting allowed by the Air Pollution Control Division.[430] And no party challenged the adoption of the rules once promulgated.

Further, to date, the COGCC has granted only one variance from the prohibition on routine venting and flaring contained in R.903.(d)(3).[431] Similarly, New Mexico's standards were developed during a lengthy stakeholder and rulemaking process that included input from the New Mexico Oil and Gas Association and OXY USA, and no party challenged the adoption of the rules once promulgated. Operator support for a standard that requires capture with narrow exemptions, the absence of challenges to the rules, and the minimal variances that have been granted in Colorado are evidence of the reasonableness of these measures.

Operator practice also has shown such a standard is adequately demonstrated. Exxon, for example, has halted all routine flaring in the Permian Basin.[432] The Rystad report notes that most operators in Texas, North Dakota, New Mexico, Wyoming, and Colorado report low flaring

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[428] *See Costle*, 657 F.2d at 343.

[429] Response of PDC Energy, Inc. to 900-Series Prehearing Statements, at p. 2, In the Matter of the Changes to the Rules and Regulations of the Oil & Gas Conservation Commission of the State of Colorado, Docket No. 200300071 (2020), https://drive.google.com/drive/u/0/folders/1VOozq1I7HYNRsH52mS3oyyoPbIumdZb2; Response of Occidental Petroleum Corporation to 900-Series Prehearing Statements, at p. 2, In the Matter of the Changes to the Rules and Regulations of the Oil & Gas Conservation Commission of the State of Colorado, Docket No. 200300071 (2020), https://drive.google.com/drive/u/0/folders/1hwQ9sjx9rkyL8V9HXvZn7GbnwhqKJ5N6; Response of Noble Energy, Inc. to 900-Series Prehearing Statements, at p. 1, In the Matter of the Changes to the Rules and Regulations of the Oil & Gas Conservation Commission of the State of Colorado, Docket No. 200300071 (2020), https://drive.google.com/drive/u/0/folders/1hA1n8n0zvLSE0U-UPED20pVQz-KJeRCf.

[430] Response of Noble Energy, Inc. to 900-Series Prehearing Statements, *supra* note 429, at 3; Response of PDC Energy, Inc. to 900-Series Prehearing Statements, *supra* note 429, at 1.

[431] Colo. Oil & Gas Conservation Comm. (COGCC) Order, Williford Resources, LLC, Docket No. 210100008 (Apr. 20, 2022) (Attachment U).

[432] Sabrina Valle, *Exclusive: Exxon halts routine gas flaring in the Permian, wants others to follow* (Jan. 24, 2023), https://www.reuters.com/business/energy/exxon-halts-routine-gas-flaring-permian-wants-others-follow-2023-01-24/.

volumes.[433] Those operators that have reduced flaring have done so through "a change in mindset from viewing flaring as a part of normal operations to viewing flaring as a *constraint* on operations."[434]

Because a standard that requires capture with a narrow set of exemptions is cost-effective, would reduce emissions to the greatest extent practicable, and has been adequately demonstrated, EPA should consider it to be the best system of emission reduction.

b. Replace the "technical infeasibility" exemption with clearly delineated circumstances for temporary flaring

We strongly support EPA's exclusion of flaring as a compliance option for reducing associated gas from oil wells. But while flaring is no longer a compliance options, operators nonetheless can flare if they demonstrate that each of the gas recovery options is not technically feasible or safe. This is true for operators of new and existing wells. Moreover, EPA does not propose to limit the volume or amount of time an operator can flare upon submission of its technical infeasibility demonstration. We describe our concerns with the technical infeasibility exception below. In particular, we urge EPA to revise the standard to limit the instances when an operator may flare temporarily by replacing the proposed technical infeasibility exemption with a set of clearly delineated circumstances in which temporary flaring or venting may be warranted.

i. The technical infeasibility exemption is overly broad and presents enforcement challenges

The technical infeasibility exemption, as proposed, does not distinguish between instances when an operator seeks to flare on a routine, ongoing basis and those instances when an operator seeks to flare on a temporary basis. This is one example of the over-breadth of the exemption. As these and our prior comments demonstrate, ongoing, routine flaring is rarely, if ever, a necessary part of operations. Furthermore, the technical infeasibility exemption presents enforcement challenges. Below we describe the reasons why this exemption is overly broad.

First, safety concerns are by their nature temporary and would never give rise to the need to flare indefinitely. EPA should therefore require that any safety-related flaring cease when the safety concern no longer exists.

Second, routine flaring from new wells can never be justified due to the technically infeasibility of some alternative. As discussed in both the Rystad report and the expert report of Tom Alexander, routine flaring is readily preventable at new wells with proper planning and coordination between upstream and midstream operators.[435] The Rystad report makes clear that the main drivers of flaring are timing of well hookups and infrastructure capacity.[436] An operator has complete control over decisions regarding where and when to drill a new well and when to

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[433] Rystad, *supra* note 394, at 100
[434] *Id.* at 80.
[435] Thomas Alexander, Alexander Engineering, *Expert Report of Thomas Alexander* 2 (2023) [hereinafter, *Expert Report of Thomas Alexander*] (Attachment V).
[436] Rystad, *supra* note 394, at 8 (noting that Infrastructure capacity constraints account for 84 percent of flaring in ND and 62 percent of flaring in TX).

complete or put such a well into production.[437] As such, operators of new wells have the ability to address both timing and infrastructure capacity challenges.

Third, routine flaring from existing wells is also avoidable or preventable.[438] In the event an existing well is not currently connected to a gathering line, cost-effective options in addition to routing to a gathering line are available, including converting the associated gas to CNG, using it to replace a different fuel source for onsite fuel purposes, converting the gas to electricity, or injection or reinjection.[439] Prudent operators are prepared for events that can result in loss of takeaway capacity such as midstream and downstream interruptions, changes in gas composition requirements, and changes in line pressure.[440] Such operators can quickly employ one of the alternative abatement options EPA proposes here.[441]

In the event an operator loses its connection to a gathering line without warning due to events outside its control, a limited exception for flaring during the upset condition can address an operator's need to flare temporarily (discussed further below).[442] Operators can also temporarily shut in wells if time is needed to restore access to a pipeline or make arrangements for alternative gas recovery. Shutting in wells does not necessarily harm the productivity of a well and may, in some instances, enhance performance.[443] Additionally, the section 111(d) implementation process as proposed gives operators of existing wells significant time (i.e., approximately four-and-a-half years after rule finalization) to implement one of the four approved alternative uses for associated gas. In those rare instances when an operator of an existing well is unable to capture, put to beneficial use, or inject or reinject associated gas after this lengthy runway due to truly unique and extenuating circumstances, it may request a variance in a state plan pursuant to the RULOF provisions discussed earlier in these comments.

Fourth, the exemption presents enforcement challenges. While an operator's demonstration of technical infeasibility must be signed and certified as to its truth, accuracy, and completeness, there is no requirement that EPA review and approve this demonstration prior to an operator flaring. Rather, operators must retain records of the certified demonstration and provide it to EPA as part of annual reporting. This raises the possibility that flaring will occur in the absence of a full, accurate, complete, or otherwise adequate demonstration.[444] In order for EPA to identify any problems or shortcomings in the certified demonstration, it must review the operator's documentation, but this review will necessarily occur after an operator has flared, potentially for a considerable amount of time. This opens the door to extended periods of flaring in violation of the rules.

[437] 2022 Joint Environmental Comments, *supra* note 1, at 187, 194.
[438] *Expert Report of Thomas Alexander*, *supra* note 435, at 4.
[439] 2022 Joint Environmental Comments, *supra* note 1, at 187; *Expert Report of Thomas Alexander*, *supra* note 435, at 4.
[440] *Expert Report of Thomas Alexander*, *supra* note 435, at 4.
[441] *Id.*
[442] *Id.* at 4–5.
[443] *Id.* at 3.
[444] *Id.* at 6–7.

ii. Specific, narrowly-defined circumstances when flaring may occur

Rather than include a technical infeasibility exemption, we recommend that EPA require oil wells to capture associated gas by utilizing one of the four recovery options, except in specific, narrowly-defined circumstances when a well may be permitted to flare on a temporary basis. In doing so, EPA can follow the approach taken by Colorado and New Mexico to address routine flaring. Both of these states prohibit venting or flaring other than in enumerated exceptional situations. EPA can apply these exemptions nationally because "[t]he types of reservoir traps, reservoir drives, subsurface geology, structures, production technologies, infrastructure buildouts, availability of services and supplies are all very similar across producing areas."[445] A time-limited or otherwise narrow exemption to utilizing one of EPA's approved gas recovery options may be justified in the following circumstances, each discussed in more detail below: upset conditions; pipeline, equipment, or facilities commissioning; initial production where gas does not meet pipeline specifications and where an operator is connected to a gathering line; active and required maintenance; production evaluation and production tests; Bradenhead monitoring; and packer leakage tests.[446]

To assist with compliance and enforcement, we suggest that EPA require that operators maintain records of the date, cause, estimated volume of gas flared or vented, and duration of each event it seeks to justify under one of the exemptions.[447] Below, we discuss circumstances where EPA may consider exemptions from its capture requirements in which flaring is authorized.

Upset Conditions

Capture may be technically infeasible or unsafe for a limited amount of time during upset conditions, which are emergency circumstances outside of the control of an operator that can interrupt its ability to comply with the proposed standard. An example of an upset condition is a temporary, unplanned loss of connection to, or ability to route gas to, a gathering system. EPA has determined that interruptions of an operator's ability to route gas to a gathering system constitute a technical or safety reasons that can justify flaring.[448] It is critical that EPA permit only temporary flaring during these circumstances and establish clear time limitations during which it may be permitted.

Both Colorado and New Mexico allow operators to flare or vent gas for a short period of time during upset conditions or emergencies, including temporary unavailability of access to a gathering line. The Colorado rules provide a concise, clear definition of this circumstance, while also limiting the length of time an operator may flare or vent during such circumstances. Colorado's definition of an "Upset Condition" is "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."[449] Notably, per the Statement of Basis and Purpose for the rule, this definition does not include "an operator's

[445] *Id.* at 3.
[446] *Id.* at 4–6.
[447] *See e.g.*, 2 Colo. Code Regs. § 404-1-903.d.(2) (2023).
[448] 87 Fed. Reg. at 4780.
[449] 2 Colo. Code Regs. § 404-1-100-21 (2023).

negligence, failure to install appropriate equipment, or failure to perform scheduled maintenance."[450]

Furthermore, Colorado limits venting and flaring during upset conditions to a period necessary to address the upset, not to exceed 24 cumulative hours, and requires operators to maintain records of the date, cause, estimated volume of gas flared or vented, and duration of each upset condition.[451] Per the Statement of Basis and Purpose for the rule, Colorado's definition of an upset condition also include *sudden* lack of pipeline capacity.[452] Accordingly, Colorado allows operators to vent or flare associated gas in the event that unplanned disruptions to a gathering system interrupt the ability of an operator to route associated gas to a sales line, but only up to 24 cumulative hours.

New Mexico similarly allows for temporary venting or flaring during an emergency. An emergency means "a temporary, infrequent, and unavoidable event in which the loss of natural gas is uncontrollable or necessary to avoid a risk of an immediate and substantial adverse impact on safety, public health, or the environment" other than in certain exceptions.[453] One such exception is "venting or flaring of natural gas for more than eight hours after notification that is caused by an emergency, an unscheduled maintenance, or a malfunction of a natural gas gathering system."[454] In other words, an upstream operator may vent or flare during a temporary, infrequent, and unavoidable event involving loss of connection to a sales line provided the midstream operator notifies the producer of the disruption to the operator of the sales line. However, an upstream operator cannot vent longer than 8 hours in this circumstance.[455]

We recommend EPA limit flaring or venting during an upset condition to not more than 24 cumulative hours, in line with the Colorado rules. This would apply in those instances where a disruption to a gathering system or other event causes an interruption to an operator's ability to route the gas to a sales line. Prudent operators should be prepared to recover gas in the event of sudden loss of takeaway capacity.[456] Specifically, while short-term flaring may be necessary to allow the operator to make alternative arrangements for the disposition of associated gas, prudent operators can quickly deploy alternative uses of the gas such as onsite use, compression for CNG, or injection.[457] Because of this we do not believe EPA should include a separate exemption for loss of takeaway capacity that would permit flaring or venting in excess of 24 hours.

Pipeline, Equipment, or Facilities Commissioning

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[450] Colo. Oil & Gas Conservation Comm., Statement of Basis, Specific Statutory Authority, and Purpose: New Rules and Amendments to Current Rules of the Colorado Oil and Gas Conservation Commission, 800/900/1200 Mission Change Rulemaking at 76, (Dkt. No. 200600115), https://www.emnrd.nm.gov/ocd/wp-content/uploads/sites/6/800-900-1200MissionChangeDraftSBP.pdf [hereinafter Colo. 800/900/1200 SBP].
[451] 2 Colo. Code Regs. § 404-1-903.(d)(1)(A) (2023).
[452] Colo. 800/900/1200 SBP, *supra* note 450, at 76.
[453] N. M. Code R. § 19.15.27.7.H (2023).
[454] *Id.* § 19.15.27.7.H.(4).
[455] *Id.* § 19.15.27.8.E.(8).
[456] *Expert report of Thomas Alexander, supra* note 435, at 4.
[457] *Id.*

Another circumstance that may give rise to an operator's need to flare on a temporary basis is the commissioning of pipelines, equipment, or facilities.[458] New Mexico allows operators to flare temporarily during these circumstances,[459] and even then "only for as long as necessary to purge introduced impurities."[460] An operator may need to flare temporarily when it is first connecting to a pipeline that has just been constructed if the pipeline was cleaned out with substances that the midstream operator does not want in the gas.[461] With proper coordination between midstream and downstream operations, operators can substantially mitigate any lost production of oil and avoid unnecessary flaring of associated gas.[462] If carefully applied, this limited exemption will not give rise to significant emissions; "flaring during this exemption will often be of very short duration," since it does not take long to "clear impurities from equipment, facilities or pipelines."[463]

Initial Production Where Gas Does Not Meet Pipeline Specifications and Where an Operator is Connected to a Gathering Line

Operators may also need to flare temporarily where an operator is connected to a sales line, but natural gas does not meet pipeline specifications and the other three gas recovery options are also unavailable.[464] This occurs where impurities such as oxygen or nitrogen are present in the associated gas and thus the gas cannot safely be sent to the sales line.[465]

New Mexico requires the operator take specific steps to limit flaring during this circumstance. Operators must analyze gas samples twice a week to determine if pipeline specifications have been achieved, and must route gas into gathering pipelines when pipeline specifications are met.[466] Operators must also provide pipeline specifications and gas analyses to the agency upon request.[467]

The amount of time an operator may need to flare in order to clean up associated gas prior to routing to sales should be short, with the specific timeframe varying depending on the reservoir characteristics and composition of the hydraulic fracturing fluid. On average, an operator may need to flare for as little as two days to a week.[468] Requiring an operator to take frequent samples of gas composition is imperative so that it can begin routing gas to sales as quickly as possible once impurities have been removed. The New Mexico requirement that operators sample twice a week is quite reasonable, and prudent operators will likely sample more frequently since there is a profit incentive to doing so.[469]

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[458] *Id.* at 5.
[459] N.M. Code R. § 19.15.27.8.D.(4)(m) (2023).
[460] *Id.* § 19.15.27.8.D.(4)(m).
[461] *Expert report of Thomas Alexander*, *supra* note 435, at 5.
[462] *Id.*
[463] *Id.*
[464] *Id.* at 6-7; N.M. Code R. § 19.15.27.8.D.(4)(l) (2023).
[465] *Expert report of Thomas Alexander, supra* note 435, at 6–7.
[466] N.M. Code R. § 19.15.27.8.D.(4)(l) (2023).
[467] *Id.*
[468] *Expert report of Thomas Alexander*, *supra* note 435, at 5.
[469] *Id.*

Active and Required Maintenance

Both Colorado and New Mexico allow for temporary venting and flaring during active and required maintenance activities. Colorado specifies that maintenance must both be active and required, clarifying that "while venting can be permitted while the maintenance activity is ongoing (for example, while personnel are on-site and performing the maintenance), venting during periods between discovery of the need for maintenance and the performance of the maintenance remains prohibited."[470] Colorado also requires operators to use best management practices to minimize venting during maintenance and repair activity, and Colorado is currently phasing in requirements that midstream operators capture hydrocarbons from blowdowns of compressors and other equipment at compressor stations and gas processing plants[471] - once fully phased in, Colorado midstream operators may no longer flare gas from depressurization of equipment for routing maintenance. New Mexico similarly allows venting or flaring during repair and maintenance, including blowing down and depressurizing production equipment to perform repair and maintenance.[472]

We recommend that EPA allow flaring during active and required maintenance activities, which includes blowing down and depressurizing production equipment.[473]

Production Evaluation and Production Tests

Colorado and New Mexico both allow for temporary flaring during production tests and production evaluations. Colorado defines a "Productivity Test" to mean "a test for determination of a reservoir's ability to produce economic quantities of oil or gas."[474] The state in turn defines a "production evaluation" as "an evaluation of production potential for determination of requirements for infrastructure capacity and equipment sizing."[475] Colorado allows venting or flaring during both of these events, but only subject to pre-approval. If the operator has obtained approval, the rules permit venting or flaring for a period not to exceed 60 days.[476] New Mexico limits venting or flaring during a production test for a period not to exceed 24 hours absent approval for a longer test period.[477]

We recommend EPA allow flaring during production and evaluation tests but limit the duration of these emissions events to 24 hours, as New Mexico has done, unless the operator obtains pre-approval to flare for a longer period of time. There may be instances, based on reservoir characteristics and the amount of knowledge an operator has about the reservoir's productivity, that an operator may need to flare for longer than 24 hours,[478] but in no event should flaring during this exemption exceed 60 days.[479]

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[470] Colo. 800/900/1200 SBP, *supra* note 450, at 84.
[471] 5 Colo. Code Regs. 1001-9-D-II.H.
[472] N.M. Code R. § 19.15.27.8
[473] *Expert report of Thomas Alexander*, *supra* note 435, at 5–6.
[474] 2 Colo. Code Regs. § 404-1-100–15.
[475] 2 Colo. Code Regs. § 404-1-100-14.
[476] 2 Colo. Code Regs. § 404-1-903.d.(1)(C).
[477] N.M. Code R. § 19.15.27.8.D.(4)(k) (2023).
[478] *Expert report of Thomas Alexander*, *supra* note 435.
[479] Datu Research, *supra* note 292, at 8.

iii. Specific circumstances where venting may be warranted

Venting may be necessary for safety as we have previously acknowledged.[480] In addition, operators may need to vent for a very brief period of time during downhole monitoring activities, namely when monitoring the downhole pressure during bradenhead monitoring and packer leakage tests. Both Colorado and New Mexico allow operators to vent or flare during bradenhead monitoring.[481] Colorado limits bradenhead monitoring to 30 minutes.[482] New Mexico also allows operators to flare or vent during packer leakage tests.[483] [484]

4. *Alternative pathway to address routine flaring: EPA should limit the applicability of the technical infeasibility exemption and bolster the requirements for the certified technical infeasibility demonstration.*

As discussed above, we have considerable concerns with the proposed technical infeasibility exemption and accompanying infeasibility demonstration. However, should EPA retain a technical infeasibility exemption, the agency must improve the rigor and enhance the enforceability of the exemption by: (1) limiting flaring to instances of physical impossibility; (2) requiring pre-approval of any flaring occurring under the technical feasibility exemption, or at least public notification of such flaring; (3) requiring that an independent third party submit the technical infeasibility certification; (4) requiring operators to submit detailed, certified technical infeasibility documentation at least annually if they intend to flare; and (5) require additional records of flaring events.

a. Physical impossibility must be the standard for routine flaring

As discussed above, we do not believe there are ever any instances where an operator must flare routinely due to technical infeasibility or safety. As such, we recommend that EPA prevent pollution from routine flaring by requiring gas recovery except in the temporary, limited circumstances discussed above. However, if EPA nonetheless finalizes a technical infeasibility exemption that allows an operator to flare based on a certified demonstration of technical infeasibility, the agency must limit the exemption by clearly delineating the "technical" reasons that would justify flaring in lieu of the four gas recovery options.

First, EPA must make clear that a demonstration based on a claim that the four abatement options are not economical at a particular site is not sufficient or relevant. EPA has not proposed an exemption based on economic infeasibility. As discussed above, the gas recovery options are cost-effective at a variety of sites. EPA clarifies elsewhere (e.g., in its well completion

[480] 2022 Joint Environmental Comments, *supra* note 1, at 181 (acknowledging that venting may occur during emergencies).
[481] N.M. Code R. § 19.15.27.8.D.(4).(i).
[482] Colo. 800/900/1200 SBP, *supra* note 450, at 86.
[483] N.M. Code R. § 19.15.27.8.D.(4).(j).
[484] *Expert report of Thomas Alexander, supra* note 435, at 6.

requirements) that technical infeasibility does not include economic infeasibility, but rather is limited to circumstances like lack of infrastructure, engineering issues, and safety concerns.[485]

Second, EPA must require operators to demonstrate the physical impossibility of each of the gas recovery options in order to claim the exemption to flare. We include potential physical impossibility demonstrations below for each abatement method.

Gathering Lines. In order to claim that routing associated gas to sales lines is not technically feasible, an operator should be required to show that it is physically impossible to connect to a gathering line and that the operator used best efforts to do so. Thus, for example, constraints that can be overcome with timing considerations (e.g., delaying completion or production of wells), compression (e.g., adding compressors to boost low-pressure gas in order to add the gas to higher-pressure pipelines) or proper planning are not sufficient to demonstrate that access to a gathering line is technically infeasible.[486] In these instances, lack of access to a gathering line is technically feasible because it is physically possible to route gas to the line with some timing revisions or the addition of compression at the well site.

Another Useful Purpose. To demonstrate that it is not technically feasible to use gas for another useful purpose that a purchased fuel or raw material would serve, such as conversion of associated gas to CNG, an operator must show that it is physically impossible to use the gas for another useful purpose. CNG transport services are widely available[487] and must be considered as another potential useful purpose in all flaring demonstrations. To demonstrate this option is not technically feasible an operator must show that it is physically impossible to convert associated gas to CNG at the wellsite due to physical or technical constraints and/or that CNG transport in the region is not available.

Onsite Fuel. An operator must show that there is no way to use the associated gas as an onsite fuel source to demonstrate that this abatement option is technically infeasible. As our prior comments demonstrated[488] operators have options for using associated gas as an onsite fuel source, including use for onsite power needs (e.g., replacing diesel with associated gas) or using associated gas to power a small electricity generation plant that sends power to the grid. Thus, an operator would need to demonstrate that neither option is available either because an operator has no onsite power needs or power needs have been met with less gas than produced, there is insufficient associated gas to support a small electricity generation plant, or there is no local demand for the power, even if generated.

Reinjection. To demonstrate that reinjection is technically infeasible, an operator must demonstrate that there is no subsurface reservoir or other storage available for reinjection. Porous subsurface reservoirs are readily available in all states responsible for the majority of associated

[485] U.S. Env't Protection Agency, *Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources, Final Rule*, 81 Fed. Reg. 35824 (June 3, 2016), https://www.govinfo.gov/content/pkg/FR-2016-06-03/pdf/2016-11971.pdf.
[486] *See e.g.*, *Expert report of Thomas Alexander*, *supra* note 435, at 7 (discussing efforts in North Dakota to find innovative methods of transporting oil to market in the absence of sufficient oil pipeline capacity).
[487] 2022 Joint Environmental Comments, *supra* note 1, at 187.
[488] *Id*. at 189.

gas flaring, with the possible exception of North Dakota.[489] There is potential, however, for reinjection into saline aquifers in North Dakota.[490]

b. Requiring pre-approval of flaring

EPA should require pre-approval of requests to flare based on claims of technical infeasibility. Doing so would enhance oversight and reduce abuse that could otherwise occur without pre-approval.

In Colorado, operators may flare gas during completion operations with specific written approval of the operator's gas capture plan.[491] Alternatively, the operator may submit a form which explains why flaring is necessary to complete the well and will minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources; estimates the anticipated flaring volume and duration; and explains its plan to connect the facility to a gathering line or otherwise utilize the gas in the future. The operator's plan may be approved, through a form requesting permission to flare during completion, if it is determined that the flaring is necessary to complete the well and the operator will minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.[492] In addition, Colorado requires pre-approval and documentation supporting the request for flaring in the event that an operator loses access to a gathering line.

In either instance, EPA should require public disclosure of flaring activities. Colorado requires notification of planned flaring, no later than two hours before flaring, as well as subsequent (and no later than 12 hour) notice of flaring due to upset conditions.[493] New Mexico requires notice of venting or flaring exceeding 50 MCF resulting from an emergency or malfunction, or that lasts eight hours or more within a 24-hour period.[494]

c. EPA should require certification by an independent third party and clarify potential enforcement actions for submission of fraudulent certification

We recommend that EPA require certification by an independent third party. EPA has proposed to allow certification by either a professional engineer or a "qualified individual with expertise in the uses of associated gas."[495] Notably, per EPA's proposal, an operator could use an in-house engineer, other qualified individual, or a contractor. However, there is no requirement that such individual be independent from the operator. Certification by an independent third party, rather than a professional engineer or a "qualified individual with expertise in the uses of associated gas," either of whom could be an in-house individual or a person with significant ties to the

[489] Rystad, *supra* note 394, at 67.
[490] *Id.* at 67; *Expert report of Thomas Alexander, supra* note 435, at 7.
[491] 2 Colo. Code Regs. § 404-1-903.C.(3).
[492] *Id*.
[493] 2 Colo. Code Regs. § 404-1-903.a.(1),(2).
[494] N.M. Code R. § 19.15.27.8.G.(1) (2023).
[495] Proposed 40 C.F.R. § 60.5377b(b)(2).

company, will enhance the credibility and reliability of the report.[496] Certification by an independent third party of all demonstrations seeking a flaring exception is necessary to ensure a robust, complete, and accurate demonstration of the reasons underlying the flaring request.

EPA should further clarify that both the certifier and the owner/operator may be subject to penalties for submission of a fraudulent or significantly flawed certification. This clarification is consistent with EPA's proposal for pneumatic pumps. EPA proposes to include a technical infeasibility exemption from the zero-emission pneumatic pump standard, provided an operator submits a demonstration certified by a qualified professional engineer or in-house engineer with relevant experience.[497] EPA notes that it "is committed to ensuring that this technical infeasibility provision is not abused or used as a loophole . . .," pointing to the potential for enforcement actions to be levied against both the owner/operator and certifier upon submission of a "fraudulent, or significantly flawed" certification.[498] We urge EPA to clarify that this same potential penalty is applicable to the submission of "fraudulent, or significantly flawed" certifications in the context of associated gas at the affected well facility, if EPA retains the technical infeasibility exemption.

d. *Operators must be required to submit a certified, thorough analysis of the technical feasibility of all gas recovery options each year if they intend to flare*

Operators seeking to routinely flare must submit a thorough analysis and engineering certification comparable to the initial certification each year. This demonstration should include the same information as the initial demonstration, namely a detailed analysis documenting the technical infeasibility or safety reasons for the infeasibility and an explanation as to why none of the four gas recovery options are technically feasible or safe. This demonstration must also be certified by an independent third-party.

e. *EPA should require records and reporting of flared amounts*

Finally, we recommend additional recordkeeping and reporting requirements to bolster the enforceability of the demonstration and prevent abuse of the exemption. These recommendations are based on requirements in Colorado[499] and New Mexico.[500] Specifically, we recommend that operators' initial and annual demonstrations include an estimate or measurement of the volume and content of vented or flared gas. This information should also be provided in the operator's annual report. As Colorado regulators have found, requiring records of the estimated duration and time of flaring helps prevent abuse and enhances enforcement.[501] Flaring data should also be publicly disclosed.

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[496] Maureen Lackner & Kristina Mohlin, Env't Def. Fund, *Certification of Natural Gas With Low Methane Emissions: Criteria for Credible Certification Programs* 11 (2022), https://blogs.edf.org/energyexchange/files/2022/05/EDF_Certification_White-Paper.pdf (Attachment W).
[497] 87 Fed. Reg. at 74776.
[498] *Id.*
[499] 2 Colo. Code Regs. § 404-1-903.d.(2) (2023).
[500] N.M. Code R. § 19.15.27.8.G.(2) (2023).
[501] Colo. 800/900/1200 SBP, *supra* note 450, at 78.

G. Well Completions

We support EPA's efforts to reduce venting and flaring during well completions, but we reiterate our concerns that the current proposal could allow operators to avoid meaningful reductions by claiming technical infeasibility to vent or flare.[502] In our 2021 comments, we urged EPA to prohibit venting unless (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."[503] Here, EPA declines to make changes to the current well completion requirements, other than two clarifying changes with respect to the requirements for wildcat, exploratory, and low-pressure well affected facilities.[504] We reiterate the request to improve the protectiveness of the well completion standards for all types of wells, consistent with our 2021 comments.

A review of GHGRP data provided in the table below indicates that 76% of emissions from well completions and workovers is due to venting. This information demonstrates that there is a need to further limit venting from well completions and workovers. Our comments in this section indicate two ways EPA can cost-effectively reduce venting during completions by prohibiting venting during the initial flowback stage and removing the technical infeasibility exception for the separation flowback stage.

1. EPA should follow the lead of New Mexico and Colorado and prohibit venting during the initial flowback stage of completions

As our prior comments discussed, EPA has the opportunity to further reduce emissions from oil and gas affected facilities by adopting state practices, and we urge EPA to follow the example set by Colorado and New Mexico, which require control of venting during initial flowback.[505] Doing so is technically feasible and safe, as illustrated by these two states' rules and expert testimony provided during the New Mexico hearing. Colorado requires flowback be routed to an enclosed flowback vessel device that achieves "a hydrocarbon control efficiency of at least 95%" or to a combustion device with "a design destruction efficiency of at least 98% for hydrocarbons."[506] New Mexico similarly requires operators to "collect and control emissions from each flowback vessel..." and route emissions to a control device that achieves a hydrocarbon control efficiency of at least 95%.[507] Operators must ensure that the control device "operates as a closed vent system...and that unburnt gas is not directly vented to the atmosphere."[508]

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[502] 2022 Joint Environmental Comments*, supra* note 1, at 179.
[503] 2022 Joint Environmental Comments*, supra* note 1, at 179.
[504] 87 Fed. Reg. at 74782.
[505] 2022 Joint Environmental Comments*, supra* note 1, at 178–81.
[506] 5 Colo. Code Regs. § 1001-9-D-VI.D.1.a. (2023).
[507] N.M. Code R. § 20.5.20.127.B.(1) (2023).
[508] *Id.* § 20.5.20.127.B.(1)(2).

Table 18[509]

	EF_W_COMP_WORKOVERS_FRAC Completions and Workovers with Hydraulic Fracturing	EF_W_COMP_WORKOVERS_NO_FRAC Completions and Workovers without Hydraulic Fracturing
Total Reported Methane Emissions (MT CH4)	**26,866**	**788**
Methane Emissions from Horizontal wells	25,445	-
Methane Emissions from Vertical wells	1,412	-
Methane Emissions: Gas Flared? Yes	6,503	3
Methane Emissions: Gas Flared? No	20,354	786
Methane Emissions: REC? Yes	23,537	-
Methane Emissions: REC? No	3,014	-
Methane Emissions: Reduced Emission Workover? Yes	56	-
Methane Emissions: Reduced Emission Workover? No	249	-
Number: REC? Yes	9,982	-
Number: REC? No	1,226	-
Number: Reduced Emission Workover? Yes	234	-
Number: Reduced Emission Workover? No	33	-
Percent of emissions with reported time before separator	16%	-
Methane Emissions Before Separator	2,371	
Methane Emissions After Separator	1,901	

A key difference between the New Mexico and Colorado rules is that New Mexico does not require flowback vessels to be "vapor tight" but rather requires them to deploy a control that

509 EDF analysis of GHGRP data.

operates as a closed vent system.[510] We believe this slight variation in the requirements is appropriate, as concerns have been raised that the vapor tight language raises safety concerns.[511]

We recommend EPA prohibit venting during the initial flowback stage of well completions, as New Mexico and Colorado have done, by requiring operators route flowback to a controlled, enclosed flowback vessel. Requiring emissions control during the initial flowback stage, as demonstrated by these state rules is technically feasible and would close a loophole that allows uncontrolled venting to the atmosphere.

2. Prohibiting venting during the initial flowback stage is cost-effective

Controlling emissions during the initial flowback stage is cost effective, as illustrated by analysis conducted by the Colorado Department of Public Health and the Environment ("CDPHE") when it adopted its requirements, as well as analysis conducted by EDF and reviewed by technical experts in support of the New Mexico requirements. To estimate the costs of its rule, Colorado assumed operators needed between ten to fifteen 500 bbl flowback vessels at a multi-well production facility. CDPHE assumed new storage vessels would cost $30,500 and used storage vessels would cost between $7,000 and $19,000. Colorado assumed a one-time capital cost of $500 for steel piping, a one-time cost of $500 to install the steel piping, and operation and maintenance costs of $500. The analysis assumed a 15-year lifespan for the necessary equipment. Colorado accordingly concluded that the annualized cost per flowback tank would be $4,830. Assuming an average of 12 flowback tanks, this equates to an annualized cost of $57,958 per well site.[512]

EDF's experts reviewed Colorado's estimate and found that it was reasonable and even likely conservative, as it represented a "'worst-case cost effectiveness estimate' because it assumed an operator would use the 12 flowback tanks only once, at one well site. More likely operators would use the same flowback tank at multiple wells for the lifetime of the tanks."[513]

Relying on the CDPHE cost-effectiveness analysis, EDF evaluated the policy prohibiting venting during the initial flowback stage in New Mexico.[514] The analysis found that controlling emissions during the initial flowback stage could be implemented at a cost of $53.79 per ton methane. EDF also estimated the cost-per-ton to reduce VOC emissions under this policy. Using the statewide average methane-to-VOC ratio for completions, EDF estimated the cost-

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[510] N.M. Code R. § 20.5.20.127.B.(2) (2023).

[511] N.M. Env't Improvement Bd., In the Matter of Proposed New Reg. 20.2.50 NMAC-Oil and Gas Sector-Ozone Precursor Pollutants No. EIB 21-27 (R), Notice of Intent to Present Rebuttal Technical Testimony on Behalf of Oxy USA Inc., Testimony of Danny Holderman, Ex. 2, pp. 3-4 (2021) (Attachment X).

[512] Colo. Dep't Pub. Health & Env't, Air Quality Control Commission, *Cost Benefit Analysis for Proposed Revisions to AQCC Regulation No. 7* at 27–28 (Sept. 4, 2020) (submitted as an attachment to Earthjustice et al., Doc. ID. No. EPA-HQ-OAR-2021-0668-0758, https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0668-0758)

[513] New Mexico Env. Improvement Board, In the Matter of Proposed New Reg. 20.2.50 NMAC-Oil and Gas Sector-Ozone Precursor Pollutants No. EIB 21-27 (R), Direct Testimony of Thomas Alexander, at 14 (2021) (Attachment Y).

[514] New Mexico Env't Improvement Board, In the Matter of Proposed New Reg. 20.2.50 NMAC-Oil and Gas Sector-Ozone Precursor Pollutants No. EIB 21-27 (R), Direct Testimony of Hillary Hull, at 15 (2021) (Attachment Z).

effectiveness to be $259.48 per ton VOC reduced. As such, requiring control of emissions during the initial flowback stage is overwhelmingly cost-effective.

3. We urge EPA to remove the technical infeasibility exception

Additionally, consistent with our comments in Section F for associated gas venting, we reiterate our recommendation from our 2021 comments (pp. 178-79) that EPA remove the technical infeasibility exception for the separation flowback stage. Combustion should only be allowed during an upset condition, as New Mexico has required.[515] This will help ensure that the technical infeasibility exception is not misused, and ensure operators are using equipment that is appropriately sized for the needs of the flowback scenario.[516]

Also consistent with our comments to EPA in Section F regarding associated gas venting, we recommend EPA define "Upset Condition" to mean "a sudden, unavoidable failure, breakdown, event, or malfunction beyond the reasonable control of the operator that substantially disrupts operations, but does not include a failure or breakdown that is caused entirely or in part by poor maintenance, careless operation, or other preventable equipment failure or breakdown." This definition draws from the definition of "Upset Condition" in Colorado[517] and the definition of malfunction in the New Mexico rules.[518]

H. Combustion Control Devices

In situations where flaring occurs, operators would be required to route associated gas through a closed vent system that meets the requirements proposed at section 60.5411b(a) and (c) to a control device that reduces emissions by at least 95% and meets the conditions of section 60.5412b(a)-(c).[519] We strongly support these requirements, which we believe are critical for addressing the commonly-observed problems from inefficient, malfunctioning, and unlit flares. Below, we explain why EPA's proposed control device requirements are necessary and suggest additional improvements.

The problem of unlit and malfunctioning flares is a well-documented and prevalent issue that is a significant source of methane emissions. EDF scientists have assessed flare performance in the Permian Basin with a series of helicopter-based infrared camera surveys.[520] Based on over 1,000 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

[515] N.M. Code R. § 19.15.27.8.C.(2)(b) (2023).
[516] 2022 Joint Environmental Comments, *supra* note 1, at 179–80.
[517] 2 Colo. Code Regs. § 404-1-100–21 (2023) (defining upset condition as "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").
[518] N.M. Code R. § 19.15.27.7.M (2023) (defining a malfunction as "sudden, unavoidable failure or breakdown of equipment beyond the reasonable control of the operator that substantially disrupts operations, but does not include a failure or breakdown that is caused entirely or in part by poor maintenance, careless operation, or other preventable equipment failure or breakdown.").
[519] Proposed 40 C.F.R. § 60.5377b.
[520] Permian MAP, *Flaring Aerial Survey Results (2021)*, https://www.permianmap.org/flaring-emissions/ (last visited Feb. 13, 2023).

partially combusting the methane and the rest is escaping to the atmosphere.[521] On-the-ground flare combustion efficiency is thus much worse than EPA has assumed and than what regulatory standards require.[522] 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.[523]

Other recent studies have confirmed that unlit or malfunctioning flares are one of the largest sources of methane emissions.[524] A study consisting of in situ measurements of lit flares found an average combustion efficiency of 91% for flares in the Permian Basin.[525] When accounting for unlit flares, the study that found average efficiencies of flares across major production basins range between 85% and 93%.[526] Multi-basin research has identified unlit flares across the entire country, and a Permian Basin study using flights conducted in 2020 found 5% of all active flares were unlit.[527]

Improved control device performance is feasible and already required by leading states. For example, Colorado requires operators to use an enclosed combustion device with a design destruction efficiency of at least 98% for hydrocarbons.[528] And New Mexico requires control devices used to abate well completion emissions either meet a 95% or 98% destruction efficiency. Specifically, if an operator uses an enclosed combustion device or thermal oxidizer, the destruction efficiency must be at least 98% for hydrocarbons.[529] If operators uses a different type of control device (e.g., a flare), it must have a control efficiency of at least 95% for hydrocarbons.[530]

We strongly support EPA's improved control device requirements, which we believe will help address the serious problems posed by unlit and malfunctioning flares. By using the pilot and flow monitoring devices in combination with one another, operators will be able to measure the amounts of combusted and vented gas during periods in which the flare is unlit. In 2021, only 20% of flare units across in the Permian basin across all industry segments had continuous flow monitoring according to the GHGRP.[531] The proposed requirements will improve the accuracy and reliability of the reported data, while enabling operators to timely address flare malfunctions. The addition of continuous monitoring requirements of the pilot light and gas flow rate are significant and low-cost improvements that will help ensure proper combustion and will also support EPA improving the reporting of unlit flare emissions.

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[521] *Id.*
[522] *Id.*
[523] *Id.*
[524] *See, e.g.*, Daniel H. Cusworth et al., *Intermittency of Large Methane Emitters in the Permian Basin*, 8 Env't Sci. Tech. Letters 567 (2021), https://pubs.acs.org/doi/abs/10.1021/acs.estlett.1c00173.
[525] Plant et al., *supra* note 174.
[526] *Id.* at Table 1.
[527] David R. 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/.
[528] 2 Colo. Code Regs. § 404-1-903, R. 903.d.(5) (2023).
[529] N.M. Code R. § 20.5.20.127.B.(1)(2) (2023).
[530] *Id.*
[531] U.S. Env't Protection Agency, *Greenhouse Gas Reporting Program Flare Unit Data*, https://www.epa.gov/ghgreporting/data-sets (last visited Feb. 13, 2023).

EPA has included two exemptions to the flow rate requirement. The first is available if an engineering assessment of the sources vented to the flare indicates that the maximum gas flow rates would not exceed the maximum flare tip velocity. The second is available if a backpressure preventer is installed which is set to operate at or above the minimum inlet gas flow rate. While ensuring gas flow rates are below the maximum flare tip velocity will help maintain efficient combustion, the engineering assessment and subsequent exemption from the flow monitoring requirement hampers EPA's ability to quantify and address emissions from unlit flares. Only when both the pilot light and gas flow of the flare stack are continuously monitored can operators accurately report the amount of gas emitted while a flare is unlit. Given the high rate of unlit flares in the Permian,[532] Eagle Ford, and Bakken formations,[533] flow monitoring of flares is necessary in all cases. We urge EPA to ensure that in *all* circumstances, both continuous monitoring of the pilot light and the flow rate occur, which are necessary to enabling an accurate and empirical assessment of flared gas emissions and an understanding whether flares are unlit. We believe there should be no exemptions from these two requirements given the high rate of observed unlit flares.

We also support the requirements for no visible emissions and monthly monitoring using Method 22. EPA could also consider alternative monitoring technologies and methods that would achieve equivalent or superior results. We believe this monitoring requirement, paired with the control device monitoring we recommend during LDAR surveys described in Section IV.B, will help ensure that unlit and malfunctioning flares are quickly detected and returned to compliant operating status. Method 22 monitoring can be conducted at the same time as LDAR surveys and therefore poses little-to-no additional burden on operators.

I. Storage Vessels

Storage vessels are a large source of the industry's methane emissions, accounting for nearly

400,000 tons annually according to the GHGI.[534] As we expressed in our comments last year, EPA has proposed several important and necessary changes to the requirements for storage vessels. We continue to support those changes for the same reasons articulated then, and we continue to urge EPA to lower the applicability threshold for storage vessels for the reasons stated in our prior comments.[535] We support EPA's new definition of "reconstruction" in the context of the storage vessel affected source. Finally, we also support EPA's proposal to require alarms on thief hatches.

1. EPA's new definition of reconstruction

We support EPA's proposed definition of "reconstruction" for storage vessels. EPA proposes that reconstruction of a storage vessel occurs when either (1) at least half of the storage vessels are replaced in the existing multi-vessel tank battery, or (2) when the replacement of new components exceeds 50 percent of the capital cost that would be required to construct a

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[532] Lyon et al., *Concurrent Variation, supra* note 527.
[533] Plant et al., *supra* note 174.
[534] *See* U.S. Env't Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990–2019* (April 14, 2021), https://www.epa.gov/sites/default/files/2021-04/documents/us-ghg-inventory-2021-main-text.pdf.
[535] *See* 2022 Joint Environmental Comments, *supra* note 1, at 140–45.

comparable entirely new facility. This definition closely mirrors the proposed reconstruction definition for pneumatic controllers, which Joint Environmental Commenters similarly support.[536] This proposal allows for reconstruction to occur regardless of any change in emissions rate, consistent with 40 C.F.R. § 60.15.

It is reasonable for EPA to equate replacing 50% of tanks at a site with replacements where "the fixed capital cost of components exceeds 50 percent of the fixed capital cost that would be required to construct a comparably entirely new facility." Because individual tanks are likely to have comparable replacement costs, it is reasonable to assume that there would be a one-to-one correlation between the percentage of tanks being replaced at a site and the percentage of the fixed capital cost that would be required to construct a comparable entirely new facility.

EPA has solicited feedback on what timeframe is appropriate for determining if a reconstruction has occurred. Joint commenters support mirroring the two-year rolling reconstruction time frame proposed for pneumatic controllers.[537] The two-year rolling period provides a reasonable method of determining whether an owner of an oil and natural gas site with storage tanks is actually pursuing an extensive tank replacement program, within the EPA's original intent in promulgating 40 C.F.R. § 60.1. The two-year timeframe also recognizes that it may be more cost-effective for operators to replace a larger portion of their tanks rather than initiate several, smaller replacement programs. Without a two-year window, operators could create multiple replacement programs below the 50% threshold over the course of several years to avoid compliance with OOOOb. Allowing this loophole would undermine Congress' intent that air quality be enhanced over the long term with the turnover of polluting equipment and with the intent of EPA's reconstruction provisions.

2. Proposed control measures for thief hatches

Joint Commenters support EPA's proposal to require that thief hatches be equipped with alarms, automated systems to monitor for pressure changes, or automatically closing thief hatches. Thief hatches act as pressure safety devices and, when operated properly, prevent emissions from escaping into the atmosphere. Thief hatches can open and unintentionally emit either through improper latching after routine operations (checking tank levels, etc.) or, as a result of a pressure build-up within the tank.[538] Open or malfunctioning thief hatches, if not closed or repaired promptly, can be responsible for large amounts of methane and VOC emissions as described in more detail above in the section addressing LDAR.[539] Because storage tanks are often located in

[536] *See* discussion of pneumatic controllers *infra* Section IV.D.
[537] *See* discussion of pneumatic controllers *infra* Section IV.D.
[538] Vance Ray, *Use wireless to monitor thief hatches*, Control (July 18, 2019), https://www.controlglobal.com/manage/asset-management/article/11301041/use-wireless-to-monitor-thief-hatches; Teledyne FLIR, *How Safe are Thief Hatches?* (June 18, 2021), https://www.flir.com/discover/instruments/gas-detection/how-safe-are-thief-hatches/.
[539] *See also*, Rutherford et al., *Closing the methane gap in US oil and gas and natural gas emissions inventories,* 12 Nature Comms. (Aug. 5, 2021), https://www.nature.com/articles/s41467-021-25017-4; Marc Mansfield et al., *Storage Tank Emissions Pilot Project (STEPP): Fugitive Organic Compound Emissions from Liquid Storage Tanks in the Uinta Basin* (July 17, 2017), https://documents.deq.utah.gov/air-quality/planning/technical-analysis/DAQ-2017-009061.pdf; Lesley Fleischman et al., Clean Air Task Force, *Tank Emissions from Controlled Tanks*, https://www.epa.gov/sites/default/files/2017-11/documents/5._catf_tank_presentation_for_inventory_workshop_final.pdf (last accessed Feb. 10, 2023).

remote locations with operating teams moving in and out, unsealed thief hatches could remain open for long stretches of time, freely emitting harmful methane and VOCs into the atmosphere.[540] This issue could be significantly improved by installing monitoring technology on this equipment.

Requiring operators to choose to install at least one type of mitigation technique is reasonable and cost-effective. Various developers of automation technology and equipment have made viable options for thief hatch monitoring available to industry operators.[541] When taking into account the lost revenue associated with wasted gas lost through open thief hatches, installing monitoring systems may ultimately benefit operators financially while also preventing harmful emissions.[542] Finalizing this proposal will be an important step for EPA in promulgating effective, economical standards for these sources.

J. Compressors

1. Reciprocating compressors

In our comments on the November 2021 proposal, Joint Environmental Commenters expressed support for 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 also urged EPA to lower the emissions threshold for rod packing replacement based on annual monitoring and to consider measures to reduce the significant emissions from compressor exhaust. We reaffirm those statements here.

a. EPA should lower the emissions threshold for rod packing replacement in reciprocating compressors.

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. In our response to EPA's November 2021 Proposal, Joint Environmental Commenters urged EPA to lower the emissions threshold for rod packing replacement. We reaffirm that position here. 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

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[540] *See* Jeff Jones, *Thief Hatch Monitoring for Storage Tank Emissions, Fugitive Emissions Journal* (June 2020), https://www.emerson.com/documents/automation/article-thief-hatch-monitoring-for-storage-tank-emissions-topworx-en-6867874.pdf.

[541] See, e.g., OleumTech, *Thief Hatch Monitoring: Simple and Cost-effective Solution for Minimizing Emissions Risk*, https://oleumtech.com/news-and-blogs/2021/02/thief-hatch-monitoring-solution-for-minimizing-emissions-risk (last visited Feb. 10, 2023); Scott Keller, *SignalFire Introduces Tilt Scout – the "Hatch Watchdog" Wireless Thief Hatch Sensor for Remote Thief Hatch Monitoring*, SignalFire, https://www.signal-fire.com/signalfire-introduces-hatch-watchdog-wireless-thief-hatch-sensor-remote-tank-monitoring/ (last visited Feb. 10, 2023).

[542] *See, e.g.*, Jeff Voorhis, *Best Practices for Vapor Recovery Systems to Reduce Venting and Flaring* at 4, https://www.epa.gov/sites/default/files/2016-04/documents/8voorhis.pdf (positing that when subtracting the estimated cost of wasted gas from estimated project costs, industry operators would ultimately experience a net gain.); Ray, *supra* note 538 (One company's costs for installing monitoring technology on an 8-tank battery totals $8,300).

all segments.[543] However, as explained in CATF's Reciprocating Compressor Cost Memo and Spreadsheet,[544] 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 such reductions.

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 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. Table 19 shows the cost summary for all segments; these abatement costs are very similar to costs for the current OOOOa requirement for new sources.[545] 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.[546]

Table 19

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	

b. EPA should not allow for repair instead of replacement of rod packing unless the emissions threshold is lowered to at least 0.5 scfm.

If EPA maintains the currently proposed emission threshold of 2 scfm, the agency must require replacement of rod packing (as opposed to also allowing for repair). Conversely, if EPA were to adopt an emissions threshold of 0.5 scfm, then repair of rod packing would offer emissions abatement that is comparable to that of replacing the rod packing. Table 20 shows the projected emissions reductions from rod packing replacement versus repair at both 2 scfm and 0.5 scfm. At

[543] Initial TSD, *supra* note 413, at 7-1 through 7-33.
[544] *See* Lesley Fleischman, *Reciprocating Compressor Cost Memo* (Jan. 24, 2022) (included as Attachment U to 2022 Joint Environmental Comments, *supra* note 1); Clean Air Task Force, *Reciprocating Compressor Cost Spreadsheet* (Jan. 24, 2022) (included as Attachment V to 2022 Joint Environmental Comments, *supra* note 1).
[545] Initial TSD, *supra* note 413, at Table 7-9 and 7-10.
[546] 86 Fed. Reg. at 63218.

a threshold of 2 scfm, merely repairing rod packing offers significantly less emissions reductions than would be possible with replacement.

Table 20

	3 year schedule	theshold 2 scfm replace	threshold 2 scfm repair to 2 scfm	theshold 1 scfm replace	threshold 1 scfm repair to 1 scfm	threshold .5 scfm replace	threshold .5 scfm repair to .5 scfm
Abatement %	77% (72-82%)	66% (57-72%)	43% (33-49%)	77% (73-80%)	66% (60-77%)	80% (77-84%)	76% (72-80%)
# of years between replacement	3	8 (6-14)	8 (6-14)	5 (4-6)	5 (4-6)	3 (3-4)	3 (3-4)

c. EPA should maintain the annual monitoring requirement from the November 2021 Proposal.

Joint Commenters do not support EPA's proposed change to allow monitoring of reciprocating compressors only every 8,760 operational hours as opposed to annually. An annual monitoring requirement is reasonable and does not impose an undue burden on operators. It is true that compressors may not be continuously operated all year at all facilities. However, the risk of malfunction from compressors that are only operated intermittently is high because nonuse can cause components to shift or corrode while unobserved. Compressors that operate for even 1,000 hours a year have an equally high, if not higher, risk of malfunction or deterioration as compared to compressors that operate continuously. Only requiring that such compressors be monitored just once every nine years is unreasonable. Such a monitoring schedule would likely allow for emissions well above the threshold to go unchecked.

d. EPA should develop standards for compressor exhaust.

Finally, EPA should develop standards to reduce emissions from compressor exhaust. These emissions are substantial: 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, the agency 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.[547]

2. Centrifugal compressors

Joint Commenters reaffirm our support for extending centrifugal compressor standards to existing sources and to centrifugal compressors at centralized production facilities. 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. Additionally, Joint Commenters support setting methane and VOC standards for dry deal centrifugal compressors.

K. 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.

1. Affected facility definition

In our comments on the November 2021 proposal, Joint Commenters supported Option 1 of EPA's proposed affected facility definition 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.

In the Supplemental Proposal, EPA has put forward an additional possible definition for liquids unloading affected facilities. Under this second option, "liquids unloading affected facility" is defined as "every well that undergoes liquids unloading using a method that is not designed to completely eliminate venting."[548] By contrast, under Option 1, a "liquids unloading affected facility" is defined simply as "every well that undergoes liquids unloading,"[549] meaning that wells utilizing a non-emitting method for liquids unloading would still be affected facilities and subject to certain reporting and recordkeeping requirements.

Joint Environmental Commenters continue to support Option 1 rather than Option 2. Defining these sources to cover *all* wells undergoing liquids unloading 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. 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)."[550] 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

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[547] Sierra Club et al., Comment Letter on New Source Performance Standards: Oil and Natural Gas Sector; Review and Proposed Rule for Subpart OOOO, at 48 (Nov. 30, 2011), https://www.regulations.gov/comment/EPA-HQ-OAR-2010-0505-4240.
[548] 87 Fed. Reg. at 74778.
[549] *Id.*
[550] 86 Fed. Reg. at 63179.

these errors and how they can be prevented. EPA should therefore finalize Option 1 and require operators of *all* wells undergoing liquids unloading 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 in which 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 "an owner or operator [must] establish and follow [best management practices] to minimize methane and VOC emissions during liquids unloading events to the extent possible."[551] 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."[552] 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.

2. "Modification" definition

In the Supplemental Proposal, EPA has proposed to revise the "modification" definition for a liquids unloading affected facility to apply to a single well that undergoes hydraulic fracturing or refracturing. Previously, EPA had proposed that a "modification" be defined as a well liquids unloading event. Joint Commenters urge EPA to reconsider this change, and we support the previously proposed definition that a well liquids unloading event constitutes a modification.

L. 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.

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."[553] 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

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[551] 86 Fed. Reg. at 63179.
[552] 86 Fed. Reg. at 63179.
[553] 86 Fed. Reg. at 63182.

for ensuring compliance that will also help operators detect any anomalous sources at the processing plant.

We also support the repair timeframe proposed in the November 2021 proposal, which 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. Joint Commenters urge EPA to require repair within 5 days of detection without exception for technical infeasibility.

EPA is not proposing to require replacement of leaking equipment with Low-E valves because the agency claims such a replacement is not appropriate for all valve repairs. Joint Commenters urge EPA to reconsider this determination. 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.[554] 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.[555]

VI. Methane Emissions Reduction Program Equivalence Determination

The new section 136(f)(6)(A) of the Clean Air Act provides an exemption from the Inflation Reduction Act's methane charge for a facility that "is subject to and in compliance with methane emissions requirements" under section 111, and requires that the Administrator make a determination that (i) "[m]ethane emissions standards and plans pursuant to subsections (b) and (d) of section 111 have been approved and are in effect in all States with respect to the applicable facilities," and (ii) "compliance with the requirements described in clause (i) will result in equivalent or greater emissions reductions as would be achieved by the proposed rule of the Administrator entitled 'Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review' (86 FR 63110 (November 15, 2021)) ["November 2021 proposal"], if such rule had been finalized and implemented."

EPA solicits comment on comparing the equivalency of final "[m]ethane emissions standards and plans pursuant to subsections (b) and (d) of section 111" promulgated as part of this rulemaking to its November 2021 proposal "if such rule had been finalized and implemented" under section 136(f)(6)(A)(ii). As an initial matter, EPA should develop an updated analysis of the emissions impacts of the November 2021 proposal as if it were finalized and implemented. Next, EPA should take a multi-faceted approach to evaluating equivalency, evaluating whether the emissions reductions achieved under the final implemented standards are equivalent or greater to the reductions that would have been achieved under the November 2021 proposal across multiple parameters—including emissions reductions equivalency across time periods, geographies, and sources. Finally, EPA should make the evaluation and equivalency determination once standards are fully in effect by comparing the November 2021 proposal to final section 111(b) regulations and final, approved state and tribal plans (and any Federal Plan if applicable).

[554] *See* Colorado Air Pollution Control Division, *Rebuttal Prehearing Statement, Proposed Revisions to Regulation Numbers 7 and 22* (Dec. 14–17, 2021).
[555] *Id.*

A. Estimating Emissions Reductions Under the November 2021 Proposal

As an initial matter, EPA should develop an updated analysis of the emissions reductions that would have been achieved by the November 2021 proposal, if finalized and implemented. While EPA estimated emissions reductions in a Regulatory Impact Analysis and Technical Support Document for that proposal, the agency updated its methodologies and assumptions for calculating emissions impacts in the supplemental proposal.[556] And as we explained in comments on the earlier proposal, EPA underestimated emissions reductions associated with the rule.[557] Thus, when EPA updates subpart W to ensure that reporting is based on empirical data pursuant to Clean Air Act section 136(h), it should also utilize that data to develop an updated analysis of the emissions reductions that would have been achieved under the November 2021 proposal.

B. Temporal Elements

To determine equivalency between final standards and plans and the November 2021 proposal across time, EPA should require that equivalent reductions be achieved both (1) in each year that the section 136(f)(6)(A) exemption may be in effect and (2) in the aggregate across a multi-year period through 2035, as analyzed in the November 2021 proposal.

First, the equivalency determination must apply in each year that any exemption from the waste charge is available. For example, if final standards and plans have been approved, are in effect, and have been fully implemented in all states in 2028, EPA should evaluate whether those standards and plans will achieve equivalent or greater reductions to what the November 2021 proposal would have achieved in 2028 if it had been fully implemented. Evaluating equivalency on a year-by-year basis is necessary to account for the fact that final section 111 standards and plans may take effect on different timelines than projected in the November 2021 proposal,

Second, equivalency must apply over the multi-year period through 2035 evaluated in the November 2021 proposal. EPA estimated in November 2021 that its proposed standards would deliver 41 million short tons of methane emissions reductions over 2023-2035.[558] Congress was aware of the estimated impact of the November 2021 proposal's presumptive standards and incorporated an expectation of equivalent effectiveness into section 136(f)(6)(A)(ii).[559] Final standards and plans should therefore be compared to this timeline and deliver equivalent or greater reductions in the multi-year period through 2035, in addition to equivalent or greater reductions in each year that they are fully in effect and implemented. This will help ensure that final standards and plans will achieve equivalency to the November 2021 proposal, even if those final standards and plans are implemented on a later timeline.

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[556] 87 Fed. Reg. at 74713.

[557] *See* 2022 Joint Environmental Comments, *supra* note 1, at 60, 85–86.

[558] 86 Fed. Reg. at 63122, Table 4.

[559] *See* Greg Dotson and Dustin Maghamfar, *The Clean Air Act Amendments of 2022: Clean Air, Climate Change, and the Inflation Reduction Act*, 53 Env't L. Reporter 10017, 10032 (Jan. 2023), https://www.eli.org/sites/default/files/files-pdf/53.10017.pdf.

C. Geographical Elements

Geographically, EPA should conduct a state-by-state analysis across all states nationwide to determine equivalency. As part of this analysis, EPA must first evaluate the standards and plan in effect in each state to ensure that reductions equivalent those under the November 2021 proposal are being achieved. As discussed below, it is critical that EPA evaluate the section 111(b) standards and section 111(d) plan that are actually in effect in each state. Evaluating the standards and plans in every state aligns with section 136(f)(6)(A)(i)'s directive to evaluate "standards and *plans* . . . in effect in all States" (emphasis added) for equivalency under section 136(f)(6)(A)(ii).

Furthermore, EPA should compare emissions reductions expected under each state's final section 111(d) plan to the emissions reductions that would have been achieved under the November 2021 emissions guidelines if finalized in that state. This follows from section 136(f)(6)(A)(ii)'s directive that the comparison is to the proposed November 2021 emissions guidelines "if *such rule* had been finalized and implemented" (emphasis added), which contemplates a full implementation of the November 2021 proposed standards and emissions guidelines in each state. EPA's obligation to evaluate *final* state plans is discussed further below. If a state's final section 111(d) plan achieves fewer reductions than the November 2021 proposal's emission guidelines, including due to variances granted pursuant to RULOF considerations, then EPA could not make the equivalency determination.

Evaluating equivalency with regard to each state incentivizes the greatest reductions in emissions under both the waste charge program and section 111, whereas solely considering aggregated nationwide emissions (which could allow for lower emissions reductions in one state to be offset by higher emissions reductions in another state) does not. Evaluating whether stronger standards in one state offset less stringent standards in another state would also be technically difficult, given that many section 111 standards are non-numerical design, equipment, work practice, and/or operational standards that do not quantify emissions.[560] However, while a nationwide analysis in and of itself is insufficient in the absence of a parallel state-by-state analysis, EPA must still ensure that aggregated nationwide emissions reductions are equivalent or greater than those under the November 2021 proposal. By ensuring that each state is achieving equivalent reductions under the section 111(b) standards and its section 111(d) plan, a nationwide determination of equivalency across all states should necessarily follow.

D. Timing of Equivalency Determination

EPA should make the evaluation and equivalency determination once standards of performance pursuant to CAA sections 111(b) and 111(d) are fully promulgated nationwide by comparing the November 2021 proposal to final section 111(b) regulations and final, approved state plans (and any Federal Plan if applicable). The plain language of section 136 indicates that EPA must evaluate final standards and plans for equivalency. Section 136(f)(6)(A)(i) requires "methane emissions standards and plans pursuant to subsections (b) and (d) of section 111 [to] have been approved and . . . in effect in all States." In turn, section 136(f)(6)(A)(ii) requires EPA to

[560] EPA discussed similar challenges in the supplemental proposal in the context of declining to conduct a total program evaluation for purposes of determining equivalency of a state plan with the OOOOc presumptive standards. *See* 87 Fed. Reg. at 74813.

determine that “compliance with the requirements described in clause (i)” will achieve equivalent reductions to the November 2021 proposed rule. The “requirements” evaluated for equivalency in section (ii) are referring to “emissions standards and plans” that “have been approved” and are “in effect in all States.”

Furthermore, because section 136(f)(6)(A)(ii) directs EPA to determine that “compliance” with emissions standards and plans will achieve equivalent reductions to the November 2021 proposal, EPA must consider how facilities will comply with final standards and plans. This necessarily entails an evaluation of whether fully implemented state plans—including any less stringent standards adopted based on an invocation of RULOF—achieve equivalent reductions to the November 2021 proposal. And because that proposal did not indicate if or how variances might have been approved, and instead only contained presumptive standards in the proposed emissions guidelines, EPA cannot hypothesize states’ invocation of RULOF under the November 2021 proposal, but must instead assume each state fully implemented the proposed November 2021 emissions guidelines when estimating reductions. This is consistent with EPA’s emissions reductions estimates in the regulatory analysis for the November 2021 proposal, where the agency did not assume any variances and instead assumed that state plans would fully reflect the emission reductions projected under the proposed guidelines.

Lastly, evaluating final, approved state plans for equivalency will both incentivize expeditious submission of state plans and disincentivize overbroad invocation of RULOF to justify less stringent standards in state plans.

VI. Conclusion

Joint Environmental Commenters again appreciate the opportunity to submit these comments on EPA’s supplemental proposal to reduce methane and other air pollutants from the oil and natural gas sector.

Sincerely,

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