ENVIRONMENTAL DEFENSE FUND
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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

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Revisions and Confidentiality	)	**<u>Docket No. EPA-HQ-OAR-2019-0424</u>**
Determinations for Data Elements Under	)	
the Greenhouse Gas Reporting Rule	)	*Via regulations.gov*
	)	*October 6, 2022*[1]
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Environmental Defense Fund (EDF) respectfully submits the following comments on EPA's proposed *Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rul*e, 87 Fed. Reg. 36,920 (June 21, 2022). EDF is one of the world's leading environmental organizations, with the mission to build a vital earth for everyone. Our key priorities are to stabilize the climate and strengthen people's ability to thrive in a changing climate. We do this by using science, economics, law, and uncommon partnerships to find practical and lasting solutions to the most serious environmental problems. We can avoid the most catastrophic consequences of global warming by limiting the world's temperature rise to 1.5°C (2.7°F). Doing so requires dramatically cutting greenhouse gas emissions. EPA's Greenhouse Gas Reporting Program (GHGRP) is a fundamental underpinning of U.S. climate policy – understanding the sources of emissions is critical for informing approaches to mitigation. Ensuring the accuracy of information reported through the GHGRP is necessary for developing policies that achieve the Biden Administration's commitment to reducing domestic greenhouse gas emissions by 50-52% from 2005 levels by 2030. EDF strongly supports updates to the GHGRP, and we urge EPA to strengthen key provisions.

[1] Attachments submitted to Regulations.gov.

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INTRODUCTION

The GHGRP plays a crucial role in the development of U.S. climate policy; it helps policymakers, stakeholders, and the public better understand domestic greenhouse gas emissions and how those emissions contribute to climate change. Data collected through the GHGRP, including the sources, magnitude, and distribution of greenhouse gas emissions across the country, inform decisions about how to address those emissions through legislation, regulation, and voluntary efforts. Emissions reported to the GHGRP cumulatively represent one of the largest drivers of global climate change. Understanding greenhouse gas pollution through high-quality, representative, and granular data is critical for developing effective policy solutions to abate this pollution. And reducing domestic greenhouse gas pollution is an urgent priority–we must cut emissions in half from 2005 levels by 2030 to avoid the most catastrophic effects of climate change.

Our comments on EPA's proposal suggest improvements across a variety of subparts with the overarching goal of ensuring reported data accurately reflects real-world emissions. For some subparts where the latest science shows discrepancies between reported data and observed emissions, we suggest changes that are more significant. For example, we recommend that EPA propose further revisions to subpart W to ensure reporting is accurate and based on empirical data in compliance with the recent congressional directive in the Inflation Reduction Act. Even for subparts where we suggest broad changes, those suggestions are followed with more narrow recommendations for improvements to EPA's proposed updates. We appreciate EPA's work to update the GHGRP, and we hope that our comments are informative and useful in this effort.

EXECUTIVE SUMMARY

Below is a summary of our topline recommendations for each subpart which are explained in more detail in the subsequent sections of this comment.

Subpart C - General Stationary Fuel Combustion Sources: We support reporting on the unit type, maximum rated heat input, and an estimate of the share of total annual heat input for each unit, and we recommend it be extended to reporting on common stack configurations and the alternative part 75 configuration. We also recommend that EPA gather data on installation year of individual combustion units and the typical operating-temperature range and output type of each unit.

Subpart P - Hydrogen Production: EDF recommends that EPA consider the problem of hydrogen emissions and the associated climate implications, especially as the hydrogen supply chain grows. We urge EPA to expand the hydrogen production source category to include electrolysis facilities, and require reporting on those facilities' energy consumption.

Subpart Q - Iron and Steel Production: EDF supports EPA's proposal to require that facilities report the type of unit and the annual production capacity of each unit, but we suggest that EPA ask facilities to report actual production levels (not capacity). We also support EPA's proposal to allow facilities to determine the carbon content of process inputs and outputs using analyses provided by material recyclers. However, carbon content can vary widely, as can production processes for different products, both of which may affect emissions. Therefore, it should be the facility's responsibility to make these determinations as accurately as possible and relying on supplier and recycler estimates should be a last resort.

Subpart W - Petroleum and Natural Gas Systems: EDF recommends that EPA propose additional updates to implement the recent congressional directive to ensure that subpart W reporting is based on empirical data and accurately reflects total emissions. Our comments set forth recommendations for how EPA can undertake this, which include site-level measurements, top-down estimates, and a reconciliation process. We believe EPA can begin taking steps toward those comprehensive revisions by adopting our recommendations on the updates EPA has already proposed. We therefore also include comments based on the scope of EPA's proposal which cover: ownership transfers, large release events, pneumatic emission factors, leaker emission factors, flare reporting, compressors, storage tanks, gathering lines, liquids unloading, and LNG/processing.

Subparts X & Y - Petrochemical Production and Petroleum Refineries: EDF supports several of EPA's proposed revisions to subparts X and Y but urges EPA to adopt a more inclusive approach to flare calculation and reporting to ensure more accurate emission estimates from petrochemical production. EDF also specifically requests that EPA reconsider the exclusion of SSM events less than 500,000 scf/day from the reporting requirements to avoid the risk of loopholes and underreporting of harmful emissions.

Subpart HH - Municipal Solid Waste Landfills: We recommend that EPA make a number of changes to bring reported emissions into better alignment with observed emissions. These include: adjusting the collection efficiency assumptions to better align with specific landfill management practices; adjusting the oxidation assumptions to better account for site-specific and climatic factors; removing the option to calculate and report emissions based on "back-calculation" from the quantity of methane collected; collecting site-level waste characterization data to improve the accuracy of methane generation estimates; improving flared emission reporting and lowering the default destruction efficiency factors; and requiring advanced methane detection technologies in the reporting process as a critical check on the bottom-up equations.

Subpart PP - Suppliers of Carbon Dioxide: EDF supports the inclusion of direct air capture (DAC) as a CO2 capture source under subpart PP but recommends that EPA strengthen the relevant life cycle analysis (LCA) reporting requirements, including through adopting ISO 14040/14044 for DAC LCA, requiring suppliers to define a cradle-to-gate boundary for their system, and requiring suppliers to report and account for the full emissions impact of their system.

Subpart RR - Geologic Sequestration of Carbon Dioxide: EDF recommends that EPA make clear that subpart RR applies to both onshore and offshore carbon dioxide injection facilities.

Subpart VV - Geologic Sequestration of Carbon Dioxide with Enhanced Oil Recovery Using ISO 27916: EDF recommends that EPA clarify that facilities subject to subpart VV – those demonstrating secure storage utilizing ISO 27916 – must use subpart VV for GHGRP reporting instead of subpart UU. Current language leaves ambiguity on this issue, which we believe is in error and in conflict with EPA's stated intent for adoption of the new subpart VV.

Energy Consumption: EDF recommends that EPA require reporting of data on energy consumption by facilities that are already subject to reporting requirements under the GHGRP, as well as by facilities that meet certain thresholds for overall energy consumption and/or energy-use capacity (depending on the type of facility). In collecting this data, the agency should distinguish between purchases of electricity and other forms of energy. Regarding electricity purchases, we recommend that EPA require reporting of a wider range of attributes.

RECOMMENDATIONS BY SUBPART

I. Subpart C - General Stationary Fuel Combustion Sources[2]

We support EPA's proposal to require general stationary fuel combustion sources to report the unit type, maximum rated heat input, and an estimate of the share of total annual heat input for each unit, including those in either an aggregation of units or common pipe configurations.[3] These requirements also should be extended to owners and operators reporting emissions for common stack configurations under 40 C.F.R. § 98.36(c)(2) or the alternative part 75 configuration under 40 C.F.R. § 98.36(d), for the reasons discussed below. In addition, we recommend that EPA require data on the installation year of individual combustion units and, for boilers, the typical operating-temperature range and output type (i.e., water, steam, or other).

A. EPA Should Extend Proposed Unit-Level Reporting Requirements for Common Stack Alternative Part 75 Configurations

EPA proposes to modify GHGRP reporting to "require reporting for each unit in either an aggregation of units or common pipe configuration, excluding units less than 10 mmBtu/hr from both, of the unit type, maximum rated heat input capacity, and an estimate of the fraction of the total annual heat input."[4] EPA already requires owners and operators using the individual unit configuration to report unit type and maximum rated heat input.[5] "The individual unit information allows the EPA to aggregate emissions according to unit type and size and provides a better understanding of the emissions from specific unit types."[6] Conversely, the lack of this unit-specific information in other configurations represents "a significant gap in the EPA's ability to aggregate subpart C emissions data by unit type and size."[7]
We agree that unit-specific data is key to understanding not only the distribution of emissions across unit types and sizes, but also the greenhouse gas abatement potential through various decarbonization strategies. Certain emissions controls may prove more cost-effective for large sources. Furthermore, certain abatement strategies may be better suited for certain unit types and uses, but this important data is currently obscured. Unit-specific information on unit type, size, and share of heat input could assist EPA in developing new source performance standards (NSPS) and emission guidelines for existing sources under Clean Air Act section 111. Developing NSPS and emission guidelines are among the purposes expressly mentioned in Clean Air Act section 114, which broadly authorizes EPA to adopt reporting requirements that would facilitate the agency's implementation of the Act.[8]

The data EPA has proposed to collect is essential and would fill a large gap in the identification and characterization of the sources of various industrial subsectors' emissions. For instance, using 2014 data

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[2] Our comments on subpart C were developed through joint collaboration with the Clean Air Task Force and contain similar recommendations.
[3] 87 Fed. Reg. at 36,939.
[4] *Id.*
[5] *See* 40 C.F.R. § 98.36(b)(2), (3).
[6] 87 Fed. Reg. at 36,939.
[7] *Id.*
[8] 42 U.S.C. § 7414(a)(1).

from the GHGRP,[9] approximately 58% (65 $MMTCO_2$) of emissions reported in the Chemical Manufacturing subsector (NAICS code 325) are listed as "other combustion source" (OCS), a designation used when facilities are reporting aggregation of units or common pipe configurations. Other industrial subsectors have similarly large percentages of emissions from uncharacterized combustion sources:

Subsector	Total CO_2 Emissions in 2014 (MMT)	% of CO_2 Emissions from OCS Units
Petroleum and Coal Products Manufacturing	127	64%
Chemical Manufacturing	112	58%
Oil and Gas Extraction	62	77%
Primary Metal Manufacturing	66	53%
Food Manufacturing	35	58%
Glass Manufacturing	5	49%
Lime Manufacturing	10	48%

Obscuring the types, sizes, and heat inputs of the individual sources responsible for such a large share of this category's emissions renders EPA's task in regulating them difficult.

Among the sources reporting under subpart C, combined configurations account for a large proportion of emissions. EPA observes that the "Aggregation of Units" and "Common Pipe" configurations together account for 50% of emissions, which is more than the 45% accounted for by individual units.[10] Adding the "Common Stack" and "Alternative Part 75" configurations would cover the remaining 4% of emissions under this subpart, ensuring that all emissions under this subpart are covered.[11] Although they do not account for a large share of emissions, it would be reasonable to require owners and operators of sources in the latter two configurations—which together comprise just over 200 configurations—to report the same data. This approach would impose consistent requirements on all stationary combustion sources, providing EPA and stakeholders with a complete picture of the greenhouse gas abatement potential of various source categories. And, as noted above, none of the requested information on unit type, size, or annual heat input should be difficult to obtain and report. We therefore urge EPA to adopt the same requirements for the common stack and part 75 configurations.[12]

[9] Colin McMillan, *Nat'l Renewable Energy Lab., Industrial Facility Combustion Energy Use* (2016), https://data.nrel.gov/submissions/50.
[10] 87 Fed. Reg. at 36,939.
[11] *See id.*
[12] *See id.* (seeking comment on this topic).

B. <u>EPA Should Lower the Capacity Threshold for Reporting Individual Stationary Combustion Unit Characteristics</u>

The extension of unit-level reporting requirements recommended in these comments is reasonable, based on its content and scope. As EPA notes, owners and operators must already report the maximum rated heat input for an aggregation of units, which would involve summing the maximum rated heat input of individual units.[13] The share of total annual heat input should be available in company records.[14] And none of the requirements to report individual unit characteristics would sweep in facilities that are not already subject to the GHGRP, based primarily on the facility's subcategory and emissions.[15] This requirement will add little burden to reporters while providing EPA and stakeholders with important information.

EPA should consider lowering the size threshold for reporting unit characteristics below the 10 MMBtu/hr that EPA has proposed to retain.[16] A lower threshold would be reasonable because the full set of data on individual stationary combustion sources is crucial to assessing abatement potential from various industrial subsectors. Numerous stationary combustion sources including boilers deployed across a wide range of industrial subsectors are smaller than 10 MMBtu/hr.[17] In the case of industrial boilers, although these smaller boilers do not account for a large share of total capacity,[18] they often present the most viable opportunities for greenhouse gas emissions abatement including through electrification with heat pump technology.[19] Similarly, combustion units at natural gas compressor stations and storage facilities frequently do not meet a reporting threshold of 10 MMBtu/hr, meaning information on these units' characteristics is unavailable.[20] In 2016, EPA ultimately declined a recommendation to lower the threshold to 2.5 MMBtu/hr, noting that "lowering the proposed threshold to 2.5 MMBtu/hr, as opposed to 10 MMBtu/hr, would increase burden without significantly increasing the EPA's ability to verify emissions data."[21] The present objective, however, is not to check emissions data against aggregate capacity, which can be accomplished even while disregarding emissions from smaller sources.[22] Rather, it is to evaluate emission abatement opportunities across the universe of combustion sources, and omitting smaller sources may leave out some of the more cost-effective solutions. The low burden of additional reporting requirements and the paramount goal of reducing greenhouse gas emissions from combustion sources mean EPA should lower or eliminate the threshold to report unit characteristics.

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[13] 87 Fed. Reg. at 36,939-40.
[14] *See id.* at 36,940.
[15] *See* 40 C.F.R. § 98.2(a).
[16] 87 Fed. Reg. at 36,939.
[17] *See* Carrie Shoeneberger et al., *Electrification potential of U.S. industrial boilers and assessment of the GHG emissions impact*, 5 Adv. in Applied Energy 100089, at 5, Fig 3 (2022). More than 20,000 industrial boilers—approximately 53% of the boilers examined in this study—were smaller than 10 MMBtu/hr.
[18] *See id.*
[19] *See* Edward Rightor, Andrew Whitlock & R. Neal Elliott, Am. Council for an Energy Efficient Econ., *Beneficial Electrification in Industry*, at 15 (July 2020), https://www.aceee.org/sites/default/files/pdfs/ie2002.pdf.
[20] *See* AGA Comments on Proposed Rule: 2015 Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule, 81 Fed. Reg. 2536 (January 15, 2016), EPA-HQ-OAR-2015-0526-0071, at 2-3.
[21] 81 Fed. Reg. at 89,188, 89,204 (Dec. 9, 2016).
[22] *See id.* at 89,203.

C. EPA Should Collect Additional Data on Combustion Unit Vintage and Output Temperature

We also recommend that the agency require owners and operators of stationary combustion sources to report the year of each unit's installation. This information should be readily available and easily reported. In addition, the age of existing units could shape EPA's analysis of the effects of its NSPS, depending on the projected timing of replacement of existing sources, as well its emission guidelines, which may apply differently to sources with shorter remaining useful lives.[23] Units' vintages, when correlated to emissions rates, may also reveal any degradation in emissions performance over time. It will also provide states and other stakeholders with vital information to consider the age of these units and potential turnover time to inform climate policymaking. Because this information could be relevant in regulating a source category under section 111, and because it is reasonable to require it, it is within EPA's authority to seek it under section 114.

We recommend that EPA require reporting of the typical operating-temperature range and output type of the combustion unit (i.e., water, steam, or other). This information could prove critical in selecting the appropriate system of emission reduction for a single or several categories of combustion sources under section 111. For example, electric heat pumps present a viable alternative to boilers supplying heat below 150°C, which together account for more than 60% of the heat provided by boilers.[24] About 30% of process heat falls below the 150°C threshold, while process heat needed to reach higher temperatures can be supplied by solar thermal and nuclear generation.[25] Unit output type and typical operating-temperature range would not be difficult to obtain and report. Because this information is highly relevant to fulfilling statutory purposes and is straightforward to obtain and report, it would be both reasonable and important for EPA to require it under section 114.[26]

D. EPA Should Collect Data to Ascertain Flue Gas Stream CO_2 Concentrations

In a future rulemaking, EPA should consider expanding the requirements of subpart C to include reporting of data that would be needed to calculate the CO_2 concentration of each flue gas stream leaving one or more stationary combustion units. Units or groups of units using CEMS already measure hourly CO_2 concentrations,[27] so the additional requirement for these units would simply mean reporting that data to EPA. For individual units or groups of units sharing a stack without CEMS, the added requirements could involve data on fuel types and quantities of fuel combusted, as well as operating conditions (*e.g.*, the temperature, pressure, and volume rate of flow of the exiting gas), over a meaningful timeframe such as an hour or a day. Alternatively, the agency could require operators to calculate CO_2 concentrations themselves and report the results. However operators choose to comply, information on CO_2 concentrations in flue gas streams will be key to evaluating decarbonization strategies for stationary combustion units and other types of sources across many industrial subsectors. It would therefore be reasonable for EPA to require reporting

[23] *See* 42 U.S.C. § 7411(d)(1).

[24] *See* Peter Alstone *et al.*, Schatz Energy Research Center, Toward Carbon-Free Hot Water and Industrial Heat with Efficient and Flexible Heat Pumps, at 58-59 & Fig. 24 (Aug. 2021), http://schatzcenter.org/pubs/2021-heatpumps-R1.pdf.

[25] *See* U.S. Dep't of Energy, Industrial Decarbonization Roadmap, at 15-16 (Sept. 2022), https://www.energy.gov/sites/default/files/2022-09/Industrial%20Decarbonization%20Roadmap.pdf.

[26] As with any other information required under the GHGRP, EPA could determine whether the temperature of boiler output and the boiler output type qualify as confidential business information.

[27] 40 C.F.R. § 98.33(a)(4)(ii); *id.* at § 98.36(c)(2).

of this data—both for combustion emissions from the sources in subpart C, and potentially for process emissions from other GHGRP source categories as well.

II. Subpart P - Hydrogen Production

A. The Emerging Problem of Fugitive Hydrogen Emissions

Low- and zero-carbon hydrogen has the potential to help decarbonize certain sectors where electrification may not be feasible. Billions of dollars in federal funding for hydrogen research and development, along with a concerted push from industry, has accelerated the discussion and decisions being made around the future of hydrogen. Hydrogen could play an important role in the clean energy transition if its development is undertaken carefully in accordance with climate targets. But if done wrong, it could be worse for the climate in the near-term than the fossil fuels it would replace.[28] Hydrogen infrastructure is largely undeveloped; this presents an important opportunity for federal agencies to proactively create a clear and effective regulatory structure, avoiding reactive regulation like that which has characterized natural gas infrastructure buildout.[29] Hydrogen policy and investment strategies should be commensurate with 1.5° C pathways, evaluated based on their comprehensive effectiveness in delivering on climate, public health, environmental, and equity goals, and adapted through a continuous learning process as more research becomes available.

Today, less than 1% of hydrogen is made from renewable energy; the rest is made using fossil fuels, usually through a high-polluting process.[30] Hydrogen production globally is responsible for more greenhouse gas emissions than all of Germany.[31] Many stakeholders are focused on the climate impacts of hydrogen production methods (i.e., from natural gas resulting in "grey" hydrogen or "blue" if paired with carbon capture, or from renewable electricity resulting in "green" hydrogen). Stakeholders have also raised concerns about end-use combustion, which does not release greenhouse gases but can emit significant

[28] Ocko & Hamburg, *Climate Consequences of Hydrogen Leakage*, 22 Atmos. Chem. Phys., 9349–9368 (2022), https://acp.copernicus.org/articles/22/9349/2022/ [hereinafter "Ocko & Hamburg"].

[29] For example, regulations that guide infrastructure siting, design, construction, and operation to minimize or eliminate leakage may lessen the need for subsequent measures like leak detection and repair. Having clear and effective regulations in place can also send important signals to the industry about how infrastructure buildout should occur. *See* Drake D. Hernandez & Emre Gençer, *Laying the regulatory groundwork for hydrogen in the United States*, Utility Dive (June 8, 2021), https://www.utilitydive.com/news/laying-the-regulatory-groundwork-for-hydrogen-in-the-united-states/601408/ ("Rather than wait for this infrastructure to develop organically, the federal government should consider taking steps in advance to minimize regulatory risk for hydrogen infrastructure projects by providing clear regulatory treatment of said infrastructure.").

[30] Saadat & Gersen, *Reclaiming Hydrogen for a Renewable Future: Distinguishing Fossil Fuel Industry Spin from Zero-Emission Solutions*, Earthjustice (2021), https://earthjustice.org/features/green-hydrogen-renewable-zero-emission. In the U.S. today, nearly all hydrogen (95%) is produced from fossil fuels through an energy intensive industrial process called steam methane reformation (SMR), and roughly 60% of domestic hydrogen demand comes from crude oil refineries, where it is used to lower the sulfur content of diesel. *Id.* at 10.

[31] *Id.* (0.83 gigatons of CO2 in 2018).

amounts of health-harming pollution.[32] In addition, hydrogen leakage along the supply chain may also undermine potential benefits because hydrogen itself is a potent indirect greenhouse gas.[33]

When hydrogen is released directly into the atmosphere, it contributes to warming by "affecting chemical reactions that increase the amount of greenhouse gases including methane, tropospheric ozone, and stratospheric water vapor."[34] Hydrogen molecules are small and slippery, so the risk of leakage from various sources across production, transmission, storage, and end use is significant.[35] Hydrogen is also vented or purged into the atmosphere during some processes. When evaluating infrastructure buildout and use cases, it is necessary to ensure mechanisms are in place to estimate, detect, and quantify emissions in order to evaluate and minimize unintended climate consequences. Hydrogen applications that require greater transport and infrastructure connectivity increase the potential for leaks, whereas localized applications at or near the production source could potentially minimize leakage risks.[36]

[32] Combustion of hydrogen for energy in end-use sectors does not emit greenhouse gases, but it does produce significant NOx emissions that are potentially worse than comparable natural gas combustion. Thus, there may be a tradeoff between health-harming pollution and climate pollution that must be considered when exploring hydrogen applications. Alastair C. Lewis, *Optimising Air Quality Co-benefits in a Hydrogen Economy: A Case for Hydrogen Specific Standards for NOx Emissions*, 1 Env. Sci. Atmospheres 201 (2021), https://pubs.rsc.org/en/content/articlelanding/2021/ea/d1ea00037c.

[33] Ocko & Hamburg, *supra* note 28 at 9349–9368; Mejia et al, *Hydrogen Leaks at the Same Rate as Natural Gas in Typical Low-pressure Gas Infrastructure*, 45 Intl. J. Hydrogen Energy 8810 (2020), https://www.sciencedirect.com/science/article/abs/pii/S0360319919347275.

[34] Ocko & Hamburg, *supra* note 28.

[35] *Id.*

[36] Frazer-Nash Consultancy, *Fugitive Hydrogen Emissions in a Future Hydrogen Economy* at 6 (March 2022), https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1067137/fugitive-hydrogen-emissions-future-hydrogen-economy.pdf.

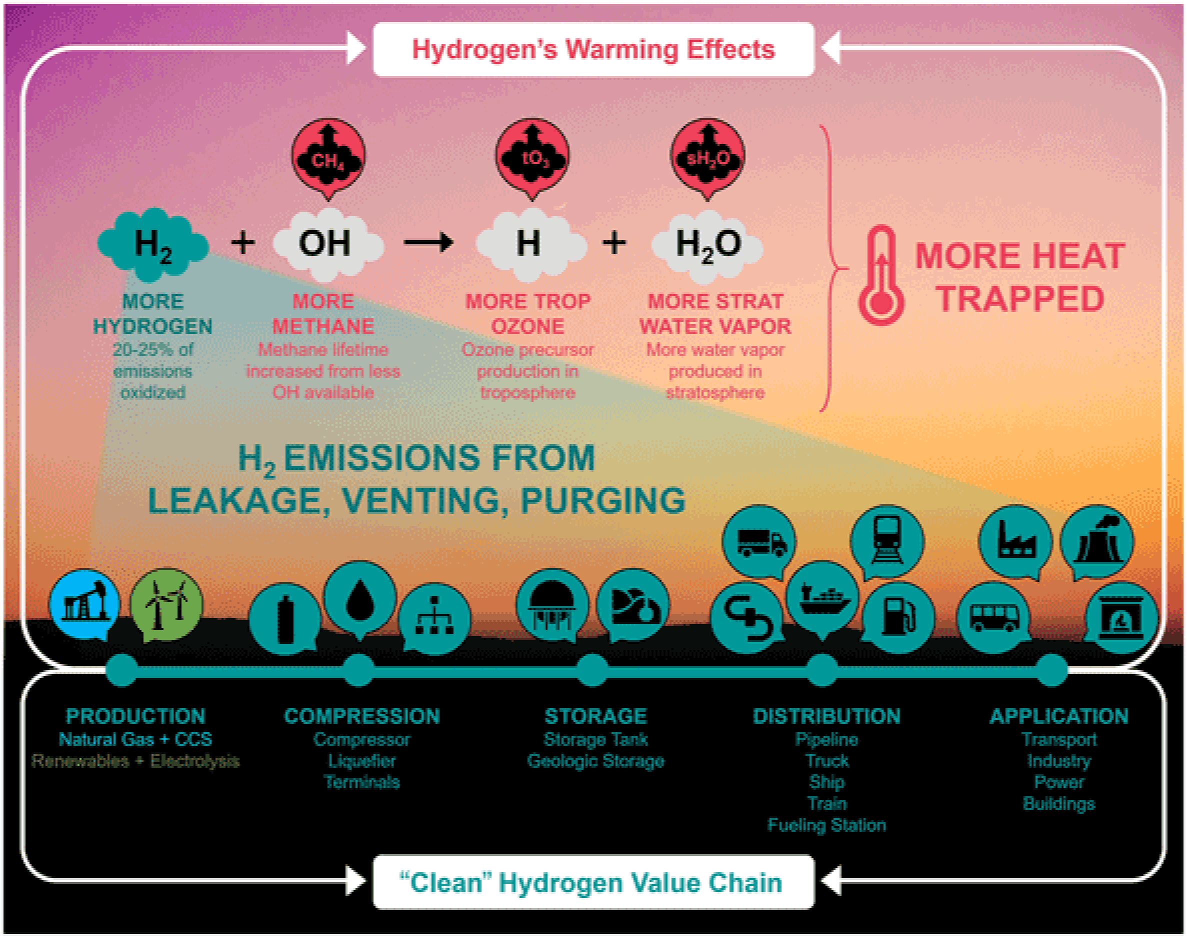

Figure 1: Hydrogen emissions throughout the value chain cause warming by increasing the persistence of methane, contributing to ozone formation, and producing stratospheric water vapor.

Recent peer-reviewed research analyzes the climate implications of hydrogen under a range of possible emission scenarios.[37] In best-case scenarios assuming a 1% emission rate across the value chain, the researchers find that "blue" hydrogen made from natural gas (with the carbon dioxide completely captured and 1% methane emission from the gas supply chain) could cut warming effects compared to traditional fossil fuels by roughly 70% percent over 20 years.[38] "Green" hydrogen produced using renewable electricity does even better, cutting the climate impact by over 95%.[39] But at a 10% hydrogen emission rate – which many scientists say is plausible – blue hydrogen (with 100% carbon capture and 3% methane emission) could actually increase the 20-year warming impact by 25%.[40] Green hydrogen with higher emissions would still reduce the 20-year warming effects by two-thirds relative to fossil fuels, but far less than the climate-neutral promise that many hydrogen champions claim.[41] Understanding hydrogen emissions and

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[37] Ocko & Hamburg, *supra* note 28.
[38] *Id.*
[39] *Id.*
[40] *Id.*
[41] *Id.*

leakage rates is therefore critical for determining the lifecycle greenhouse gas implications and potential benefits.

In addition to the climate implications, hydrogen leakage poses safety concerns. This is the case primarily in indoor settings and enclosed spaces, where a hydrogen leak can pose a fire hazard when mixed with air at a wide range of concentrations, and an asphyxiation hazard when it displaces oxygen in the air. Because its molecules are very small, hydrogen can sometimes be more prone than methane to leaking through joints, cracks, and seals in infrastructure. It can also permeate through materials used for natural gas distribution faster than methane, leading to deterioration and embrittlement of pipelines and other infrastructure, such as compressors.[42] This means that existing natural gas infrastructure is generally not suitable to transport hydrogen, and even the proposition of blending with natural gas in a mixture that contains a low percentage of hydrogen raises safety and environmental concerns.[43] Preventing leaks from hydrogen infrastructure is thus also important from a safety perspective.

EPA has important roles to play as the hydrogen economy develops, including through furthering our understanding of leakage and its climate impacts. In order to understand this problem and avoid a situation where climate-damaging, leaking infrastructure is built (or converted from gas infrastructure), EPA should develop methods for estimating, detecting, quantifying, and reporting hydrogen emissions from leakage, venting, and purging. Developing these methods is important even in the absence of mandated reporting–it can aid in industry- and government-led lifecycle accounting efforts, offering greater flexibility and degrees of comprehensiveness. It is also important for implementing EPA's authority under section 103 of the Clean Air Act.[44] As detection technologies progress alongside our understanding of hydrogen's climate impacts, EPA should evaluate including hydrogen as a greenhouse gas subject to reporting. EPA should work with DOE and other relevant agencies to develop best practices and guidelines for hydrogen infrastructure buildout to minimize climate and safety risks associated with hydrogen production, storage, distribution, and use where it is used.

B. Hydrogen Production Source Category

Rapidly growing interest and investments in hydrogen, including billions of dollars in federal funding, will increase the prevalence of hydrogen production facilities and drive new forms of production that may not be encompassed in the existing source category definition. We recommend that EPA consider expanding the source category to include all forms of hydrogen production facilities, including those producing hydrogen through electrolysis or other less common methods. Even if these facilities are emitting lower or no greenhouse gas emissions, it is important that EPA gather activity data and information on energy consumption for this emerging sector to understand its impact on the overall energy mix and its role in decarbonization strategies.

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[42] Congressional Research Service, *Pipeline Transportation of Hydrogen: Regulation, Research, and Policy* at 1 (March 12, 2021), https://crsreports.congress.gov/product/pdf/R/R46700.
[43] *Id.* at 7; University of California, Riverside, *Final Report: Hydrogen Blending Impacts Study*, Prepared for California Public Utilities Commission (July 2022), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF.
[44] Section 60105 of the Inflation Reduction Act contains appropriations that could be used for these purposes. *See* Inflation Reduction Act of 2022, Pub. L. No. 117-169, § 60105, https://www.congress.gov/117/bills/hr5376/BILLS-117hr5376enr.pdf.

Currently, the hydrogen production source category is defined as:

> (a) A hydrogen production source category consists of facilities that produce hydrogen gas sold as a product to other entities.
>
> (b) This source category comprises process units that produce hydrogen by reforming, gasification, oxidation, reaction, or other transformations of feedstocks.
>
> (c) This source category includes merchant hydrogen production facilities located within another facility if they are not owned by, or under the direct control of, the other facility's owner and operator.[45]

EPA should consider amending this definition or clarifying through guidance or preamble text that it encompasses all forms of hydrogen production facilities, including those using electrolysis and any facility where emissions from hydrogen production are not reported through other categories. The existing definition may cause confusion in situations where the hydrogen produced is used onsite or otherwise not "sold as a product to other entities." While emissions from hydrogen production used onsite at refineries should be reported through that subpart, there may be uses beyond refining that would go unreported. We therefore recommend that EPA revise the definition as follows:

> (a) A hydrogen production source category consists of facilities that produce hydrogen gas as a product or a feedstock for other processes or products. ~~sold as a product to other entities~~.
>
> (b) This source category ~~comprises~~ includes but is not limited to process units that produce hydrogen by reforming, gasification, oxidation, reaction, electrolysis, or other transformations of feedstocks.
>
> (c) This source category includes ~~merchant~~ hydrogen production facilities located within another facility if emissions from hydrogen production are not reported by the larger facility under another subpart. ~~they are not owned by, or under the direct control of, the other facility's owner and operator~~.

By ensuring the source category adequately encompasses the various forms of hydrogen production that are likely to proliferate in coming years, EPA can ensure it is gathering the data to understand the climate and energy implications of this growing sector. Gathering emission data from hydrogen facilities that emit greenhouse gases and activity data from the sector more broadly will help EPA identify potential new emission sources and could inform future regulatory or non-regulatory approaches to minimize climate and air pollution impacts from hydrogen production. This information is also important for informing EPA's implementation of section 103 of the Clean Air Act regarding improvements in nonregulatory strategies and technologies for preventing or reducing air pollutants.

This source category should also encompass forms of production that use renewable energy as the primary input. Reporting on energy consumption, as discussed in section XI below, is necessary to inform

[45] 40 C.F.R. § 98.160.

decarbonization strategies. Green hydrogen may be important in hard-to-decarbonize sectors, like steel and shipping; however, the energy penalty makes direct electrification preferable for all end uses where electrification is possible. With every 1 kwh of renewable energy, using it to produce green hydrogen means only half of it (0.5 kwh) makes it into the produced hydrogen–the other half is lost through the process. And with limited renewable energy capacity, producing excessive amounts of green hydrogen may risk delaying fossil fuel retirement by diverting renewable energy from other uses. Understanding the electricity input for these forms of hydrogen production is central to evaluating their benefits. Additionally, were EPA to require reporting of emissions of hydrogen itself in future rulemakings, many of the producing facilities would already be subject to reporting requirements.

With these changes to the source category definition, our recommendations on energy consumption[46] would trigger requirements to report data on energy purchases by green hydrogen facilities that use as much energy as comparable SMR plants.[47] For example, in NREL's H2A Hydrogen Analysis Production Model, the modeled SMR plant without CCS emits 1,487,200 metric tons of CO2 per year.[48] The same plant produces 158,673,384 kg of H2 in a year, using 25,031,837 MMBtu of gas. Of that gas, 16.5% (4,130,000 MMBtu) is used as fuel and the rest is used as feedstock, according to this analysis (Table 3, Base Case, Specific Consumption).[49] The plant also uses 20,786,213 kWh (70,900 MMBtu) of electricity in a year.[50] So the unit's total annual energy use is about 4,200,000 MMBtu.[51] Scaling that number down to the size of a facility that emits 25,000 metric tons of CO2 in a year, which would trigger reporting under the current 40 C.F.R. § 98.2(a)(2), the energy input would be about 70,600 MMBtu. This is the value that would trigger reporting for green hydrogen production facilities under our recommended threshold described in section XI.

Applying that threshold to a typical electrolysis plant, we estimate that most would be subject to our proposed reporting on energy consumption. An electrolysis plant uses about 55.5 kWh (0.189 MMBtu) of electricity to produce a kilogram of hydrogen, according to NREL's H2A Lite Model.[52] So an electrolysis plant that uses 70,600 MMBtu per year (the suggested threshold for reporting) would produce about 373,545 kg hydrogen per year, which is a relatively low output.[53] Our recommended threshold based on energy input is therefore likely to capture most green hydrogen plants.

III. Subpart Q - Iron and Steel Production

We generally support EPA's proposed revisions to subpart Q, and provide some suggestions for further refinements. We agree with EPA that the annual production capacity in combination with annual operating

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[46] *See infra* section XI on energy consumption.
[47] *See id.*
[48] NREL, *H2A: Hydrogen Analysis Production Models*, https://www.nrel.gov/hydrogen/h2a-production-models.html.
[49] Collodi et al., *Techno-economic Evaluation of Deploying CCS in SMR Based Merchant H2 Production with NG as Feedstock and Fuel*, 114 Energy Procedia 2690, 2707, Table 3, Base Case, Specific Consumption (2017), https://www.sciencedirect.com/science/article/pii/S1876610217317277.
[50] *Id.*
[51] *Id.*
[52] NREL, *supra* note 48.
[53] *See, e.g.*, Johanna Ivy, Summary of Electrolytic Hydrogen Production, NREL/MP-560-36734 (2004), https://www.nrel.gov/docs/fy04osti/36734.pdf.

hours would provide useful information for understanding variations in annual emissions and would help to verify reported data. This data would provide useful information to understand trends across the sector and support analysis of these sources. EDF therefore supports EPA's proposal to require that facilities report the type of unit and the annual production capacity of each unit.

However, as proposed, the use of the term "annual production capacity" is confusing because the word "capacity" can sometimes mean the rating or design capacity of the unit as opposed to the available or actually utilized capacity of the unit during the specific time period. Since the goal of the reporting program is to provide estimates of actual emissions and the goal of including these additional parameters is to enable EPA to readily compare reported emissions across various time periods (and thereby understand changes over time), EPA should ask facilities to report actual production levels (not capacity) from each unit. For example, if the production capacity of an EAF is 800,000 tons of steel per year, but the actual production level was 600,000 tons of steel from that EAF, we presume that EPA would be interested in the latter and not the former. Thus, asking for the actual production level and not the production capacity would be a better approach. Second, while we support the collection of actual operating hours for each unit, that information will not provide any additional value in estimating annual emissions since the annual emissions will depend on the annual production level we have noted prior.

EDF supports EPA's proposal for facilities to determine the carbon content of process inputs and outputs using analyses provided by material recyclers that manage process outputs for sale or use by other industries. However, we have some concerns and suggestions for improvements. We also urge EPA to clearly designate this new option as a last resort for reporting.

First, we note that EPA should require, to the maximum extent possible, that the primary responsibility for determination of the carbon contents of each of the terms used in each of the equations Q-1 through Q-8 in 40 C.F.R. § 98.173 rest with the facility operator instead of a supplier (as currently allowed) or a material recycler (as would be enabled by the new option). While an operator can obtain carbon content data from suppliers or recyclers, it is not always true that that data is representative of the carbon contents at each facility. For example, a supplier (to multiple operating facilities) may provide a range of carbon contents or perhaps an average carbon content – neither or which may apply to the facility. Obtaining average values of carbon contents for certain types of materials (such as, say, steel scrap) may be significantly erroneous unless there is a one-to-one relationship between the supplier and the operator. That is rarely the case. Similarly, a downstream recycler may obtain materials from several operators and simply provide all of them with an average value of carbon content, which would not represent the carbon contents for any of the facilities. Thus, while sources such as suppliers or recyclers are potentially useful, they cannot be as accurate as the first option – namely the use of site-specific determinations by the operator. EPA should clarify this clearly and indicate a strong preference that option one is to be used; and while other options (suppliers and recyclers) can be sources of such data, it is the responsibility of the operator to attest to the accuracy of such third-party carbon content data, for their specific facility.

Second, EPA notes that it "determined that the use of carbon content analyses from a material supplier was appropriate because the carbon content does not vary widely at a given facility . . . ."[54] EPA does not provide any basis for this unsupported, conclusionary, statement. As a simple inspection of the parameters for

[54] 87 Fed. Reg. at 36,960.

equations Q-1 through Q-8 in 40 C.F.R. § 98.173 confirms, there are a wide range of carbon-containing inputs, products, byproducts, and waste materials, depending on the specific unit type covered in these equations. To presume, for all of the various materials, that their carbon content "does not vary widely" without data, is inappropriate. To the contrary, there can be significant variations in the carbon contents of these various materials in most instances for many reasons, including the fact that at most iron and steel mills multiple grades of products (using multiple types of recipes) can be made. This is particularly true of steel making; for example, at an EAF several hundred product grades can be made from the various heats – all from the same furnace. EPA's presumption is therefore incorrect.

Third, and related to the second, EPA presumes that variations in greenhouse gas emissions are accounted for due to changes in the production rate, which are more likely to vary. While production rates do vary and can clearly affect emissions, we note that EPA is not asking facilities to report the production levels for each and every grade of product made at a facility annually, for example. In fact, EPA incorrectly presumes that each ton of product made is similar. EPA's presumption that the overall (i.e., without regard to grade) production level captures most of the variability – underlying a further presumption that carbon contents of various materials do not vary as much – is overly simplified. We recognize that accounting for each grade or product made and its emissions – in effect applying equations Q-1 through Q-8, as applicable, on a grade-by-grade basis and then summing the results for all grades made in the reporting period – is unwieldy and some degree of simplification is administratively necessary. But EPA goes too far in its claims about how and where carbon-content and/or production variability affects emissions. EPA should support or remove these statements.

EDF also supports the proposal to correct Equation Q-5 to remove the unnecessary fraction symbol. This change corrects an obvious error in how equation Q-5 is shown in 40 C.F.R. § 98.173(b)(1)(v). The inclusion of the divisor line in the equation is a conspicuous but unambiguous error that is unlikely to have caused any actual reporting issues. But, we support correcting it and removing the confusing horizontal "divisor" line in equation Q-5. Finally, EDF supports the proposed addition of ASTM method E415-17, Standard Test Method for Analysis of Carbon and Low-Alloy Steel by Spark Atomic Emission Spectrometry (2017).

IV. Subpart W - Petroleum and Natural Gas Systems

In this section, we first explain the urgent need for and importance of EPA comprehensively updating subpart W to satisfy the recent congressional directive in the Methane Emissions Reduction Program (MERP), followed by recommendations for those updates. We encourage EPA to move forward with these congressionally mandated updates in the context of completing this proposed rulemaking to ensure that the required comprehensive updates are completed within the two-year timeline Congress has mandated. We anticipate, however, that doing so will require EPA to issue a supplemental proposal, given that the June 21, 2022 proposal was issued prior to the adoption of MERP and does not propose sufficiently comprehensive updates to implement Congress' new directives in MERP.

Next, we set forth our recommendations for improvements related to the changes EPA has already proposed. There is an urgent need to build on and strengthen the subpart W reporting requirements, which numerous field studies have shown significantly underestimate actual methane emissions from the oil and gas sector. While data currently reported through subpart W is valuable for understanding source-level emissions, and EPA should continue to improve source-level reporting requirements, this data does not accurately characterize total emissions from the oil and gas sector. Recent technological developments, scientific evidence, congressional action, and industry recognition and commitments underscore the need to substantially revise subpart W to ensure reported emissions accurately reflect actual observed emissions.

A. MERP Congressional Directive

On August 16, 2022, President Biden signed into law the Inflation Reduction Act, in which Congress created a new Clean Air Act section 136, containing MERP.[55] The new section directs EPA to revise the GHGRP provisions that apply to the oil and gas sector to ensure that reporting is based on accurate and empirical emissions data. With this directive, Congress clearly indicated that it did not believe that the current reporting requirements meet the specified threshold and that EPA would need to conduct a rulemaking to implement the necessary revisions. It is fortuitous that EPA had quite recently initiated a broader rulemaking to update the GHGRP across a swathe of industry sectors, and thus EPA already has a vehicle underway that could include the revisions required by the new law. In giving EPA a two-year deadline for revising the regulations, Congress established a short timeline for final action, consistent with the understanding that the update was necessary to provide incentives to reduce the waste that is actually occurring, but much of which is not reported under the current regulations. Consistent with that short timeline for the rulemaking, EPA should take advantage of the fact that it has already initiated a rulemaking on the oil and gas reporting requirements and include the necessary updates to address the MERP directives in the course of this rulemaking.

We emphasize, however, that just the narrow updates in the June 21, 2022 proposal would, if finalized, in no way satisfy Congress' directive to ensure the use of accurate and empirical emissions data in reporting and as the basis for the waste charge. Thus, we discuss below the broader set of changes that are necessary to implement MERP, as well as respond to the narrower set of issues that were raised in the June 21, 2022 proposal. While our proposed broader changes outlined in Part B below are necessary to satisfy the congressional directive, updating source-level reporting requirements is also important, and we therefore comment on these proposed changes as well in Parts C through O.

Section 136(h) directs EPA to update subpart W of the GHGRP to ensure reporting is (1) "based on empirical data," (2) "accurately reflect[s] the total methane emissions" from reporting facilities, and (3) allows reporting facilities "to submit empirical emissions data."[56] EPA must satisfy each of these components to meet Congress's directive and fulfill the intent of the legislation. "Empirical data" and "accurately reflect the total" are central terms and phrases that must be given effect when revising subpart W. The current subpart W reporting requirements that Congress has found inadequate for estimating total emissions use historical engineering calculations and emission factors derived from old studies. To update this approach so as to use empirical data and accurately capture the total quantity of emissions, EPA should rely on empirically based and validated probabilistic models. This will require EPA to develop and use empirical characterizations of emissions distributions as well as top-down validation data and methods. In enacting MERP, Congress recognized that the necessary improvements were sufficiently significant to

[55] Inflation Reduction Act of 2022, Pub. L. No. 117-169, § 60113, https://www.congress.gov/117/bills/hr5376/BILLS-117hr5376enr.pdf.
[56] *Id.*

require additional resources for EPA and appropriated $1.55 billion to help implement the program, a portion of which is allowed to be, and should be, used by EPA to fulfill this directive.[57]

MERP does not define "empirical data," so the term takes its ordinary meaning, informed by the statutory context.[58] Plain meaning and context, including the well-documented underestimation of subpart W, make clear that the current emission factor-based reporting methodology does not reflect empirical data.[59] "Empirical" means "originating in or based on observation or experience" and "capable of being verified or disproved by observation or experiment."[60] And, "empirical data" or "empirical evidence" means data which "relies on practical experience rather than theories"[61] and is "derived from reliable measurement or observation."[62] Methane emission estimates based on emission factors that numerous field studies have shown are not representative of current conditions do not constitute empirical data within the meaning of the new statutory provision. Instead, empirical data in the context of subpart W should be understood to mean statistically robust data based on scientifically rigorous measurements of representative sources.

MERP also requires that the revisions ensure reporting accurately reflects total methane emissions from reporting facilities. It requires EPA to "revise the requirements of subpart W . . . to ensure the reporting under such subpart, and calculation of [the methane waste charge], . . . accurately reflect the total methane emissions and waste emissions from the applicable facilities[.]"[63] To accurately calculate "total" emissions from a facility using the best available scientific methods requires taking representative site-level measurements of actual emissions. The site-level estimates can then be used to determine the overall facility emissions. Only when reported emissions closely align with total observed emissions can MERP be accurately implemented.[64]

As explained in more detail in the following sections, there is a significant body of scientific evidence based on field observations and measurement data demonstrating that total observed emissions are far higher than emissions currently reported to subpart W and emission inventory estimates. In order for subpart W reporting requirements to be revised consistent with Congress's requirement of accuracy, reported emissions must better align with actual emissions observed in the field. This requires revisions beyond what EPA has proposed thus far.

EPA's proposed updates do include some improvements that would incorporate measurement data, but these changes are modest, voluntary, and do not satisfy the Congressional directive in section 136(h).

[57] *See id.* at § 136(a)(4) (directing a portion of the $1.55 billion appropriation "to cover all direct and indirect costs required to administer this section, prepare inventories, gather empirical data, and track emissions.").
[58] *Kouichi Taniguchi v. Kan Pac. Saipan, Ltd.*, 566 U.S. 560, 566 (2012).
[59] Alvarez et al., *Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain*, 361 Science 186 (2018), https://science.sciencemag.org/content/361/6398/186; Rutherford et al., *Closing the Methane Gap in US Oil and Natural Gas Production Emissions Inventories*, 12 Nature Comms. 4715 (2021), https://www.nature.com/articles/s41467-021-25017-4#citeas.
[60] Merriam-Webster, *Definition of Empirical*, https://www.merriam-webster.com/dictionary/empirical.
[61] Collins Dictionary, *Empirical Data*, https://www.collinsdictionary.com/us/dictionary/english/empirical-data.
[62] Your Dictionary, *Empirical Data*, https://www.yourdictionary.com/empirical-data. Empiricism is the concept that knowledge is acquired through observation and experience rather than purely through logic.
[63] 42 U.S.C. § 7436(h).
[64] *See, e.g.*, Comment Submitted by Kairos Aerospace, at Figure 1 (Sept. 15, 2022), Docket No. EPA-HQ-OAR-2019-0424, https://www.regulations.gov/comment/EPA-HQ-OAR-2019-0424-0176 (showing large discrepancies in anonymized operator methane intensities calculated using GHGRP data versus aerially observed emissions).

Accordingly, we respectfully urge EPA to build on its current proposal by issuing a supplemental proposal to revise subpart W more comprehensively, integrating site-level direct measurement data and top-down validation methods.[65] Proceeding in this fashion will best leverage EPA's improvements in the rulemaking already underway and ensure EPA meets Congress's directive to update subpart W by August 2024 at the latest. Below we offer recommendations that could inform a supplemental proposal along these lines.

B. MERP Implementation: Accurate, Empirically Based Site-Level Estimates

To ensure reporters accurately estimate total emissions, we recommend that EPA rely on site-level data when updating subpart W to implement MERP. EPA's current approach allows reporters to estimate source-level emissions based primarily on engineering calculations and default emission factors. Source-level emission estimates provide valuable information to support regulations mitigating emissions, although they are less useful for estimating total emissions from sites and facilities since many emissions are from abnormal conditions that are difficult to categorize as a specific source. The under-reporting that occurs through the existing source-level-only approach would undermine the effectiveness of MERP, which is consistent with Congress's inclusion of a directive to update subpart W as part of the same bill. EPA should build from and add to its existing approach in a manner that utilizes two additional types of empirical data: scientifically robust site-level measurements of representative sites; and independent emission estimates based on atmospheric observations at the basin or sub-basin level (top-down measurement approaches).

To do this, we recommend a three-step process that is described in more detail below. First, EPA should compile representative site-level measurement data by major production basin. Second, EPA should work with other relevant federal agencies to develop independent, routine, top-down estimates of total emissions by major production basin. And third, EPA should reconcile the two data sets to generate default site-level emission estimates to be used by reporters for the purposes of implementing MERP. Reporters could also follow EPA-defined protocols for collecting and submitting their own measurement data to demonstrate emissions lower than the site-level defaults.

This multiscale approach will ensure subpart W reporting is accurate, within the meaning of MERP, by not only ensuring that site-level measurements are reconciled to match total regional emissions, but critically that the approach is able to capture changes in emissions over time. As the industry reduces emissions, those reductions will be captured in the GHGRP, which is not currently the case with respect to certain kinds of emission reductions. Such an approach will also incentivize improved methane monitoring and the use of advanced technologies.

Several scientific studies[66] across the oil and gas supply chain have shown that emissions are seldom normally distributed—with a small fraction of sites having a disproportionately large contribution to total

[65] In other areas where the recently-passed Inflation Reduction Act has affected an ongoing rulemaking, EPA has proceeded in similar fashion. *See, e.g.*, David Shepardson, *U.S. EPA to consider tougher emissions rules for heavy trucks* (Sept. 21, 2022), https://www.reuters.com/business/sustainable-business/exclusive-us-epa-consider-tougher-emissions-rules-heavy-trucks-2022-09-21/ (EPA indicated would issue a supplemental proposal to consider the impacts of the IRA on its proposed standards for heavy-duty vehicles and noted that "Congress definitely sent a very strong message backed by significant resources.").

[66] Brandt et al., *Methane Leaks from Natural Gas Systems Follow Extreme Distributions* (2016), https://pubs.acs.org/doi/10.1021/acs.est.6b04303 ; Gorchov Negron et al., *Airborne Assessment of Methane Emissions from Offshore Platforms in the U.S. Gulf of Mexico* (2020), https://pubs.acs.org/doi/10.1021/acs.est.0c00179; Marchese et al., *Methane Emissions from United States Natural Gas Gathering and Processing* (2015), https://pubs.acs.org/doi/10.1021/acs.est.5b02275; von Fischer et al., *Rapid, Vehicle-Based Identification of Location*

emissions. This means that any statistical treatment will need to include sufficient data to accurately account for the characteristics of the "heavy-tailed" emission distribution. Previous studies have demonstrated how site-level measurements can be extrapolated to regional emissions with statistical methods and then reconciled with basin-level top-down data to provide insights into key sources of emissions not previously fully captured in estimates.[67] While these methods will not provide information on the emissions of a particular site at a given time, they do accurately characterize the emissions of a population of sites and so should be the basis for determining "facility" level emissions in subpart W.

EPA's recently proposed updates to subpart W—which preceded the passage of MERP—would revise certain emission factors based on recent studies and create a new category of reported emissions called large release events (those greater than 10 $mtCH_4$). Characterizing and quantifying emissions from large release events is necessary but not sufficient for accurately estimating total emissions. It is critical that EPA assess whether the emission estimates are accurately and fully capturing both ends of the aggregate emissions distribution. The proposed updates may better characterize the heavy-tailed emission distribution but will miss a significant portion because most of those emissions are not sufficiently large to be reported as "large release events." Until these somewhat smaller but cumulatively very significant emissions are accounted for, the subpart W estimates will not be accurate.

Top-down measurement-based approaches are able to constrain total oil and gas emissions at the regional scale and are readily available for widespread deployment.[68] When performed routinely, they provide the necessary assurance that GHGRP aggregated emissions are accurately capturing all sources of emissions and are also reflecting emissions changes over time. There are also well-established methods of excluding methane emissions from non-oil and gas sources, and deploying these will be important to meeting the criteria for accuracy at varying degrees depending on the oil and gas production basin.

and Magnitude of Urban Natural Gas Pipeline Leaks (2017), https://pubs.acs.org/doi/full/10.1021/acs.est.6b06095; Zavala-Araiza et al., *Super-emitters in Natural Gas Infrastructure Are Caused by Abnormal Process Conditions*, 8 Nat. Comms. 14012—1421 (2017), https://www.nature.com/articles/ncomms14012 [hereinafter "Zavala-Araiza 2017"].

[67] Alvarez et al., *supra* note 59; Omara et al., *Methane emissions from US low production oil and natural gas well sites*, 13 Nat. Comms. 2085 (2022), https://www.nature.com/articles/s41467-022-29709-3; Robertson et al., *New Mexico Permian Basin Measured Well Pad Methane Emissions Are a Factor of 5—9 Times Higher than U.S. EPA Estimates*, 54 Env. Sci. Tech. 13926—13934 (2020), https://pubs.acs.org/doi/abs/10.1021/acs.est.0c02927; Zavala-Araiza 2017, *supra* note 66.

[68] Barkley et al., *Quantifying methane emissions from natural gas production in north-eastern Pennsylvania* (2017) https://doi.org/10.5194/acp-17-13941-2017; Lyon et al., *Concurrent Variation in Oil and Gas Methane Emissions and Oil Price During the COVID-19 Pandemic* (2021), https://acp.copernicus.org/articles/21/6605/2021/; Lin et al., *Declining Methane Emissions and Steady, High Leakage Rates Observed over Multiple Years in a Western US oil/gas Production Basin* (2022), https://www.nature.com/articles/s41598-021-01721-5; Karion et al., *Aircraft-Based Estimate of Total Methane Emissions from the Barnett Shale Region* (2015), https://pubs.acs.org/doi/full/10.1021/acs.est.5b00217; Peischl et al., *Quantifying Atmospheric Methane Emissions from the Haynesville, Fayetteville, and Northeastern Marcellus Shale Gas Production Regions* (2015), https://agupubs.onlinelibrary.wiley.com/doi/full/10.1002/2014JD022697; Shen et al., *Satellite Quantification of Oil and Natural Gas Methane Emissions in the US and Canada Including Contributions from Individual Basins* (2022), https://acp.copernicus.org/articles/22/11203/2022/; Schwietzke et al., *Improved Mechanistic Understanding of Natural Gas Methane Emissions from Spatially Resolved Aircraft Measurements* (2017), https://pubs.acs.org/doi/10.1021/acs.est.7b01810.

Previous scientific studies have described how site-level data can be statistically aggregated and reconciled with basin-level top-down estimates.[69] Studies have also shown how this multi-scale reconciled data can then be used to assess completeness and improvements to source-level inventories.[70] Discrepancies between bottom-up and top-down estimates provide information about larger uncertainties in terms of magnitude and location of emissions and help identify key sources that require further characterization and attention.[71] This reconciliation is also integral to meeting the requirements set out under MERP by ensuring the subpart W data is accurate, not systematically skewed as is currently the case. Reconciliation is also necessary to ensure subpart W data is empirically-based to ensure that changes in emissions are rapidly reflected in the reported emissions, unlike the current case where shifts in emissions are largely not included.

To implement the MERP directive, we recommend EPA develop site-level emission factors that would serve as the basis for reporting alongside EPA's existing source-based approach. To ensure these site-level estimates are both empirically based and accurately reflect total emissions, we recommend that EPA follow the three-step approach described above and included in more detail below:

1. **EPA should oversee the collection of site-level measurement-based estimates.** This measurement data must be stratified randomly within regions, industry segments, operator ownership, and types of sites to ensure representativeness. The number of samples should be sufficient to fully characterize—in the aggregate—the populations of emission sources. EPA must also define what high quality population-level empirical data it will accept. The site-level measurement data should then be used to develop probabilistic, population-based models that characterize the entire emission distribution and extrapolate data to aggregate regional emissions.

2. **Independently quantify total oil and gas emissions at the basin/sub-basin level.** EPA should work with other federal agencies (e.g., NOAA) to perform , coordinate, and oversee routine top-down measurements covering most oil and gas producing regions that account for the overwhelming majority of oil and gas production. Top-down estimates would have independent utility beyond subpart W, including for the improvement of the Greenhouse Gas Inventory (GHGI). Top-down approaches should be based on a set of previously peer-reviewed, scientifically robust approaches including aircraft,[72] towers,[73] and satellites.[74] Top-down approaches should incorporate robust attribution methods[75] that allow for separating emissions between oil and gas and other methane sources.

[69]Alvarez et al., *supra* note 59; Zavala-Araiza et al., *Toward a Function Definition of Methane Super-Emitters: Application to Natural Gas Production Sites*, 49 Env. Sci. Tech. 8167 (2015), https://pubs.acs.org/doi/pdf/10.1021/acs.est.5b00133.

[70] Rutherford et al., *supra* note 59; Zavala-Araiza et al., *supra* note 66.

[71] Alvarez et al., *supra* note 59; Neininger et al., *Coal Seam Gas Industry Methane Emissions in the Surat Basin, Australia: Comparing Airborne Measurements with Inventories* (2021), https://royalsocietypublishing.org/doi/10.1098/rsta.2020.0458; Shen et al., *Satellite Quantification of Oil and Natural Gas Methane Emissions in the US and Canada Including Contributions from Individual Basins* (2022), https://acp.copernicus.org/articles/22/11203/2022/.

[72] *See, e.g.*, Karion et al., *supra* note 68; Peischl et al., *supra* note 68; Schwietzke et al., *supra* note 68.

[73] *See, e.g.*, Monteiro et al., *Methane, carbon dioxide, hydrogen sulfide, and isotopic ratios of methane observations from the Permian Basin tower network* (2022), https://essd.copernicus.org/articles/14/2401/2022/.

[74] *See, e.g.*, Shen et al., *Unravelling a large methane emission discrepancy in Mexico using satellite observations* (2021), https://www.sciencedirect.com/science/article/pii/S0034425721001796?via%3Dihub.

[75] Smith et al., *Airborne Ethane Observations in the Barnett Shale: Quantification of Ethane Flux and Attribution of Methane Emissions* (2015), https://pubs.acs.org/doi/full/10.1021/acs.est.5b00219.

3. **Reconcile the site-level data from (1) with the quantified basin/sub-basin level data from (2).** The reconciled data provides new site-level emission factors used by reporters which are then used to implement MERP. Operators are able to submit their own site-level measurement-based data—subject to specific requirements about data quality and previous validation of measurement methods—to prove their company-level facility-based emissions are lower than the population average. Company-submitted data must be considered when the general basin level emission factor is calculated to ensure that there is alignment with the top-down estimates and basin-level accuracy is maintained. In other words, if emission factors for one group of facilities goes down the factors for other facilities must go up to ensure conservation of mass and thereby meet the accuracy requirement.

By adopting these recommendations, EPA can implement MERP's directive to ensure subpart W reporting is empirically-based, accurate, and allows operators to submit empirical data. We note that EPA has a near-term opportunity to ensure representative site-level data, including through additional collection of information and leveraging existing, high-quality emissions data.

Our recommendations here also have implications for EPA's source-level estimates. For purposes such as rulemakings that require source-level data, EPA could eventually reconcile the empirical estimates of total emissions derived through the process outlined above with source-level estimates.[76] But EPA can also improve source-level reporting through the already proposed updates to subpart W. In the following sections, we comment on those updates and others EPA has proposed in this rulemaking.

C. The Significant Problem of Underestimation[77]

Emission estimates derived from data reported through subpart W have traditionally lead to significant underestimation of total emissions from the oil and gas sector, with the greatest divergence in the production segment.[78] A large body of peer-reviewed literature has documented this failure to fully capture emissions over the past decade, primarily attributing the divergence to the GHGRP and Greenhouse Gas Inventory's (GHGI) failure to account for intermittent, large emission events. These emissions, often termed "super-emitters," are commonly caused by abnormal process conditions and equipment failures. Super-emitters lead to a heavy-tailed emission distribution, where the top 5-10% of sites or components are responsible for around 50% of total emissions. Below we summarize the literature documenting these emissions across the oil and gas sector.

Super-emitters are generally considered within the category of fugitive emissions, but they are distinct due to their root causes, large magnitude, and stochasticity. Fugitive emissions are emissions that are not

[76] To do this, EPA could compare estimates of total basin-level emissions based on the current approach of engineering calculations and source-level emission factors to empirically derived estimates. It could then use the empirically derived estimates described in (1) to (3) as the official value for total emissions and assign the difference in emission estimates to a generic source category (e.g., uncategorized). And finally, EPA could assess which source estimates are the likely cause of discrepancies using statistical methods and basin-level comparisons and update source-level methods to increase their accuracy.
[77] The remaining portions of our comments on subpart W were developed in collaboration with Clean Air Task Force and contain similar recommendations.
[78] *See, e.g.*, Alvarez et al., *supra* note 59; Rutherford et al., *supra* note 59.

intended as part of normal operations and can be broadly classified as leaks and unintentional vents. Sources of fugitive emissions include valves, flanges, connectors, thief hatches of controlled tanks, pump diaphragms, seals, and open-ended lines, and many others. Causes of these emissions include persistent issues, such as equipment malfunctions (e.g., unlit flare), as well as intermittent, short duration events (e.g., flashing from condensate tanks with malfunctioning controls).[79] Fugitive emissions can also result from devices that vent as part of normal operations, such as natural-gas driven pneumatic controllers, and control devices or equipment combusting natural gas, such as flares, when those devices are not operating as intended and have abnormally high emission rates. Fugitive emissions that result from abnormal operating conditions or equipment failures and result in large emission events are termed "super-emitters."

Super-emitters are often not well-represented (and may not be represented at all) in official estimates and inventories because they can be intermittent and are easily missed when taking equipment- or component-level measurements.[80] Because of this, emission factors derived from such measurements that do not otherwise account for super-emitters are not representative of total observed emissions. Bottom-up methods that estimate emissions using component or equipment counts and emission factors often fail to account for super-emitter events and result in artificially low overall emission estimates. Bottom-up methods often rely on measurements that capture only a snapshot of time; therefore, they may not be representative of emissions over longer timescales and are likely to miss intermittent emissions. Additionally, emission estimates that rely on engineering calculations often fail to account for super-emitters because the data inputs assume normal operations. Aerial detection methods and other top-down measurement and quantification techniques have documented the significance of large emission events and their large contribution to total emissions. This well-documented, heavy-tailed emission distribution means that 5-10% of sites are often responsible for 50% or more of total emissions.

Over the last decade, research by EDF and others has quantified the significance of methane emissions caused by oil and gas production and the persistent underestimation of fugitive and abnormal process emissions.[81] A large body of measurement-based studies has consistently found higher oil and gas methane emissions than are reflected in most inventories.[82] Bottom-up approaches like the EPA inventory and the subpart W reporting protocols greatly underestimate emissions because they are based on assumptions that do not account for large events caused by malfunctions and other abnormal conditions.[83] Accounting for

[79] Zavala-Araiza et al., *Toward a Function Definition of Methane Super-Emitters: Application to Natural Gas Production Sites*, 49 Env. Sci. Tech. 8167 (2015), https://pubs.acs.org/doi/pdf/10.1021/acs.est.5b00133.
[80] *See* IEA, *Methane Tracker Database* (Oct. 2021), https://www.iea.org/articles/methane-tracker-database (summary of inventory estimates).
[81] EDF, Methane Research Series: 16 Studies, https://www.edf.org/climate/methane-research-series-16-studies.
[82] Lyon et al., *Concurrent Variation*, *supra* note 68; Zavala-Araiza et al., *Reconciling Divergent Estimates of Oil and Gas Methane Emissions*, 112 Proc. Natl. Acad. Sci. 15597–15602 (2015), https://www.pnas.org/doi/abs/10.1073/pnas.1522126112; Zavala-Araiza et al., *supra* note 66; Zimmerle et al., *Methane Emissions from the Natural Gas Transmission and Storage System in the United States*, 49 Env. Sci. Tech. 9374–9383 (2015),https://pubs.acs.org/doi/10.1021/acs.est.5b01669; Omara et al., *Methane Emissions from Conventional and Unconventional Natural Gas Production Sites in the Marcellus Shale Region*, 50 Env. Sci. Tech. 2099—2107 (2016), https://pubs.acs.org/doi/10.1021/acs.est.5b05503; Peischl et al., *supra* note 68; Caulton et al., *Importance of Superemitter Natural Gas Well Pads in the Marcellus Shale*, 53 Env. Sci. Tech. 4747—4754 (2019), https://pubs.acs.org/doi/10.1021/acs.est.8b06965; Robertson et al., *supra* note 67; Zhang et al., *Quantifying Methane Emissions from the Largest Oil-producing Basin in the United States from Space*, 6 Sci. Adv. 5120 (2020), https://advances.sciencemag.org/content/6/17/eaaz5120/tab-pdf; Lyon et al., *Concurrent Variation*, *supra* note 68.
[83] Rutherford et al., *supra* note 59.

these emission events can increase inventory estimates by 60-70%, underscoring the importance of accurate reporting protocols that capture such emissions.[84]

In 2012, EDF launched a series of research studies to quantify methane emissions from the U.S. oil and gas supply chain with diverse, measurement-based methodologies.[85] This collaborative work with over one hundred and forty experts from academia, industry, and government has resulted in more than forty peer-reviewed papers. In 2018, Alvarez et al., synthesized previous studies to estimate that U.S. oil and gas supply chain methane emissions were 13 million metric tons in 2015, equivalent to 2.3% of natural gas production and about 70% higher than estimated by EPA's current GHGI.[86] Numerous other studies have confirmed that bottom-up approaches like the GHGI and the subpart W reporting protocols greatly underestimate oil and gas methane emissions, largely capturing only component-level leaks and often missing the largest emission events.[87]

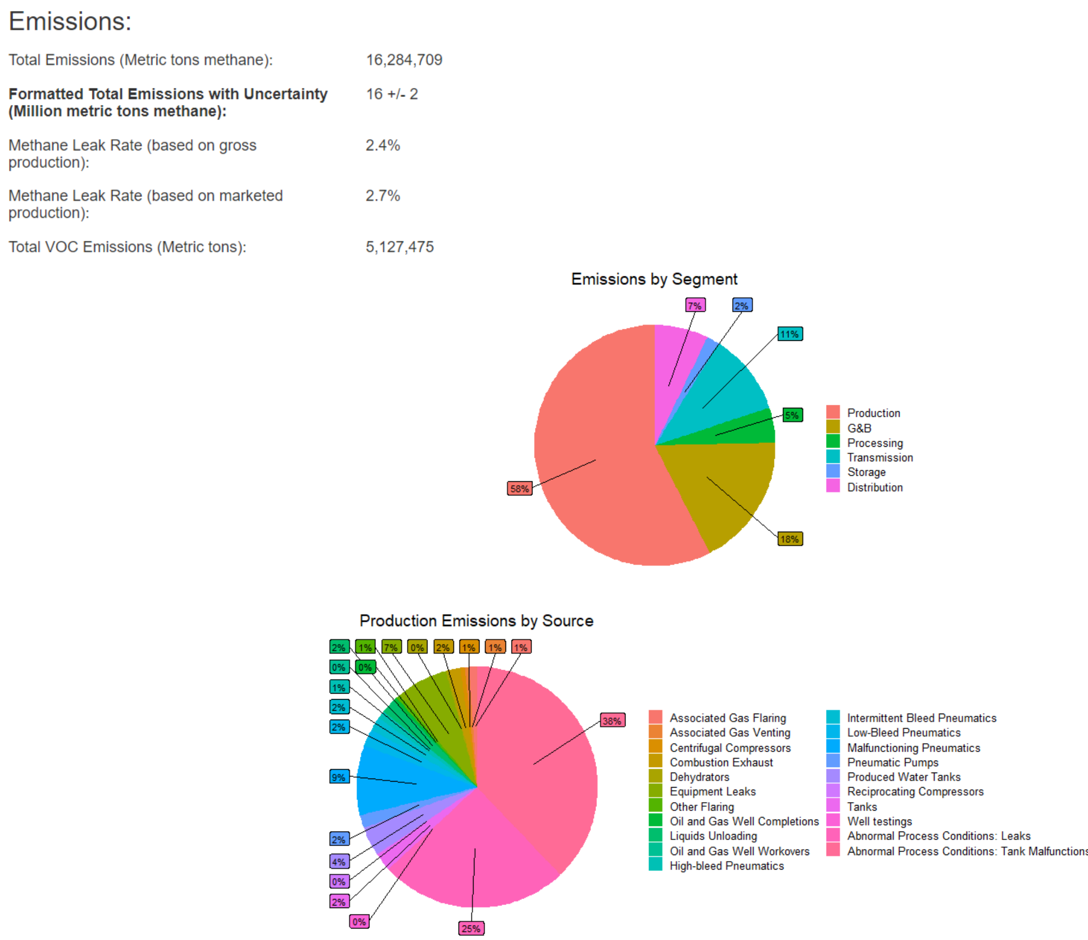

Figure 2: Alvarez Synthesis Model Inventory Estimates[88]

[84] Alvarez et al., *supra* note 59.
[85] *See* EDF, Methane research series: 16 studies, https://www.edf.org/climate/methane-research-series-16-studies.
[86] Alvarez et al., *supra* note 59.
[87] *See, e.g.*, Rutherford et al., *supra* note 59.

Recent research has found several common characteristics of oil and gas industry methane emissions. First, emissions occur across the value chain from well to end use, but are concentrated in the production and gathering segments, including well pads, tank batteries, and gathering compressor stations. EDF's emission inventory (shown above), derived from the Alvarez synthesis model and using more recent activity data,[89] estimates that production segment fugitive emissions represent nearly 50% of all oil and gas sector methane emissions. Second, all oil and gas facility types have a skewed distribution in which 5-10% of the highest emitting sites are responsible for about half of total emissions; however, the identity of these high-emitting sites can change with time and is difficult to predict.[90] Third, low production or marginal wells tend to have lower absolute emissions than high production wells, but much higher loss rates as a percentage of gas production. And because roughly three quarters of all wells are marginal, they cumulatively contribute a substantial fraction to total emissions–around 50% of production sector emissions according to a recent study.[91] Fourth, emissions can almost always be mitigated once detected, sometimes with a simple repair to stop a leak, and other times by implementing operational or equipment changes that improve a site's efficiency.

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

Zhang et al. in a 2020 paper estimate the Permian Basin loss rate is 3.7% of gas production, substantially higher than the national average.[92] In 2021, Lyon et al., found a similar loss rate of 3.3% in the core production area of the Delaware sub-basin in March 2020 using aircraft and tower-based measurements. Lyon et al. report that the loss rate temporarily dropped to 1.9% in April 2020 when oil prices declined but recovered to prior levels by summer 2020.[93] They hypothesize that the Permian Basin typically has a high loss rate because wells are developed faster than the pipelines and compressor stations needed to transport the gas to market. This leads to both high rates of associated gas flaring and abnormal emissions due to gathering systems with inadequate capacity. The decline in well development during low oil prices likely temporarily relieved capacity issues and reduced emissions, bringing the leak rate closer to but still higher

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[88] For an explanation of the methodology used to create this inventory, *see* EDF, *2019 U.S. Oil & Gas Methane Emissions Estimate*, http://blogs.edf.org/energyexchange/files/2021/04/2019-EDF-CH4-Estimate.pdf

[89] EDF, *2019 U.S. Oil & Gas Methane Emissions Estimate*, http://blogs.edf.org/energyexchange/files/2021/04/2019-EDF-CH4-Estimate.pdf; *see also* IEA, *Methane Tracker Database* (Oct. 2021), https://www.iea.org/articles/methane-tracker-database (summarizing and comparing various inventory estimates).

[90] Lyon et al., *Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites*, 50 Env. Sci. Tech. 4877 (2016), https://pubs.acs.org/doi/full/10.1021/acs.est.6b00705.

[91] Omara et al., *Methane Emissions from US Low Production Oil and Natural Gas Well Sites*, 13 Nat. Comms. 2085 (2022), https://www.nature.com/articles/s41467-022-29709-3; *see also* EDF, *Marginal Well Factsheet* (2021), https://www.edf.org/sites/default/files/documents/MarginalWellFactsheet2021_0.pdf.

[92] Zhang et al., *supra* note 82.

[93] Lyon et al., *Concurrent Variation*, *supra* note 68.

than EPA inventory estimates. This study suggests that permanent reductions could be achieved by ensuring adequate gathering infrastructure before permitting new well development.

Robertson et al. in a 2020 paper determined that New Mexico Permian well pad emissions were five to nine times higher than EPA inventory estimates; complex pads including tanks or compressors had about twenty times higher average emissions than simple pads with only a wellhead.[94] Finally, Cusworth et al. in 2021 used an aerial remote sensing approach to quantify over 1,100 large methane sources in the Permian.[95] In support of previous research, the paper found that both the gathering sector and flares are large sources of emissions. They also assess the intermittency of large sources and determine that, on average, large emission sources are emitting 26% of the time.

In addition to quantifying methane emissions, EDF scientists have assessed flare performance in the Permian with a series of helicopter-based infrared camera surveys. Based on over one thousand flare observations, approximately 5% of large flares are unlit and venting gas at any given time, and another 5% have visible slip of methane or other hydrocarbons–meaning the flare is only partially combusting the methane and the rest is escaping to the atmosphere. On-the-ground flare combustion efficiency is thus much worse than EPA has assumed and than regulatory standards require. Flares are consequently one of the largest sources of methane in the Permian Basin, and the latest surveys have found even worse performance among smaller, intermittent flares.[96] These findings suggest that reported flare emission estimates are likely far lower than actual emissions.

Studies examining emissions from low-producing or marginal wells—those that produce an average of less than 15 BOE/day—find even greater leak rates. And because there are hundreds of thousands of these sites nationwide, the cumulative emissions are very problematic and may represent more than half of total production-segment emissions.[97] In West Virginia, researchers found that wellhead methane emissions from marginal wells were 7.5 times larger than EPA's inventory estimate, with an average methane loss rate of 8.8% of production leaked at the wellhead.[98] In the Appalachian Basin, researchers reported that marginal well sites in Pennsylvania and West Virginia have enormously varied methane loss rates, ranging anywhere from 0.35% to 91% of their production.[99] For the very low production category of 0-1 BOE/day wells, which contribute just 0.2% and 0.4% of national oil and gas production, respectively, researchers in the Appalachian Basin estimated that wellhead methane emissions account for 11% of the production-related methane emissions in the EPA's inventory.[100] The same research observed that many marginal wells

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[94] Robertson et al., *supra* note 67.
[95] Cusworth et al., *Intermittency of Large Methane Emitters in the Permian Basin*, Envtl. Sci. Tech. Letters __ (2021), https://pubs.acs.org/doi/abs/10.1021/acs.estlett.1c00173.
[96] *See* Attachment A (PermianMAP November 2021 Flyover Results).
[97] Omara et al., *Methane emissions from US low production oil and natural gas well sites*, 13 Nat. Comms. 2085 (2022), https://www.nature.com/articles/s41467-022-29709-3.
[98] 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.
[99] Omara et al., *Methane Emissions from Conventional and Unconventional Natural Gas Production Sites in the Marcellus Shale Basin*, 50 Env. Sci. Tech. 2099 (2016), https://pubs.acs.org/doi/10.1021/acs.est.5b05503.
[100] Deighton et al., *Measurements Show that Marginal Wells are a Disproportionate Source of Methane Relative to Production*, 70 J. Air & Waste Mgmt. Assn. 1030 (2020), https://doi.org/10.1080/10962247.2020.1808115.

emit as much or more gas than they reported producing—in a region where natural gas is the primary product operators are aiming to sell.

The scientific understanding of oil and gas methane emissions has expanded greatly over the last decade and can inform improved reporting requirements and effective regulations for reducing emissions, especially fugitive monitoring programs. The science shows that due to the skewed distribution of emission rates and the intermittency of some large emission events, emission factors that do not account for this using statistical methods or are not operationally verified with large-scale, frequent measurement efforts will greatly underestimate total emissions. These studies highlight the importance of updating subpart W reporting methodologies to bring reported and estimated emissions into better alignment with observed emissions.

D. Reporting in Cases of Ownership Transfer

We generally support EPA's proposed revisions for reporting in cases of ownership transfer applicable to facilities in Onshore Petroleum and Natural Gas Production; Onshore Petroleum and Natural Gas Gathering and Boosting; Natural Gas Distribution; and Onshore Natural Gas Transmission Pipeline. We respectfully encourage EPA to strengthen its proposed approach by incorporating the recommendations described below to ensure ownership transfers do not strategically occur to cause emissions to become unreported, and when that will occur incidentally, that it is documented and disclosed. Ownership transfer is common in the oil and gas sector due to market volatility and other factors. In some circumstances, these transfers may be motivated in part by forthcoming regulations, corporate environmental commitments, and the methane waste charge recently enacted by Congress. Reporting in cases of ownership transfer should therefore account for these considerations and should not incentivize strategic transfers motivated by avoidance of otherwise applicable regulations, disclosure requirements, or the waste charge.

In recent years, stakeholders have grown increasingly concerned that oil and gas mergers and acquisitions may undermine emissions reduction efforts. If assets move from industry leaders in reducing emissions to companies without clear commitments and strong practices, emissions could increase and transparency could decrease, regardless of why the transactions take place. Traditional oil and gas dealmaking – blind to the climate implications of asset transfer – may not be compatible with a net zero world that demands sustained and proactive climate stewardship. Given the potential ramifications of oil and gas dealmaking, the "transferred emissions problem" has become increasingly important, especially as demand for decarbonization incentivizes companies to sell high-emitting assets. However, existing analysis has not captured the real scope of this problem, with sparse information on where upstream assets are moving and how asset transfers may impact climate outcomes.

A recent report by EDF analyzes global upstream oil and gas merger and acquisition data from 2017 through 2021, including specific high-risk transactions and the climate implications of oil and gas asset sales.[101] It finds that:

- **A significant amount of upstream oil & gas dealmaking has taken place in recent years**. Deal value in 2021 totaled $192 billion, exceeding annual deal value in 2015, 2016,

[101] EDF, *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/.

2018, and 2020. Additionally, the aggregate number of deals in 2021 rose to 498, surpassing 2015, 2016, and 2020.

- **Assets are flowing from public to private markets at a significant rate**. Over the last five years, the number of public-to-private transfers exceeded the number of private-to-public transfers by 64%. In each year during this period, public-to-private transfers comprised the largest share of deals.
- **Assets are increasingly moving away from companies with environmental commitments**.[102] In 2018, deals that moved assets away from companies with environmental commitments accounted for only 10% of transactions. By 2021, these deals accounted for 15% of transactions. During this same period from 2018 through 2021, more than twice as many deals moved assets away from operators with net zero commitments than the reverse.
- **Stewardship risk in upstream oil and gas appears to be rising**. The movement of upstream oil and gas facilities to private markets with traditionally less transparency and to companies with reduced environmental commitments suggests that a growing number of assets are at risk of weak climate stewardship.

EPA has a unique opportunity to understand how these transfers affect emissions reporting and can take concrete steps in this rulemaking that minimize the risk of emissions going unreported due to asset transfers. We welcome EPA's proposed changes to clarify reporting in cases of ownership transfer, which we briefly summarize below, followed by our recommended improvements.

EPA's proposed changes cover four scenarios of ownership transfer:

1) When the entire facility is sold to a single purchaser and the purchaser does not already report to the GHGRP in that industry segment, then the purchaser would be responsible for submitting the facility's annual report for the entire reporting year in which the acquisition occurred and would include any previously owned applicable emission sources in the same geographic area as part of the purchased facility beginning with the reporting year in which the acquisition occurred.
2) When the entire facility is sold to a single purchaser and the purchaser already reports to the GHGRP in that industry segment (and basin or state, as applicable), then the purchaser would merge the acquired facility with their existing facility for purposes of reporting under the GHGRP.
3) When the selling owner or operator retains some of the emission sources and sells the other emission sources of a facility to one or more purchasers, then the seller would continue to report for the retained emission sources unless and until that facility meets one of the criteria in 40 C.F.R. § 98.2(i) and complies with those provisions.
4) When the seller does not retain any of the emission sources and sells all of the facility's emission sources to more than one purchaser, then the seller would notify the EPA within 90 days of the transaction and the purchasers would either begin reporting their acquired

[102] Corporate commitments as of Q1 2022 were applied retroactively to transactions over the last five years. For example, if a company had a net zero commitment as of Q1 2022, it would be listed as a net zero buyer or seller in a 2017 transaction, even if it did not have a net zero pledge in 2017.

applicable emission sources as a new facility or add the acquired applicable emission sources to their existing facility.

We are most concerned with the application of scenarios 3 and 4. The proposed changes, and EPA's prior interpretation of reporting requirements in cases of ownership transfer,[103] are ambiguous in situations where the transaction causes the facility to be divided such that portions fall below the reporting threshold and are not merged into existing facilities. These types of transactions are the most concerning because it is likely to lead to unreported emissions and could result in gaming of otherwise applicable requirements.

We recommend EPA clarify that when a transaction causes a facility to become split between multiple owners such that each portion falls below the reporting threshold, the seller must continue reporting until the conditions in 40 C.F.R. § 98.2(i) are met. Alternatively, or in situations where the seller will cease to exist, the purchasers should continue reporting for three to five years, as specified in 40 C.F.R. § 98.2(i)(1)-(2). We also urge EPA to clarify that 40 C.F.R. § 98.2(i)(3) only applies when the operations entirely cease to operate, not when they cease to be operated by the seller but continue to operate. Finally, EPA should require owners and operators to notify EPA when transactions occur and should track these transactions. We believe new regulatory requirements, corporate environmental commitments, and the methane waste charge result in at least some strategic asset transfers to avoid otherwise applicable requirements, and that EPA should track and publicly disclose these transactions.

E. Large Release Events

We support EPA's proposal to include a new category of reported emissions from large release events (250 mtCO2e per event (10 mtCH4) or approximately 500,000 scf of pipeline quality natural gas), but we urge EPA to set a lower threshold that captures more of these events. If EPA does not lower the threshold, we encourage EPA to account for emissions from large events missed by the proposed threshold and methodology through other aspects of the reporting program, such as through statistical incorporation into the leaker emission factors. Adoption of our proposed subpart W updates to comply with the MERP directive (described above) would also cure this problem.

The emission events that would be captured by EPA's proposed threshold are only the most catastrophic, sometimes releasing more greenhouse gas emissions than entire European countries–like the XTO well blowout in Ohio (60,000 tons of methane at a rate of 100 million scf per day)[104] and the Aliso Canyon leak (109,000 tons of methane).[105] While it is critical that such catastrophic events are reported, abnormal process conditions and equipment failures commonly lead to large emissions that fall below this threshold. These types of events, many of which will fall below EPA's proposed threshold, significantly contribute to the source category's total emissions–by our estimate, representing 63% of the total in the production

[103] EPA, *Frequently Asked Questions*, https://ccdsupport.com/confluence/pages/viewpage.action?pageId=198705183.
[104] Carlos Anchondo, *Exxon Well Blowout Caused 'Extreme' Methane Leak — Study*, E&E News (Dec. 17, 2019), https://www.eenews.net/articles/exxon-well-blowout-caused-extreme-methane-leak-study/; Sudhanshu et al., *Satellite Observations Reveal Extreme Methane Leakage from a Natural Gas Well Blowout*, 116 PNAS 26,376-81 (Dec. 16, 2019), https://www.pnas.org/doi/10.1073/pnas.1908712116.
[105] California Air Resources Board, *Aliso Canyon Natural Gas Leak*, https://ww2.arb.ca.gov/our-work/programs/aliso-canyon-natural-gas-leak#:~:text=A%20complete%20calculation%20of%20the,109%2C000%20metric%20tonnes%20of%20methane.

segment alone.[106] The existing reporting requirements do not account for super-emitters and abnormal process emissions at all, which is the primary cause of the difference between our estimates and EPA's. For reporting to be accurate and serve as the basis for accurate emissions estimates, such events must be addressed through the reporting estimation methodologies.

EPA should lower the reporting threshold for this category to encompass all leaks with a detected emission rate greater than 10kg/hr CH_4 discovered through a fugitive monitoring survey. An emission rate of this magnitude would exceed EPA's proposed large release event threshold of 10 $mtCH_4$ if it lasted for approximately 42 days. Under existing and proposed EPA regulatory standards, fugitive monitoring occurs at most bi-monthly (six times per year), so it is entirely possible that leaks of 10kg/hr or greater would go undetected for this length of time and exceed the threshold already proposed by EPA. However, under the existing threshold, these events would often go unaccounted for because operators could simply assume a detected large emission event had not been emitting for very long and choose to not report it as a large release event. Requiring leaks with detected emission rates greater than 10kg/hr CH_4 to be reported will help to ensure that reported emissions reflect what is observed in the field, and can inform the development of EPA's estimates, helping to reduce the large discrepancy with the majority of other independent scientific estimates.

Operators that discover these events will usually have done so as part of a fugitive monitoring survey or due to a notification from a third-party. They are therefore likely to investigate the source and fix the underlying problem, whether voluntarily or for regulatory compliance. Operators that do so should be able to subtract from their reported emissions the emission-factor or engineering calculation estimate associated with the equipment or component that caused the large leak, for the period in which the leak is estimated to have occurred (the duration of leak should be estimated either through use of operational data, or where none is available, the leak should be assumed to have existed since the last LDAR survey). This will ensure emissions are not double counted. For example, in the case of a large emission event attributed to an unlit associated gas flare, an operator could exclude reporting the event if they adjusted the associated gas flaring and venting data to account for the event's anomalous venting.

F. Alignment with OOOOb & OOOOc

We support EPA's efforts to align subpart W with forthcoming regulatory requirements and in this section we provide recommendations for further alignment. A significant portion of subpart W reporting facilities and emission sources will become subject to leak detection and repair (LDAR) requirements under OOOOb or an applicable approved state plan or applicable Federal plan developed under OOOOc in the coming years.[107] We therefore support EPA's proposal to require these facilities to report data gathered through leak monitoring surveys, and the option to do so voluntarily for facilities or portions of facilities not subject to regulatory monitoring requirements. Because these facilities and sources will already be required to monitor for LDAR compliance, reporting data gathered through those surveys to subpart W poses very little additional burden. EPA should additionally require for larger leaks that duration be estimated, either

[106] *See* Figure 2 above.
[107] 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. at 63,110 (proposed Nov. 15, 2021).

through use of operational data, or where none is available, the leak should be assumed to have existed since the last LDAR survey.

We also support EPA's proposal to expand the current reporting requirement in 40 C.F.R. § 98.236(q)(1)(iii) to require reporters to indicate if any of the surveys of well sites or compressor stations used in calculating emissions under 40 C.F.R. § 98.233(q) were conducted to comply with the fugitive emissions standards in OOOOb or an applicable approved state plan or applicable Federal plan. We believe this information will be useful to understand the amount of leak monitoring that is occurring voluntarily versus for compliance, and for understanding the effectiveness of LDAR regulations.

To align subpart W reporting with the alternative screening LDAR approach proposed for OOOOb and OOOOc, we suggest that EPA include as a separate category of reported emissions those detected through screening. This could be done by adopting our recommendations for "large release events" described above. If follow up OGI surveys can pinpoint the emission source, then the emissions should be attributed to that source. But in some cases emissions may not be found on follow up; those should nonetheless be reported in a separate category. EPA should revisit this topic when considering how to meet the MERP directive as well because many of the advanced technologies that may be used for compliance with OOOOb and OOOOc are capable of measurement and will detect emissions that far exceed the default leaker factors. For example, applying the default leaker factor to emissions detected by an aerial survey would greatly underestimate the magnitude of the leak. We recommend that EPA align reporting requirements with the finalized OOOOb and OOOOc advanced screening standards, and take care to ensure reporting does not disincentivize the adoption of these technologies.

G. Pneumatic Devices

EPA has proposed a number of updates to the estimation of emissions from pneumatic devices that we generally support. These categories of updates include:

- Updates to population emission factors for pneumatic devices in the production and gathering and boosting segments;
- Updates to population emission factors for pneumatic devices in the transmission and storage segments;
- Requiring facilities in natural gas processing to report emissions from pneumatics using the same emission factors as transmission and storage;
- An alternative methodology for intermittent devices in the production and gathering and boosting segments to allow for different emission factors for functioning and malfunctioning devices;
- Clarifying operational hours for pneumatics as "in service" rather than "in operation" to correct misinterpretations; and
- Updates for pneumatic pumps.

1. *Updates to Emission Factors in the Production and Gathering and Boosting Segments*

EPA's proposed updated emissions factors based on more recent measurement data are an improvement from existing factors, but may not fully account for the duration of malfunctions due to the short measurement periods in the underlying studies. EPA's updated factors are much higher for low-bleed devices, slightly lower for intermittent-bleed devices, and fairly comparable for high-bleed devices (see comparison tables below). Because of our concerns about the short measurement periods used to support the proposed emission factors, we recommend that EPA instead adopt emission factors based on the DOE G&B Study, which we believe more accurately represents emissions from pneumatic devices.

In order to create new emission factors for the production and gathering and boosting segments, EPA averages data from six studies (Table 2-9): GRI/EPA (1996), Allen et al. (2015), Prasino Group (2013), DOE G&B Study (2019) (also known as Zimmerle et al./Luck et al.), and API Field Study (2019) (also known as Tupper et al.). EPA also proposes alternative emission factors, which are displayed in parentheses in the table below. EPA notes that they calculated alternative emissions factors for production and gathering and boosting due to "uncertainty related to short measurement periods during the Allen et al. (2015) study and potential bias of devices with zero emissions for intermittent bleed devices and with the representativeness of Prasino Group (2013a) measurements for the US." We agree with EPA's assessment of the short measurement period's bias towards low emissions; a fifteen minute measurement would fail to accurately assess emissions from an actuation, and thus underestimate emissions from the device.

However, these concerns about short measurement periods also apply to the API Field Study–this study used a sample period of approximately fifteen minutes. In contrast, the DOE G&B Study conducted measurements that lasted approximately three days. To our knowledge, this is the only study that has measured emissions for this length of time. This is important because a fifteen minute measurement period can result in a significant measurement error.[108] Luck et al. analyzed the pneumatic controller data collected as part of the DOE G&B Study. It conducted a Monte Carlo analysis to determine how large the measurement error would be if one were to observe the pneumatic controller for fifteen minutes rather than three days. It determined that: "For the mix of [pneumatic controllers] measured here, the average expected absolute error of a 15 min measurement is 49% [31−71%]. If the measurement duration is extended to 24 h, the expected absolute measurement error is reduced to 20% [11−31%]."[109] Therefore, we do not recommend that EPA base emission factors on studies that used a fifteen minute (or less) measurement period. The figure below shows the simulated measurement error from each pneumatic controller in Luck's analysis; the mean error for all 61 controllers is shown as the overlaid red line.

[108] Benjamin Luck et al., *Multiday Measurements of Pneumatic Controller Emissions Reveal the Frequency of Abnormal Emissions Behavior at Natural Gas Gathering Stations*, 52 Env. Sci. Technol. Letters 348 (2019), https://pubs.acs.org/doi/10.1021/acs.estlett.9b00158 (analyzing pneumatic data collected in DOE G&B study).
[109] *Id.*

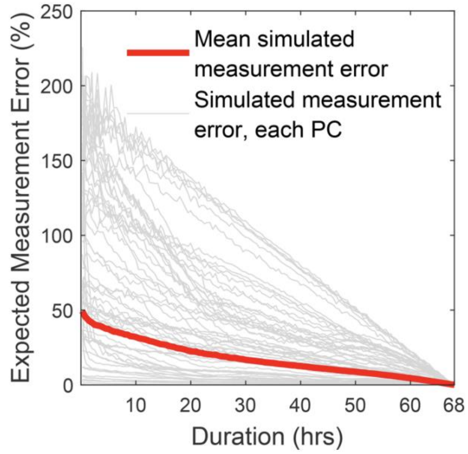

Figure 3: Luck et al. Simulated Measurement Error

Due to this potential for error, we recommend that EPA update emission factors based on the results of the DOE G&B Study, rather than averaging emission factors from studies of varying qualities. While the DOE G&B Study focused on gathering and boosting stations, we believe it is appropriate to apply these emission factors to the production segment as well. EPA has historically used the pneumatic emission factors from the production segment for gathering and boosting as well, and we believe it is appropriate to continue doing so here.

Pneumatic Device Emission Factors for Production and G&B

(scfh)	CATF/EDF Proposed Updated Emission Factor	EPA Proposed Updated Emission Factor	Old Subpart W Emission Factor
Low Bleed	7.6	6.8 **(or 7.6)**	1.39
Intermittent Bleed	11.1	8.8 **(or 10.3)**	13.5
High Bleed	19.3	21.2 **(or 23.7)**	37.3

We note that the API Field Measurement Study (Tupper et al. 2019), which was presented at the 2019 EPA Stakeholder Workshop on Oil and Gas, has not been peer-reviewed and the full dataset is not publicly available. In contrast, the DOE G&B Study includes peer-reviewed articles (including Zimmerle et al. 2019, Luck et al. 2019, and Vaughn et al. 2021) for which all data is publicly available.[110] It is impossible for stakeholders to critique the methodology or conclusions of the API Field Measurement Study without access to transparent and granular data.

2. *Updates to Emission Factors in the Transmission and Storage Segments*

To calculate emission factors for low and high bleed pneumatic devices, EPA relies on an analysis of the aggregate Zimmerle et al. (2015) continuous bleed emission factor along with subpart W data.[111] EPA then

[110] Colorado State University, *Data - Characterization of Methane Emissions from Gathering Compressor Stations*, https://mountainscholar.org/handle/10217/195489.
[111] *See* Greenhouse Gas Reporting Rule: Technical Support for Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule; Proposed Rule – Petroleum and Natural Gas Systems,

back-calculates an effective high bleed emission factor based on the prevalence of high and low bleed devices as reported in subpart W and an assumed low bleed device emission rate. For intermittent devices, EPA used the average intermittent bleed factor from the GRI/EPA study (1996).

Pneumatic Device Emission Factors for Transmission, Storage, and Processing

(scfh)	EPA Proposed Updated Emission Factor	Old Subpart W Emission Factor
Low Bleed	6.8	1.37
Intermittent Bleed	2.3	2.35
High Bleed	32.4	18.2

We support EPA's proposed update to pneumatic device emission factors in the transmission and storage industry segments. However, we encourage EPA to seek measurement data for pneumatic devices in these industry segments. EPA notes that "if these intermittent bleed devices are subject to malfunction emissions, the intermittent bleed pneumatic device emission factor used in subpart W for the transmission and storage industry segments would not include excess emissions caused by worn or malfunctioning devices."[112] We are concerned about potential device malfunctions and encourage EPA to pursue measurement data on pneumatic devices, particularly intermittent devices, in these industry segments.

3. *Apply Emission Factors from the Transmission and Storage Segments to the Gas Processing Segments*

EPA is also proposing to require facilities in onshore natural gas processing to report emissions from pneumatics using the same emissions factors as transmission and storage. As EPA notes, natural gas driven controllers are far less common in the processing segment. However, in the interest of completeness, it is appropriate for EPA to include this emission source category so that operators are required to report these emissions if and when this equipment is used in this segment. We support EPA's proposed updated emissions factors for the gas processing segment.

4. *Alternative Methodology: Differentiating Functioning and Malfunctioning Intermittent Bleed Pneumatic Devices*

EPA proposes an alternate methodology for remaining intermittent bleed pneumatic devices based on the results of inspections. This methodology employs emission factors from a 2019 API Field Measurement Study, which as described above, we have not been able to fully evaluate. We have significant concerns about EPA's proposed alternative methodology for intermittent bleed pneumatic devices based on the results of inspections. For intermittent bleed pneumatic devices, EPA has proposed an alternative methodology that requires monitoring surveys and applies a bifurcated emissions factor approach. Operators would survey their pneumatic devices and calculate emissions using Tupper et al.'s emissions factors for properly functioning and malfunctioning devices.

Table 2-10, https://www.regulations.gov/document/EPA-HQ-OAR-2019-0424-0120 [hereinafter "Subpart W TSD"].

[112] Subpart W TSD at p. 19.

While such an approach could lead to more granular data on whether controllers are malfunctioning or not, we are concerned that OGI surveys may not accurately characterize emissions from malfunctioning controllers. EPA believes this approach could incentivize operators to look at their controllers during the OGI survey (as should be required), because they would be able to use a lower emission factor if the controller is determined to be functioning properly. EPA also believes it would help the agency to track emissions increases or decreases tied to malfunctions. However, as we describe below, there are serious flaws with this bifurcated approach. Due to these flaws, we recommend that EPA not finalize this "leaker" approach for intermittent bleed pneumatic controllers.

As EPA notes, Tupper et al. found that approximately 38% of intermittent controllers (99 out of 263) were malfunctioning. The Tupper study made most of its measurements at well production and gathering and boosting sites using a GHD recording high volume sampler with about 0.5 Hz recording, with measurements lasting approximately 15 minutes each. As discussed above, the DOE G&B study found that 15 minutes is not sufficient time to determine whether a controller is malfunctioning. The DOE study, using observation times much longer than 15 minutes, found a malfunction rate of 63% for intermittent controllers. Therefore, the results in Tupper are an underestimate of the actual percent of intermittent controllers that are likely to be malfunctioning. Using a less sensitive monitoring technology (OGI) over an even shorter time period than 15 minutes, will result in identifying an even lower number of malfunctioning controllers.

Luck et al. extensively measured emissions from 72 controllers at 16 natural gas compressor stations, recording consumption of gas by the controllers for multi-day periods. They found that a very large portion of controllers were abnormally operating, leading to emissions substantially higher than emissions from normal operating controllers. Of the overall pool of controllers, 42% were operating abnormally. Of the 40 intermittent controllers they studied, 25 (63%) were operating abnormally.[113]

While the total number of controllers measured is lower in Luck than in Tupper, the Luck study measured each controller for approximately three days (as opposed to fifteen minutes in Tupper). In many cases, the controller appeared to be operating properly in the first fifteen minutes, but later on in the three day period, a malfunction occurred. The Luck study used four criteria for determining whether an intermittent bleed controller was malfunctioning:

1. <u>Continuous Emissions</u>: Emissions recording of an intermittent vent PC that does not show control actuations and emits gas continuously
2. <u>Extended Ramp</u>: PC shows an emission ramp longer than three minutes in duration leading up to an actuation event
3. <u>Does Not Return to Zero</u>: PC shows control actuations but emission rates do not return to zero between actuation events
4. <u>Irregular Behavior</u>: Intermittent vent PC shows some combination of the previous three behaviors or generally irregular emissions patterns.

If the emissions trace for an intermittent vent device met any of these criteria, the controller was identified as abnormally operating. Luck then conducted a Monte Carlo analysis to determine how large the

[113] Benjamin Luck et al., *supra* note 108.

measurement error would be if one were to observe the pneumatic controller for fifteen minutes rather than three days.[114] This Monte Carlo analysis included all the controllers in their sample, both continuous and intermittent bleed, and it looked at the actual emissions rate measured rather than simply the determination of functioning versus malfunctioning.

In order to separate out results for intermittent controllers and to distinguish between functioning and malfunctioning controllers, Clean Air Task Force did an independent review of the supporting information published alongside the Luck study. The review found that 10 of the 25 malfunctioning intermittent controllers were malfunctioning from the beginning of measurement, and the other 25 were determined to be malfunctioning based on observations after the first hour of measurement.[115] This means that if Luck had only taken measurements for 15 minutes, as Tupper did, it would have found only 10 out of 40 intermittent bleed controllers malfunctioning, a 25% malfunction rate.

In 2018, the Colorado Pneumatic Controller Task Force (PCTF) conducted a field study examining the operation of these devices in Colorado's non-attainment area (NAA). The findings are described in a 2020 report to the Colorado Air Quality Control Commission.[116] One of the goals of this study was to document malfunction rates and causes for controllers that would be found using the state's "find and fix" program. In this program, operators are required to observe pneumatic controllers during their already required instrument-based leak detection and repair surveys, and fix any controller found to be malfunctioning. The study found that 5.6% of the inspected intermittent controllers were operating improperly, far lower than the malfunction rate in either Tupper or Luck.[117] We believe this divergence is likely attributable to short observation times used during OGI inspections.

Stovern et al. also studied pneumatic controllers in the Denver-Julesberg basin in 2018.[118] This study directly observed that 11.3% of the intermittent controllers were emitting continuously, due to a maintenance issue. However, the study notes that due to methodological issues, this 11.3% figure is probably an underestimate of the actual rate of malfunction among the intermittent controllers they inspected. They estimate that the true rate of malfunction in their sample was 11.6 – 13.6%, again far lower than the malfunction rate in either Tupper or Luck.[119] The Stovern study was also based on OGI camera inspections of pneumatic controllers, and was designed to be a "snapshot in time" to determine whether an intermittent controller was malfunctioning.

The PCTF report and the Stovern study suggest that the range in the percent of intermittent controllers likely to be found malfunctioning using a snapshot OGI survey is well below the average presented in the

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[114] *Id.* at Figure 2.

[115] Benjamin Luck et al., *Methane emissions from gathering and boosting compressor stations in the U.S. Supporting volume 1: Multi-day measurements of pneumatic controller emissions, SI-7 Meter Recording*, https://mountainscholar.org/handle/10217/194543.

[116] Pneumatic Controller Task Force Report to the Air Quality Control Commission, Colo. Air Pollution Control Div., 12 (June 1, 2020), https://drive.google.com/file/d/1JStgs0SD2NvZIht1Ti8QQnJAmUZxKgsn/view.

[117] *Id.*

[118] Michael Stovern et al., *Understanding Oil and Gas Pneumatic Controllers in Denver-Julesburg Basin Using Optical Gas Imaging*, 70 J. of the Air & Waste Management Assoc., 9 (2020), https://doi.org/10.1080/10962247.2020.1735576.

[119] *Id.*

Tupper paper, which EPA seeks to rely on. And in turn, the Tupper estimate for the percent of intermittent bleed controllers that are malfunctioning is lower than the actual malfunction rate found in the longer survey period used in the Luck study. Thus, if EPA were to adopt this approach, it would result in a significant underestimate of emissions from intermittent bleed pneumatic controllers. We therefore recommend that EPA does not adopt this alternative approach.

Finally, we note that the waste charge contained in MERP (discussed above), may incentivize underreporting in order to stay below the charge thresholds. This cost could lead some operators to choose the proposed alternative approach in order to minimize reported emissions from malfunctioning controllers in a manner that is likely inconsistent with actual observed emissions. This, in conjunction with the short observation periods of OGI inspections, should be considered by EPA, and we believe weigh against finalizing the alternative approach.

5. *Clarify Operational Hours for Pneumatics as "In Service" Rather Than "In Operation"*

We support EPA's proposal to revise the definition of variable "Tt" in Equation W-1 and the corresponding reporting requirement in 40 C.F.R. § 98.236(b)(2) to use the term "in service" (i.e., supplied with natural gas) rather than "operational" or "in operation." This clarification is important because it would prohibit operators from reporting their controllers as operating for the brief moments that they emit gas. Bloomberg News reported that several companies have reported their controllers as in operation for less than ten minutes per day, leading to significant underestimates of emissions.[120] By updating this definition to "in service," EPA can close this reporting loophole and more accurately quantify emissions.

6. *Updates for Pneumatic Pumps*

We support EPA's proposal to revise the definition of variable "T" in Equation W-2 in 40 C.F.R. § 98.233(c)(1) for natural gas driven pneumatic pumps to use the term "in service (i.e., supplied with natural gas)." We also support the proposal to use that same term in the corresponding reporting requirement in proposed 40 C.F.R. § 98.236(c)(4). Given that the population emissions factor for natural gas driven pneumatic pumps reflects average emissions over the period the pump is operating, this revision will ensure that reporters accurately quantify emissions from this component.

7. *Other Clarifying Changes*

We also support EPA's proposal to include flared emissions from natural gas driven pneumatic pumps in the calculation of total flare and flare stack emissions. And we support the proposal to include emissions from natural gas driven pneumatic pumps that are routed to a combustion unit in the calculation of total emissions from the combustion unit. These changes will help ensure flared and combusted emissions are accurately reported. We suggest that EPA extend this proposal to include flared and combusted emissions from all pneumatic devices in the calculation of total flare and flare stack emissions. Future regulatory requirements could make this practice more common.

[120] Zachary Midler, *Methane 'Loophole' Shows Risk of Gaming New US Climate Bill*, Bloomberg News, Aug. 10, 2022, https://www.bloomberg.com/news/articles/2022-08-10/methane-loophole-shows-risk-of-gaming-new-us-climate-bill .

We further support EPA's proposal to expand the current requirement to report the total count of natural gas driven pneumatic pumps to three separate counts: the count of natural gas driven pumps that vent to the atmosphere (i.e., uncontrolled); the number of natural gas driven pneumatic pumps that are routed to a flare, combustion, or vapor recovery (i.e., controlled); and the total number of natural gas driven pneumatic pumps at the facility. This information would help to better characterize emissions from this source, and provide much-needed data on how many natural gas driven pneumatic pumps are controlled. We suggest that EPA implement a similar reporting requirement for natural gas driven pneumatic devices. There is limited data on how many pneumatic controllers route to process or combustion device; implementing this reporting requirement more broadly would gather better data on controlled and uncontrolled pneumatic devices.

H. Equipment Leak Survey Method and Leaker Emission Factors

We support EPA's proposal to amend the leaker emission factors in Table W–1E for production and gathering and boosting facilities to include separate emission factors for leakers detected with OGI. EPA's proposed emission factors were developed by combining the data from Zimmerle et al. (2020) and Pacsi et al. (2019), and represent an improvement from the outdated factors currently being used. We also agree that using the same leaker emission factor for components detected with OGI and Method 21 with a leak definition of 10,000 ppm, as is currently done in subpart W, likely understates the emissions from leakers detected with OGI. We therefore support a requirement to use OGI leaker emission factors to quantify the emissions from the leaks identified using other monitoring methods.

We also support EPA's proposal to apply the ''OGI enhancement'' factor identified from measurement study data in the onshore production and gathering and boosting industry segments to the leaker emission factors for the other subpart W industry segments as a means to estimate an OGI emission factor set. EPA's rationales for proposing these factors for the production segment apply equally to other segments, and EPA's proposal to apply the enhancement factor is therefore reasonable and will lead to more accurate estimates.

EDF strongly supports the alternative proposed option that would allow reporters to quantify emissions from equipment leak components by performing direct measurement of equipment leaks and calculating emissions using those measurement results.[121] It is important, as EPA has recognized, that reporters using this option quantify and report all leaks identified during a "complete leak detection survey." Otherwise, reporters could use leaker emission factors for some leaks and quantify other leaks identified during the same leak detection survey, leading to selective and non-representative reporting. However, it is not necessary for operators to measure all leaks at an onshore production facility as proposed. Instead they should measure a statistically robust subset of representative leaks, following protocols set forth by EPA. If operators use this approach, they must measure all leaks at surveyed sites to avoid selective measurements. Some leaks will be too large to measure with component-level approaches, but reporters should first try to measure with other approaches like site-level measurements, or as a last resort,estimate

[121] 86 Fed. Reg. at 36,976-77.

with engineering calculations. Operators should report the detailed data to EPA, and EPA would then analyze the data to improve emission factors and publicly release an anonymized, aggregated dataset.

I. Equipment Leaks by Population Count and Population Emission Factors

Subpart W also allows reporters to follow equipment leaks by population count method which uses the count of equipment components, subpart W emission factors, and operating time to estimate emissions from equipment leaks.[122] Under this method, the count of equipment components may be determined by counting each component individually for each facility (Component Count Method 2) or the count of equipment components may be estimated using the count of major equipment and subpart W default average component counts for major equipment (Component Count Method 1). EPA's review of reported data shows that the vast majority of reporters use Component Count Method 1 to estimate component counts.[123]

We strongly support EPA's proposal to include new population emission factors that are on a per major equipment basis rather than a per component basis. We believe that providing emission factors on a major equipment basis instead of by component would reduce reporter error by eliminating the step of estimating the number of components, and that use of major equipment factors should be required whenever it is possible. We also believe this would reduce reporter burden and reduce the number of errors in the calculation of emissions, leading to better overall emissions estimates. Finally, we conditionally support EPA's proposal to provide additional equipment emission factors based on the Pacsi and Zimmerle studies for more pieces of equipment than are currently included in subpart W. We believe this is a near-term improvement, but we note some deficiencies with relying solely on these two studies below.

While proposed emission factors derived from the Pacsi and Zimmerle studies represent an improvement from the existing and outdated emission factors, they still do not adequately account for intermittent, large emission events. For the emission factors to lead to accurate estimates, they must account for the infrequent, large emission events that characterize oil and gas emissions. We recommend that EPA consider future revisions to emissions factors that better represent the heavy-tailed emission distribution discussed in detail above.

Rutherford et al. (2021) provides an example for how large emission events can be accounted for using a bottom-up emission factor approach.[124] The Rutherford model accounts for these events when developing emission factors using a bootstrap resampling statistical approach. EPA cites this study alongside Zimmerle et al., 2020 and Pacsi et al., 2019, as "provid[ing] the necessary data to develop and compare study-estimated population emission factors as well as study-estimated default component counts per major equipment to those in subpart W."[125] But then EPA relies only on the Zimmerle and Pacsi studies for its proposed emission factors even though the Rutherford study is based on greater measurement data and robustly accounts for infrequent, large emission events. We recommend that EPA account for large intermittent emission events when revising emission factors.

[122] *Id.* at 36,979.
[123] *Id.* at 36,980.
[124] Rutherford et al., *supra* note 59.
[125] Subpart W TSD at 46.

The Rutherford study and estimation tool undertakes two sequential extrapolations: first from the component to the equipment-level, and second from the equipment to the national or regional-level.[126] The approach utilized in the bottom-up estimation tool begins with a database of component-level direct emissions measurements (e.g., component-level emission factors). The authors generate component-level emission factor distributions from a literature review building on prior work and adding new publicly available quantified measurements. The resulting database includes around 3,700 measurements from six studies across a 12-fold component classification scheme. They then derive equipment-level emission factors through random resampling (i.e., bootstrapping, with replacement) from the component-level database according to component counts per equipment and fraction of components emitting. Some of the studies relied on by Rutherford et al. also calculate equipment-level emission factors, but these are not used as inputs. Instead, the authors take the combined component-level emission data, component counts, and fraction of components found to be leaking, and derive values different from the values calculated in the underlying studies. The authors then use these emission factors to construct a bottom-up inventory that largely aligns with the top-down literature and estimates.

The Rutherford estimation tool provides a useful example of how emission factors can be derived that reflect and align with top-down literature and observed emissions. For the default subpart W emission factors to provide useful estimates that give an accurate picture of actual observed emissions, it is critical they incorporate super-emitter events. If they do not, the reporting program could disincentivize operators from using advanced measurement technologies and reporting better data because doing so will lead to higher reported emissions than they would calculate using the existing and proposed emission factors.

Below we include a standardized comparison of EPA's proposed emission factors, based on the Pacsi and Zimmerle studies, and the emission factors from the Rutherford study (averaged marginal and non-marginal). As shown, the Rutherford emission factors are significantly higher because they account for large, intermittent emission events and align with actual observed emissions.

Natural Gas Sites

Equipment Type *not a direct equipment type comparison	**Rutherford EF - Average (scf/hr)**	**GHGRP EF (scf/hr)**
Wellhead	8.6	0.59
Separator	8.87	0.84
Meters/piping*	7.04	2.8
Compressor	14.61	10

[126] *See* Rutherford et al., *supra* note 59.

Dehydrator	6.78	3.1
Heater Treater*	6.52	0.12
Storage Vessel	Multiple EFs	0.85

Oil Sites

Equipment Type *not a direct equipment type comparison	**Rutherford EF (scf/hr)**	**GHGRP EF (scf/hr)**
Wellhead	3.91	0.59
Separator	4.17	0.43
Meters/piping*	7.04	2.5
Compressor	N/A	10
Dehydrator	N/A	3.1
Heater Treater*	2.87	0.35
Storage Vessel	Multiple EFs	0.56

J. Flared emission reporting

We support EPA's proposed additional reporting requirements for individual flare stack characteristics, which are necessary to better understand the relationships between flare taxonomy and operation. In addition to flare unit characteristics, we recommend adding reported data elements covering the maximum and minimum flow values of the flare itself. These data elements will help EPA understand whether emissions are coming from high- or low-pressure flares, and the overall purpose of an individual flare in relation to other equipment on the site.

The overall effectiveness of a flare relies on the flow falling within an optimal range. During helicopter-based OGI flights conducted from 2020-2021, EDF documented several flare stacks consistently burning with large amounts of incomplete combustion. We suspect that the incomplete combustion is a result of an air assist increasing gas flow beyond the flare stacks' optimal range. As more research organizations and companies independently conduct field observations, reporting of these characteristics would help enrich these observations and collectively help all stakeholders better understand possible causes of these emissions.

While the proposed restructuring will make how to report flared gas emissions more clear, and reporting flare stack characteristics will enrich flare unit level data, there are no proposed elements that will improve the underlying quality of how flare gas emissions are calculated. Without improvements on what reporters put into the inventory, the inventory will not capture the nature of flared gas emissions that has been documented through research.[127]

1. *Flare Combustion Efficiency*

The GHGRP currently allows operators to assume 98% combustion efficiency of converting natural gas CH4 into CO2 based on the findings of a technical report conducted in controlled settings. However, in-situ measurements of flares across multiple basins show an average of ~95% combustion efficiency, with an even lower average (91%) occurring for flares in the Permian Basin.[128] In 2020, all production-segment flare units in the Permian with emissions reported having at least 98% combustion efficiency. The universal application of this assumption by reporters is driving an underestimation of flared gas CH4 emissions, and is a contributing factor to the divergence between EPA estimates and top-down estimates based on empirical measurements.

We recommend that EPA lower the 98% combustion efficiency assumption to 95%, thereby aligning it with existing regulatory standards and the average multi-basin combustion efficiency observed in Plant et al. (2022).[129] That study is based on samples of more than 600 intercepts of flare combustion plumes, representing more than 300 distinct flares across the three basins responsible for over 80% of US flaring.[130] As flaring activity and performance may differ at the basin level, in the future we encourage EPA to consider segmenting the combustion efficiency assumption per basin according to in-situ measurements. We also recommend that EPA require Permian Basin facilities to report using the 91% efficiency observed in the Plant study. This study contains the most recent, comprehensive, and accurate data on flare efficiency in the Permian.

2. *Unlit Flares*

[127] Note also our recommendations that LNG Import/Export facilities continuously monitor flare and engine emissions, or at least use frequent stack testing rather than default emission factors. This is discussed in more detail in the LNG Related Processes section below.
[128] Genevieve Plant, et al., *Inefficient and Unlit Natural Gas Flares Both Emit Large Quantities of Methane*, 377 Science 6614 (2022), https://www.science.org/doi/10.1126/science.abq0385.
[129] *Id.*
[130] Id.

The rate of unlit flares is a prevalent issue across the oil and gas industry. 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.[131] According to GHGRP flare unit data for 2020, the average fraction of gas sent to an unlit flare for all flares located in the Permian was ~1%. While the observations from Lyon et al. (2021) are a measure of frequency and do not account for how much gas was released volumetrically, as a proxy the data shows there is a large divergence between reported and observed activity of unlit flares.[132]

Current and proposed reporting requirements and elements require reporters to determine the fraction of gas sent to an unlit flare using the best available engineering estimate and process knowledge. EPA's proposal to require reporting on whether or not a continuous pilot is used and how, generally, periods of unlit flares are determined is insufficient. There is no express requirement to monitor nor connect this activity data to the amount of gas produced during the unlit period. Additionally, it is unclear from the proposal how a reporter should specify if or how they monitor ignition of the flare that has an auto-igniter instead of continuous pilot, as it is still possible for auto-igniters to malfunction resulting in an unlit or poorly combusting flare. The lack of ignition monitoring requirements and reporters' reliance on engineering estimates is a likely cause of the gap between reported and observed flaring activity.

We urge EPA to consider methods for empirically monitoring flare ignition. Specifically, EPA should require reporters to use such methods alongside their production activity to report the temporal duration a flare was unlit, and how much gas was emitted during these durations. Many flares are already equipped with temperature transmitters that monitor the pilot light and can be incorporated into a site's SCADA system. By combining this activity data alongside the gas production data or a continuous flow measurement device attached to the flare, reporters can accurately measure the volume of gas sent to an unlit flare. EPA and stakeholders would then be able to use the categorical data on pilot light type to assess which configuration of flares operates with the least malfunctions and longest periods of uptime.

To incorporate the possibility of auto-igniters failing leading to an unlit flare, we ask EPA to expand reporting requirements. Specifically, EPA should require reporters to answer these questions: "If the flare has an auto-igniter, is the presence of the flame monitored during periods when the auto-igniter is activated and gas is routed to the flare?" and "If the flare has an auto-igniter and the flame is not monitored during active periods, how does the reporter verify that combustion is occurring?"

3. *Associated Gas Venting and Flaring*

EPA has also proposed several updates related to the estimation and reporting of associated gas venting and flaring. These updates include elements that would allow continuous flow measurement devices to be used for estimating flaring emissions. And, if such a device is present, operators would be required to use it to also estimate volume of gas vented.

In cases where a continuous flow measurement device is not present, operators are still allowed to use equation W-18 to estimate volume of vented and flared gas. And, to reduce confusion regarding the calculation of associated vented and flared gas, the proposal adds the word "only" to the definition of Vp,q

[131] Lyon et al., *Concurrent Variation*, *supra* note 68.
[132] *Id.*

and SGp,q in W-18. EPA notes that companies appear to have been misinterpreting the requirement, and reported the same value for "volume of associated gas sent to sales for each well in the sub-basin during time periods in which associated gas was vented or flared" and "total volume of gas sent to sales for the facility." In these cases, operators may be overestimating venting and flaring. It appears that equation W-18 assumes that operators are venting or flaring all of their gas during certain periods, and venting or flaring none of their gas during other periods. However, this equation does not account for the periods when the operator is venting or flaring a portion of the gas produced, but not all of the gas produced. We suspect that operators reported the same value for the gas volumes because some portion of that volume was vented or flared during the entire time period, but there was no way to specify this detail. Thus, we suggest EPA add a reporting option so that operators can report both the time periods in which venting and flaring was occurring, and the portion of the gas produced that was vented or flared.

While making this clarification would improve data quality for associated gas venting and flaring, ultimately requiring flow measurement devices for all sites would eliminate this confusion entirely. A direct measurement of gas sent to the flare unit would allow reporters to better estimate the associated gas vented from individual emission sources between the well and flare. In many cases, reporters would be able to subtract the volume of gas sent to a flare from the flow measurement device from the total amount of vented and flared associated gas (equation W-18) to calculate the total volume of associated gas venting. Incorporating requirements for measurement devices, such as continuous flow measurement devices for flare units or flare temperature sensors, would greatly improve the accuracy of estimates for many reported emission sources.

K. Compressors

In this section, we provide recommendations on compressors and engine reporting requirements, covering the following topics: compressor methane slip; crankcase venting; reciprocating compressors; dry seal centrifugal emission factors; and standby pressurized mode for centrifugal compressors.

1. *Compressor Methane Slip*

We generally support EPA's proposal to update the emission factors for uncombusted methane emissions (i.e., "methane slip") from compressors. The table below, taken from the subpart W TSD, shows how different emission factors have been used for different sizes and different types of engines. EPA relied on these emission factors to calculate percent methane slip for each engine type and data source.

Table 10-4. Emission Factor Comparison (kg CH_4/MMBtu)[a, b]

Source	Engines			Industrial Gas Turbine (IGT)
	2SLB	4SLB	4SRB	
Zimmerle *et al.* (2019)	NM	0.522	0.045	NM
AP-42	0.658	0.567	0.104	0.0039
U.S. GHG Inventory	0.576	0.576	0.576	0.0020
GHGRP-Subpart C	0.001	0.001	0.001	0.001

[a] NM = not measured.

[b] The values in this table were taken from Table 1 in Vaughn *et al.* (2021) and converted from lb/MMBtu to kg/MMBtu.

For example, the GHGI uses the same emission factor for big and small engines, both rich- and lean-burn. The GHGRP also uses the same emission factor for all sizes and types, but that factor is much smaller than the GHGI's. Two other sources, Zimmerle et al. (2019) and AP-42 use different factors for types. We believe that it is appropriate to use AP-42 emission factors for 2SLB engines, and Zimmerle emission factors for 4SLB and 4SRB engines for the reasons set forth below.

The use of different factors for rich burn versus lean burn engines is well supported and we agree with EPA's proposal. Vaughn et al. (2019) (part of the same DOE G&B Study as Zimmerle et al. (2019))[133] supports the use of different emission factors for 4SLB engines depending on the model and size of the engine. As seen in Figure 4, the mean methane slip measured from 4SLB engines was 1.15 lb/MMBtu (0.522 kg/MMBtu), while mean methane slip measured from 4SRB engines was much lower, at 0.10 lb/MMBtu (0.045 kg/MMBtu).

However, there is a clear stratification in emissions within 4SLB engines, with certain engine models clearly having higher average emissions than others. Because different models emitted more (or less) than the AP-42 emission factor, the authors suggest that the "characteristics of these engine families that give rise to this difference may warrant a further stratification of the 4SLB emission factor category when such data are available."[134] Figure 5 shows that 4SLB engines in the Caterpillar G3500 have average emissions 0.52 lb/MMBtu (0.24 kg/MMBtu) and a different model, the Caterpillar G3600 series have average emissions of 1.41 lb/MMBtu (0.64 kg/MMBtu). Based on the measurements in Vaughn et al. (2021), we support the further differentiation in emission factors for methane slip based on the engine model.

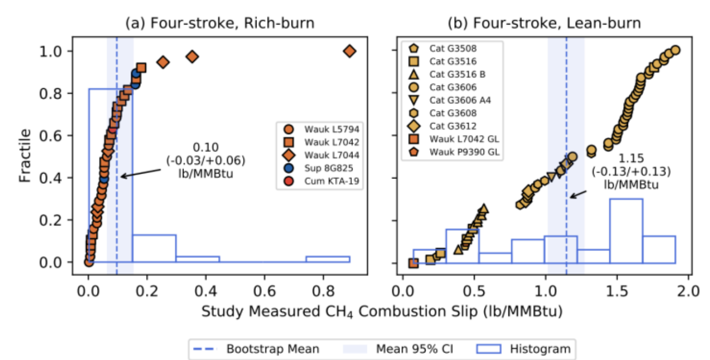

Figure S2-17: Combustion slip emission rates measured in this study using the in-stack tracer method for (a) four-stroke, rich-burn and (b) four-stroke, lean-burn engines. Mean combustion slip measured as found was (a) 0.10 (-0.03/+0.06) lb/MMBtu for 4SRB engines and (b) 1.15 (-0.13/+0.13) lb/MMBtu for 4SLB engines. Means and 95% confidence intervals about means for study data were obtained using bootstrap averaging.

Figure 4: Four-stroke, Rich-burn & Four-stroke, Lean-burn

[133] Vaughn et al. *Methane Exhaust Measurements at Gathering Compressor Stations in the United States*, *Environ. Sci. Technol.* (2021) https://pubs.acs.org/doi/10.1021/acs.est.0c05492?goto=supporting-info.
[134] Vaughn et al.,*Methane Exhaust Measurements at Gathering Compressor Stations in the United States*, *Supporting Volume 2: Compressor Engine Exhaust Measurements*, at 18, available at https://mountainscholar.org/bitstream/handle/10217/194542/DATAENEI_CharMethEmiss_SupportV2.pdf?sequence=1&isAllowed=y.

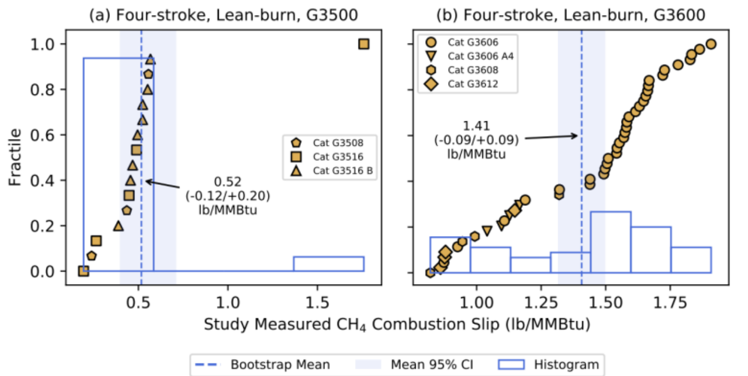

Figure S2-18: Combustion slip emission rates measured in this study using the in-stack tracer method for two 4SLB engine models. Combustion slip from engines in the (a) Caterpillar G3500 series were 0.52 (-0.12/+0.20) lb/MMBtu on average, or 59% lower than the AP-42 4SLB emission factor. Combustion slip from Caterpillar G3600 series engines was 1.41 (-0.09/+0.09) lb/MMBtu on average, or 13% higher than the AP-42 4SLB emission factor. Means and 95% confidence intervals about means for study data were obtained using bootstrap averaging.

Figure 5: Four-stroke, Lean-burn, G3500 & Four-stroke, Lean-Burn, G3600

2. *Engine Crank Cases*

Relatedly, we urge EPA to account for vented methane emissions from engine crank cases in the GHGRP. These emissions are not currently reported anywhere in the GHGRP. Data from Johnson et al. (2015) suggests that these emissions can be significant, finding that the average ratio of crankcase-to-exhaust emission was 14.4%.[135] The measurements are illustrated in the table below.

Table 5. Comparison of Combined Exhaust and Crankcase (CC) Methane Emissions Rates with Those Predicted by AP-42

site	CC/exhaust (%)	exhaust + CC (kg/h)	AP-42 (kg/h)	percent difference
1	8	13.3	13.4	−1
2	4	6.0	4.4	38
3	22	13.1	13.6	−4
4	12	3.4	5.8	−41
	13	3.6	5.8	−39
	7	4.5	5.8	−22

While this may be a difficult source to measure, given the significance of these total emissions we support EPA requiring operators to account for emissions from engine crank cases. This can be done either by requiring direct measurement, or by developing emission factors based on the available literature. EPA can rely on the published data from Johnson et al. (2015) to estimate the emission factor.[136] In addition, once

[135] Johnson et al., *Methane Emissions from Leak and Loss Audits of Natural Gas Compressor Stations and Storage Facilities*, 49 Env. Sci. Tech., 8132–8138 (2015), https://pubs.acs.org/doi/pdf/10.1021/es506163m.
[136] *Id.*

this source is quantified and tracked by the EPA, it will incentivize researchers to work to conduct additional measurements to improve the precision of these factors.

3. *Reciprocating Compressors*

Finally, we believe EPA's proposed methods for reporting emissions from reciprocating compressors are adequate as long as measurements are taken correctly and capture all locations where methane is venting. Often rod packing vents are manifolded together, though they are sometimes separate, so it is important for the reporter to know the design to fully and accurately measure the emissions from these vents.

4. *Compressor Dry Seal Centrifugal Emission Factors*

We support EPA's proposal to add dry seal vents to the defined compressor sources for centrifugal compressors and to require measurement of volumetric emissions from the dry seal vents in both operating-mode and in standby-pressurized-mode. As EPA notes, while dry seal centrifugal compressors have lower emissions than wet seal centrifugal compressors, these emissions are not negligible and thus should be accounted for.

5. *Standby Pressurized Mode for Reciprocating and Wet Seal Oil Degassing Vent*

While the standby pressurized mode is less common, emissions do occur during standby mode in centrifugal compressors, and adding this will provide clear guidance to operators. We therefore support this proposal.

L. <u>Storage tanks</u>

EPA has proposed several updates to the reporting requirements for storage tanks that will improve the accuracy of data collected, and we generally support these updates. First, EPA provides clarification for operators on how to estimate the amount or gas that is captured using a vapor recovery unit or sent to a flare. Many operators report that the vapor recovery system or flare is capturing 100% of the gas; however, there is ample evidence that VRUs and flares do not always operate with perfect efficiency.[137] This can occur when the VRU or flare is bypassed, is malfunctioning, or when a thief hatch is left open. Thus, it is critical that operators fully account for these periods when estimating the total amount of gas sent to control and the amount of gas directly vented.

We support EPA's proposal to add a new data element that will track the number of open or unseated thief hatches and the total volume or gas that is vented through open or unseated thief hatches. This will improve overall data quality and transparency, and is important because of the significant number of large emissions events that are caused by these sources.[138]

EPA has also proposed updates related to emissions from malfunctioning separator dump valves. Operators are already required to report vented emissions from malfunctioning separator dump valves, but there

[137] Zavala-Araiza et al., *Super-emitters in natural gas infrastructure are caused by abnormal process conditions*, 8 Nat. Comms. 14012 (2017), https://www.nature.com/articles/ncomms14012; Lyon et al., *Aerial surveys of elevated hydrocarbon emissions from oil and gas production sites*, 50 Env. Sci. Tech. 4877–4886 (2016), https://pubs.acs.org/doi/10.1021/acs.est.6b00705; Rutherford et al., *supra* note 59.
[138] *See, e.g.*, Zavala-Araiza 2017.

previously was no explicit mention of how to report emissions from malfunctioning separator dump valves that are flared. This is an important clarification and addition to the reporting program that we fully support.

EPA has proposed updates to the definition of the Onshore Natural Gas Processing industry segment to clarify that this segment is not required to report emissions from storage tanks. We do not support this and believe EPA should require reporting from storage tanks in this segment. During helicopter-based OGI flights conducted in 2021, EDF documented 30 emission counts from storage tanks at processing plants in the Permian Basin.[139] We also documented another dramatic tank emissions from a processing plant in Eunice, New Mexico in 2022.[140] We believe this to be a significant source of methane emissions and recommend adding reporting requirements for storage tanks in the Onshore Natural Gas Processing industry segment.

M. Gathering Lines

We encourage EPA to both use existing aerial data and collect new data to explicitly assess differences in gathering pipeline emissions across basins. Such analysis would help inform an updated national emission factor for gathering pipelines based on empirical measurement approaches. We also recommend that EPA require reporting on station count in gathering. This would be helpful data for further assessing emissions from this segment.

A recent study used methane emission measurements collected from four discrete aerial campaigns in 2019-2021 alongside GIS data of pipeline mileage to calculate a methane emission factor for gathering pipelines in the Permian Basin.[141] From each campaign, they quantified emission factors ranging from 2.7 to 10.0 metric tons CH4 per kilometer per year (4,300 to 16,000 kilograms CH4 per mile per year), which are 14-52 times higher than the EPA's GHGI estimate of 310 kilograms CH4 per mile per year, which considers both fugitive emissions and blowdown or other maintenance events. The study showed that a relatively small number of pipeline emission sources were responsible for a large fraction of total methane flux originating from pipelines, demonstrating that, as in the case of other oil and gas infrastructure,[142] a large sample size is necessary to identify rare but large emission sources.

To our knowledge, this is the first published, peer-reviewed study that explicitly estimates an emission factor for gathering pipelines, and its results imply that the GHGI methane emission factor for gathering pipelines is a severe underestimate, in light of what was observed in multiple aerial campaigns. Importantly, the new study still found severely elevated emission factors even when the analysis was restricted to sources observed to be emitting on more than one day, thereby more credibly focusing on fugitive emissions, rather than on blowdowns or other temporary maintenance events.

[139] *See* Attachment B - LSI Tank Emissions from Processing Plants.
[140] *See* NM_162 IR (video on file with EDF).
[141] Yu et al., *Methane Emissions from Natural Gas Gathering Pipelines in the Permian Basin*, Environ. Sci. Technol. Lett. (Oct. 4, 2022), https://doi.org/10.1021/acs.estlett.2c00380.
[142] Chen et al., *Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey*, *Environ. Sci. Technol.* 2022, 56, 7, 4317–4323 (2022), https://doi.org/10.1021/acs.est.1c06458; Cusworth et al., *Strong Methane Point Sources Contribute a Disproportionate Fraction of Total Emissions Across Multiple Basins in the United States*, PNAS (Sept. 13, 2022), https://doi.org/10.1073/pnas.2202338119.

This study offers a useful first look into quantifying gathering pipeline emissions using aerial measurement data, but there are two main limitations to note. First, although aerial remote sensing is useful for collecting a large sample size, the relatively high minimum detection limit of the aerial instrument suggests that the calculated emission factors do not incorporate small emission sources and are thus conservative estimates. Second, this study's observations and results are specific to the Permian Basin over the 2019-2021 period. However, Cusworth et al. (2022) used aerial methane measurement data from several U.S. basins and found significant gathering line emissions in regions beyond the Permian.[143]

N. Liquids Unloading

We support EPA's proposal to require reporting on the type of unloading that operators employ, including whether it is automated or manual unloading and whether the unloading is a plunger lift or non-plunger lift unloading. We also support EPA's proposal to require reporting of emissions from automated unloadings separately from manual unloadings. We agree that there could be significant differences in the number and duration of unloadings and differences in emissions between manual and automated plunger lift unloadings and liquids unloading emissions. We believe this additional granularity is important for understanding emissions and informing regulations.

EPA should align reporting under subpart W with that which will be required under OOOOb. In the proposed OOOOb, EPA has moved to require zero emission liquids unloading practices and determined that liquids unloading is a modification, meaning any well that undergoes liquids unloading will be subject to the OOOOb standard.[144] We supported EPA's Option 1 for regulating liquids unloading which would require all wells undergoing liquids unloading to report the number of unloadings and the methods used, including wells using non-emitting methods. We supported the uniform reporting requirement of Option 1, because, as EPA recognized, venting can occur unintentionally even when a non-emitting method is used. The proposed OOOOb standards for liquids unloading would require owners and operators to record and report these instances, as well as document and report the length of venting, and what actions were taken to minimize venting to the maximum extent possible.

In situations where it is technically infeasible or not safe to perform liquids unloading with zero emissions, EPA proposed to require that owners or operators (1) document why it is infeasible to utilize a non-emitting method due to technical, safety, or economic reasons; (2) develop best management practices (BMPs) that ensure that emissions during liquids unloading are minimized including, at a minimum, having a person on-site during the liquids unloading event to expeditiously end the venting when the liquids have been removed; (3) follow the BMPs during each liquids unloading event and maintain records demonstrating they were followed; and (4) report the number of liquids unloading events in an annual report, as well as the unloading events when the BMP was not followed.[145]

This information, which will already be collected from every well undergoing liquids unloading through OOOOb, should also be reported to the GHGRP. In particular, we think it is important for EPA and

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[143] Cusworth et al., *Strong Methane Point Sources Contribute a Disproportionate Fraction of Total Emissions Across Multiple Basins in the United States*, PNAS (Sept. 2022), https://www.pnas.org/doi/10.1073/pnas.2202338119.
[144] 86 Fed. Reg. at 63,179.
[145] *Id.*

stakeholders to understand how often non-emitting methods are being used and how often those methods fail and result in vented emissions. For wells where it is technically infeasible or unsafe to use non-emitting methods, it will be important for EPA to understand the emissions and also understand whether the BMPs are reducing emissions. Including the same data elements reported for OOOOb in subpart W will allow stakeholders to readily access this information and evaluate emissions from various liquids unloading practices.

O. LNG & Natural Gas Processing

EPA currently requires operators to report CO2 emissions from Acid Gas Removal Units (AGRUs) under subpart W for the following Oil and Gas industry segments: Onshore Petroleum and Natural Gas Production, Onshore Natural Gas Processing, and Onshore Petroleum and Natural Gas Gathering and Boosting. EPA proposes a number of updates to improve CO2 emissions estimation from AGRUs and requests comments on other emissions sources in the LNG Import/Export industry segment that should be added to Subpart W, which we comment on below.

1. *Requiring LNG Import/Export Facilities to Report CO2 Emissions from AGRUs*

We support EPA's proposal to include reporting of CO2 emissions from vents from Acid Gas Removal Units (AGRU) at LNG Import/Export facilities. Facilities in the Onshore Petroleum and Natural Gas Production, Onshore Natural Gas Processing, and Onshore Petroleum and Natural Gas Gathering and Boosting segments of the Oil and Gas industry are already required to report CO2 venting from AGRUs, and the LNG Export/Import segment is also a large source of emissions from AGRUs. The proposal will require LNG Export/Import facilities to use one of the four calculation methods currently provided in 40 C.F.R. § 98.233(d) and report emissions as currently provided in 40 C.F.R. § 98.236(d), which we support.

2. *AGRU Solvent Reporting Guidelines*

We support EPA's proposal to replace the requirement to report solvent weight with solvent type, and with specific amine-based solvents, the general composition. The solvent weight requirement did not previously indicate how the operator should calculate the value, and it was applied inconsistently among operators. The solvent weight did not provide enough details about the AGRU to verify reported data and characterize AGRU vent emissions. This change proposed by EPA will provide clarity and improve the accuracy of data collected.

3. *Require Facilities to Report Methane Emissions from Acid Gas Removal Units Vents*

Methane emissions reporting from AGRU vents is not currently required, but it is a significant source of methane emissions. For example, a natural gas processing facility with a throughput of over 700 MMSCD of gas with a composition of over 60% CO2, ~20% methane, over 7% nitrogen, and remaining balance with hydrogen sulfide and helium would have a significant amount of methane emissions from the AGRU vents. The facility in this example contains two identical natural gas processing trains to process the estimated 700 MMSCFD incoming gas flow rate. It is important to recognize that these methane emission flow rates can vary dramatically by site because they are dependent on the feed gas composition, acid gas removal technology, AGRU separation efficiency, and amount of CO2 used for enhanced oil recovery (EOR) or other forms of utilization/sequestration. Additionally, separation efficiency can be affected by process flow rates and conditions, which are set based on product specifications.

A study released by EPA/GRI in 1996 to quantify methane emissions from AGRUs (Myers, 1996), assumes that only 18% of the vented methane from the AGRU is released into the atmosphere resulting in an emission factor of 6,083 scfd/AGRU. This significantly underestimates emissions measured at some natural gas processing facilities and incorrectly assumes that facilities only vent a fraction of the methane emissions from the AGRU. The study also estimates the emission factor of 965 scf methane/1 MMSCF of treated gas for an AGRU vent in a natural gas processing facility venting 100% of the methane emissions to the atmosphere. Due to the lack of detailed information about the fraction of methane emissions from the AGRU vent that is vented directly to the atmosphere, EPA should strongly considered adding methane reporting requirements from all AGRU vents to more accurately characterize methane emissions from these facilities.

For ARGU vents that are directly releasing methane into the atmosphere, EPA should require operators to use continuous emissions monitoring systems (CEMS), vent meters, simulation software, or calculation methods that use mass balance equations to account for the vented methane emissions from the AGRU vents. In cases where details about the facilities are unknown to calculate emissions using mass balance equations shown below, EPA should consider proposing segment-specific robust emission factors that are reflective of average methane emissions from AGRU vents for each segment.

4. *Require Facilities to Report Methane Emissions from Nitrogen Removal Units (NRUs)*

Nitrogen Removal Units (NRU), also known as Nitrogen Rejection Units, are process units in natural gas processing and LNG production segments of the oil and gas industry used to decrease the nitrogen content in the natural gas to meet the desired heating value specifications established by the operator. The capacity of the NRU is designed depending on the nitrogen concentration in the feed gas entering the facility and a desired heating value of the natural gas product. For examples, a natural gas processing facility with a throughput of over 700 MMSCD of gas with a composition of over 60% CO_2, ~20% methane, over 7% nitrogen, and remaining balance with hydrogen sulfide and helium goes through several treatment processes to remove contaminants and achieve the desired heating value for their product. After the natural gas is stripped of hydrogen sulfide, carbon dioxide and water at the beginning, the composition of the natural gas becomes ~68% methane, 30% nitrogen, and 2% helium, and it goes through a cryogenic process to remove the excess nitrogen in the natural gas. During this separation process, a fraction of methane is vented with nitrogen that is removed from the natural gas.

Recognizing the vast variabilities in facility operations, it is critical to mandate reporting of the methane emissions from the NRU vent from all onshore natural gas processing and LNG export/import facilities to improve the accuracy of the GHGRP inventory and better understand the mitigation opportunities to reduce methane from NRUs. EPA should require operators to use a continuous emissions monitoring system (CEMS), vent meter, a simulation software, or calculation methods that use mass balance equations to account for and report the vented methane emissions from all NRU vents. EPA must take measures to investigate how to improve methane emissions reporting requirements from the vent stack associated with NRUs.

5. *Require LNG Import/Export Facilities to Continuously Monitor Engine Emissions*

EPA should require LNG Import/Export facilities to continuously monitor engine emissions. Stationary fuel combustion can be a major source of greenhouse gas emissions at LNG import and export facilities as they are used to supplement power and energy to the facility by combusting the biol-off gas produced from on-site storage tanks. During combustion of natural gas, methane is emitted in significant quantities due to fugitive leaks from the equipment and incomplete combustion. We strongly urge EPA to require continuous emissions monitoring for methane emissions in the exhaust of stationary fuel combustion equipment, as currently required for CO2 in all LNG facilities to accurately account for fugitive methane leaks.

V. Subpart X - Petrochemical Production

EPA proposes several amendments to petrochemical production flare reporting, product reporting under the optional ethylene combustion methodology, and emissions calculation requirements for flares. As discussed below, we support several of these proposed amendments but urge EPA to adopt a more inclusive approach to flare calculation and reporting to ensure more accurate emission estimates from petrochemical production.

A. Flare Reporting

We support EPA's proposal to add a reporting element in 40 C.F.R. § 98.246(b)(7) and (c)(3) for each flare that is reported under the CEMS and optional ethylene combustion methodologies. This would require reporters to also report estimated fractions of the total CO2, CH4, and N2O emissions from these flares that are due to combusting petrochemical off-gas. EPA believes the current requirements result in an overestimate of emissions attributed to a petrochemical process unit when the flare is not dedicated to a petrochemical process unit, particularly if the flare is also used to combust off-gas from non- petrochemical process units. According to EPA, the proposed requirement would allow the fractions attributed to each petrochemical process unit that routes emissions to the flare to be estimated using engineering judgment and would allow more accurate quantification of emissions both from individual petrochemical process units and from the industry sector as a whole. We support these updates and suggest further improvements below.

EDF supports improving the accuracy of flare reporting. However, EPA's proposal does not clearly distinguish between petrochemical off-gas and non-petrochemical off-gas when various units capable of such off-gassing are present at a given facility. If non-petrochemical units are present whose function is to support the petrochemical units, the off-gases from such units–if flared–should be accounted for in the petrochemical unit off-gases. We encourage EPA to provide more details about the extent of this overestimation that it seeks to correct via this proposed distinction.

EPA further notes that reporters will use "engineering judgment" to attribute fractions "to each petrochemical process." We are concerned that deference to engineering judgment could lead to inaccurate reporting. Accordingly, EPA should require that any such engineering judgment be based on supported, site-specific, and disclosed facts.

B. Ethylene Production Process Product Reporting

We support EPA's proposal to add a requirement in 40 C.F.R. § 98.246(c)(6) to report the names and annual quantity (in metric tons) of each product produced in each ethylene production process under the optional ethylene combustion methodology. We agree that this proposed change would make product reporting under the optional ethylene combustion methodology consistent with product reporting requirements under the CEMS and mass balance reporting options, and that data on the quantities of all products will be useful in informing future policy decisions.

C. Flare Emissions Calculation Requirements

We offer two suggestions on EPA's proposed revisions to 40 C.F.R. § 98.243(b)(3) and (d)(5). First, we urge EPA to require subpart X reporters to report emissions attributable to the combustion of pilot gas. The quantity of pilot gas and its composition should be known to operators and the combustion emissions can be estimated with simple calculations. Although pilot gas combustion may not result in the same volume of greenhouse gas emissions as flaring, as flaring is reduced the emissions from pilot gas combustion will begin to represent a larger fraction of overall flaring emissions.

Second, we ask EPA to revisit the exclusion of SSM events based on the 500,000 scf/day threshold as currently noted in equation Y–3. The 500,000 scf/day threshold is not clearly supported by any technical basis. Spread uniformly over the course of a day, this flow is slightly under 350 scf/minute. This is not an insubstantial flow of waste gases. Depending on the composition of this waste gas flow, substantial quantities of greenhouse gas emissions can result. Excluding gas released during SSM events of less than 500,000 scf/day from equation Y–3 is inconsistent with EPA's overall goals of understanding emissions and reducing flaring at all industrial facilities including subpart X and Y reporting facilities.

VI. Subpart Y - Petroleum Refineries

EPA proposes several revisions to subpart Y, each of which is addressed in detail below. While we support EPA's proposed clarifications and additional reporting requirements, we ask that EPA revisit the exclusion of SSM events less than 500,000 scf/day from equation Y–3. We also request additional information on EPA's proposal to permit the use of mass spectrometer analyzers to determine gas composition and molecular weight without the use of a gas chromatograph.

A. Additional Reporting Requirements for Delayed Coker Unit (DCU) Data Collection

We support EPA's proposed additional reporting requirements for DCU data collection, including requiring facilities to report, for each DCU: (1) the internal height of the DCU vessel; and (2) the typical distance from the top of the DCU vessel to the top of the coke bed (i.e., coke drum outage) at the end of the coking cycle (feet). We agree with EPA that these new elements will allow EPA to estimate and verify the reported mass of dry coke at the end of the cooling cycle as well as the reported DCU emissions.

B. Revisions to Variables for DCU Data Collection

We also support the addition of the phrase "or draining" to the definitions of ''Mwater'' and ''Hwater'' in equation Y– 18b. We ask that the steam generation model used to account for the heat balance at a DCU use site-specific data to the maximum extent possible. Thus, we also support the use of the "fcoke" variable to account for situations when the coke bed is not fully submerged. However, the "universality" of this parameter should not mean that a single value be used in all cases. Rather, the value of the "fcoke" parameter should be based on site-specific data reflecting site-specific, typical practices including the degree to which the coke bed is or is not submerged.

C. Coke Burn-off Emissions Language

We support EPA's proposal to add clarifying language to 40 C.F.R. § 98.253(c) and 98.253(e) to reiterate the language from 40 C.F.R. § 98.252(b) that the emissions being quantified in these paragraphs are coke burn-off emissions rather than emissions that may occur from other venting events. We ask EPA to clarify where the greenhouse gas emissions from the other venting events at these units, as applicable, would be addressed.

D. Exclusion of SSM Events Less than 500,000 scf/day

As explained above, we do not support the exclusion of events with gas flows of 500,000 scf/day or below from equation Y–3. EPA should require the inclusion of all gases, including purge and sweep gases as was revised in 2016, as well as pilot gas. We do not believe that achieving consistency requires perpetuating the exclusion of SSM events less than 500,000 scf/day. SSM events, even those below 500,000 scf/day, can lead to significant flaring and harmful emissions that EPA should gather data on to better understand and use to inform regulatory approaches that minimize or eliminate such events. EPA should at least explain why reporting of emissions from flaring during these SSM events should not be reported.

E. Cross-reference in 40 C.F.R. § 98.253(i)(5)

We support correcting the erroneous cross-reference in 40 C.F.R. § 98.253(i)(5) relating to the term Mstream in equation Y– 18f for DCUs.

F. Recordkeeping to DCU emission calculations at 40 C.F.R. § 98.257(b)(53)

We support the proposed recordkeeping requirement for the "fcoke" variable and removal and reservation of the recordkeeping requirements in § 98.257(b)(54)-(56) since equation Y–19, the process vent calculation method, is no longer used to calculate DCU emissions.

G. Mass Spectrometer Analyzers

We ask that EPA provide additional information regarding its proposal to allow the use of mass spectrometer analyzers to determine gas composition and molecular weight without the use of a gas chromatograph. Specifically, we request information demonstrating that the use of direct mass spectrometer analyzers alone provides the same level of accuracy in determining the composition of a gas stream as would be possible by first using gas chromatographic preseparation followed by a mass spectrometer analyzer. While we agree that reduced cycle time is a desirable goal, it is not appropriate if the underlying accuracy of the gas composition is compromised. Similarly, just because direct mass spectrometry without gas chromatography is used by refinery operators to determine gas composition , as noted by EPA, it does not mean that such determinations are accurate or accurate enough for the determination of greenhouse gas emissions. Therefore we ask that EPA provide support for the level of accuracy in the proposed approach to determining gas composition as compared to the combined gas chromatograph and mass spectrometer approach.

VII. Subpart HH - Municipal Solid Waste Landfills[146]

EPA's proposed changes to landfills emission reporting requirements in subpart HH are intended to "improve the quality of data collection under the GHGRP."[147] We are concerned, however, that the changes fail to address significant inaccuracies in the reported emissions from landfills, leading to persistent underestimation of landfill methane emissions that do not reflect actual observed emissions.

In subsequent sections, we A) highlight the recent top-down studies documenting landfill methane emissions that often exceed reported emissions; B) discuss specific issues with the current and proposed assumptions and reporting methodologies under subpart HH; and C) suggest changes to bring reported emissions into better alignment with real-world emissions, including by improving the reporting methodologies, requiring waste characterization data, gathering more information on flared landfill gas, and requiring large landfills to use advanced methane detection technologies.

A. Reported Emissions Do Not Reflect Observed Emissions

Recent advances in methane detection technologies have improved our ability to observe and quantify methane emissions from individual landfills.[148] Multiple studies find little correlation between top-down observations and emissions calculated under the subpart HH equations. In some cases, observed emission rates are orders of magnitude higher than those reported under GHGRP, at least in part reflecting variable large emission events that bottom-up models fail to capture.[149]

The Next Generation Airborne Visible/Infrared Imaging Spectrometer (AVIRIS-NG) is one example of airborne instrument technology that can remotely sense methane emissions with high spatial resolution from individual sources.[150] Top-down observations can then be used to derive annual emission rates that can be incorporated into greenhouse gas estimates, although there are some limitations in sensitivity and measurement frequency that we discuss further below.

For example, the California Methane Survey flew AVIRIS-NG, mounted on an aircraft, over 270 landfills and 166 organic waste facilities repeatedly during 2016 through 2018 to quantify their contribution to the state methane budget.[151] The survey found methane "super-emitter" activity in every surveyed sector, where a few point sources had an outsized impact on overall emissions (e.g., 10% of sources represented 60% of

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[146] EDF worked with RMI in developing comments on subpart HH and our submissions contain similar recommendations.

[147] 87 Fed. Reg. 36,920, 37,008.

[148] Cusworth et al., *Using Remote Sensing to Detect, Validate, and Quantify Methane Emissions from California Solid Waste Operations*, 15 Env. Res. Letters 054012 (2020), https://iopscience.iop.org/article/10.1088/1748-9326/ab7b99; White House Office of Domestic Climate Policy, U.S. Methane Emissions Reduction Action Plan (2021) www.whitehouse.gov/wp-content/uploads/2021/11/US-Methane-Emissions-Reduction-Action-Plan-1.pdf.

[149] *See, e.g.*, Amini et al., *Comparison of First-order-decay Modeled and Actual Field Measured Municipal Solid Waste Landfill Methane Data*. Waste Manag. 2013 Dec ;33(12):2720-8. https://pubmed.ncbi.nlm.nih.gov/23988298/; Duren, et al., *California's Methane Super-emitters*. Nature 575, 180–184 (2019), https://doi.org/10.1038/s41586-019-1720-3.

[150] Cusworth et al., *Using Remote Sensing*, *supra* note 148.

[151] *Id.*; The California Methane Survey (2020), https://www.energy.ca.gov/sites/default/files/2021-05/CEC-500-2020-047.pdf.

emissions). Specifically, 30 landfills and 2 composting facilities were the largest methane point source emitters in the state by sector (43% of the total emissions in the study), exhibiting persistent, potentially anomalous activity that was not adequately accounted for in state or national inventories.[152] Across six representative California landfills in the survey, four had reported emissions to the GHGRP that were well below AVIRIS-NG and other aircraft-based observations, while two landfills reported emissions slightly higher than observed (Figure 6).[153]

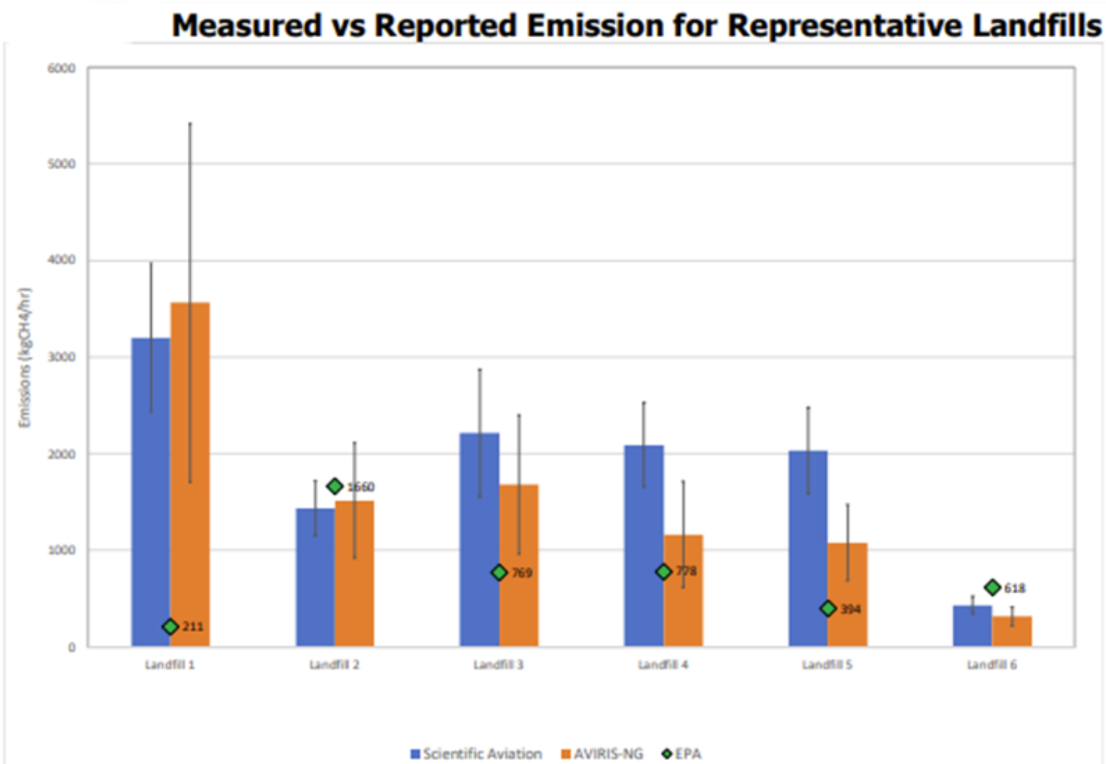

Figure 6: Measured vs. Reported Emissions at Six California Landfills

Site-level aerial data can drive design and operational improvements at high-emitting landfills. For example, following the initial flyovers, Sunshine Canyon landfill updated its covers, collection pipes, and well design, contributing to a 55-60% reduction in methane emissions as corroborated by follow-up AVIRIS-NG flights.[154]

Beyond California, emissions observed by AVIRIS-NG show little correlation with those reported under GHGRP. Figure 7 compares observed and modeled emissions at select landfills in Arizona, California, Colorado, Louisiana, New York, Ohio, Pennsylvania, and Utah between 2016 and 2021. About half of the sampled landfills had observed emissions higher than those reported under GHGRP across multiple revisits, and on a weighted average, airborne surveys estimated emissions 3.5 times higher than the bottom-up estimates in the study.[155] Furthermore, AVIRIS-NG estimates capture point source emissions (i.e.,

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[152] *Id.*
[153] *Id.*
[154] Cusworth et al., *Using Remote Sensing*, *supra* note 148; Eugene Tseng, *When View From Space*, Nov. 2020, https://www.mswmanagement.com/landfills/odor-dust-control/article/21157296/when-viewed-from-space.
[155] RMI, Carbon Mapper, IG3IS "Key Strategies for Mitigating Methane Emissions from Municipal Solid Waste,"

emissions from an area typically less than 10 meters with an emission rate above ~50 kg/h CH4) and are therefore generally conservative, likely underestimating total annual emissions from sources such as landfills that often have diffuse emissions spread over a larger area.

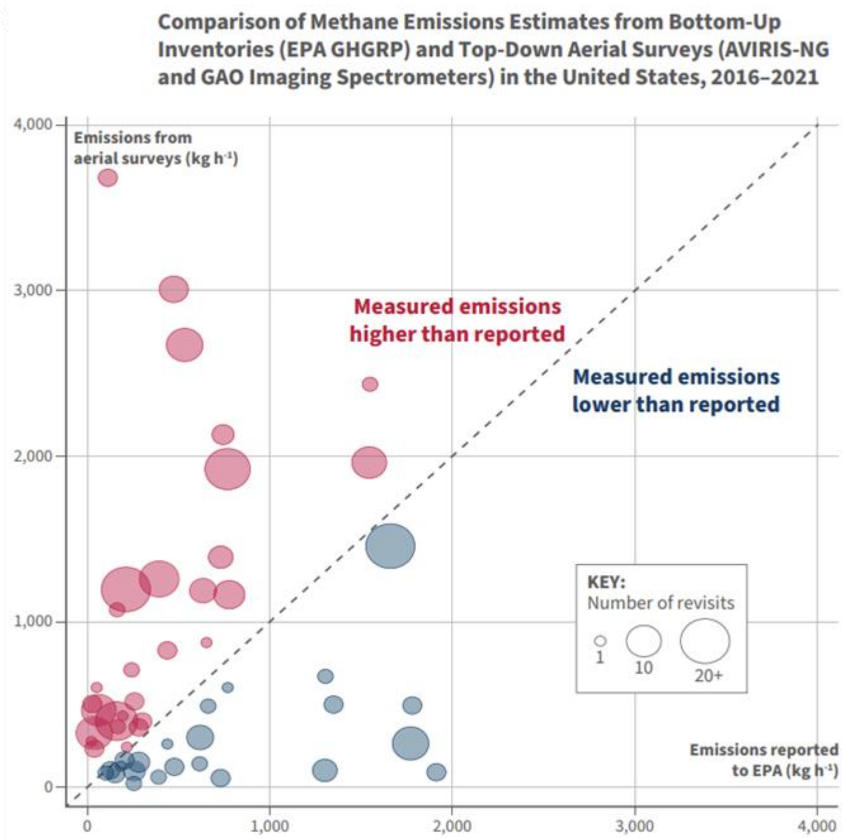

Figure 7: Comparison of Methane Emissions Estimates from Bottom-Up Inventories and Top-Down Aerial Surveys[156]

Additional studies in Maryland, Texas, and Indiana found large discrepancies between modeled and observed methane emissions at landfills. In Maryland, the methane emission rates observed during 48 mass balance aircraft flights over eleven landfills were about 1.8 times higher than emission rates reported to GHGRP. One Maryland landfill had observed emissions 9 times higher than were reported to GHGRP.[157] In Texas, aircraft-based observations of methane emissions at three landfills were about 2.8 times higher than reported GHGRP values.[158] At a central Indiana landfill, emissions reported to GHGRP (based on equation HH-8) between 2010 and 2014 fell generally below aircraft-based measurements, and at or below

July 2022; Carbon Mapper, "Methane, CO2 Data, Global Open Portal, Carbon Mapper" (last accessed June 2, 2022), https://carbonmapper.org/data/.
[156] Carbon Mapper, *Methane, CO2 Data, Global Open Portal, Carbon Mapper* (last accessed June 2, 2022), https://carbonmapper.org/data/.
[157] Ren et al., *Methane Emissions from the Baltimore-Washington Area Based on Airborne Observations: Comparison to Emissions Inventories*, J. Geophys. Res.-Atmos. 123, 8869–8882 (2018), https://agupubs.onlinelibrary.wiley.com/doi/10.1029/2018JD028851.
[158] Lavoie et al., *Aircraft-Based Measurements of Point Source Methane Emissions in the Barnett Shale Basin*, *Environ. Sci. Technol.* 2015, 49, 13, 7904–7913 (2015), https://doi.org/10.1021/acs.est.5b00410.

the lower 10% percentile of observations from other direct measurement techniques at the landfill over the same period.[159]

The substantial body of top-down and direct measurement data shows significant landfill emissions are not being captured by the existing reporting requirements. In the following sections, we outline the issues with existing reporting methodology and provide recommendations for improvement.

B. Concerns with EPA's Emissions Estimation Methodology

Subpart HH uses a first order decay model as one of two methods to estimate methane generation from MSW landfills. This model considers (1) the quantity of solid waste landfilled, (2) the degradable organic carbon (DOC) content of that waste, and (3) the first order decay rate (k) of the DOC. Table HH–1 of subpart HH contains DOC and k values that a reporter must use to calculate their methane generation based on the types of waste disposed of at that landfill and the climate in which the landfill is located. The reporter multiplies: (quantity of waste) x (degradable carbon content for the waste stream (DOC)) x (decay rate for that waste stream under applicable climatic conditions (k)), which generates an estimate of methane generation by the landfill.

EPA has proposed the following changes to these values:

- DOC. Industry commenters have argued that certain DOC factors overestimate the organic fraction of waste and therefore lead to overestimating emissions. EPA is therefore proposing to lower DOC factors for certain waste streams while raising the DOC factor for "uncharacterized" waste streams.

- k. EPA is also proposing to revise k values, which are applied based on the composition of the waste and the moisture content of the waste within the landfill. EPA has proposed to increase the k values, meaning that waste is assumed to decay and cause emissions faster.

EPA states that lowering the DOC values and raising the k values will affect closed and open landfills in the following different ways:

- Active landfills. The higher k values will increase the emissions calculated for open, active landfills. The higher k values imply that the organic material will degrade more quickly than predicted when using lower k values. This leads to greater calculated emissions from active landfills.

- Closed landfills. With higher k values, less degradable waste is calculated to remain in the landfill by the time it closes (i.e., no longer receives wastes) and the remaining degradable waste that is present in the closed landfill will decompose more quickly. This tends to reduce the emissions calculated for closed landfills, which may allow closed landfills to more quickly fall below the reporting threshold.

The cumulative estimated emissions from a landfill over its entire lifecycle (active and closed periods) depend on the amount of degradable organic material placed in the landfill, which is represented by the

[159] Cambaliza et al., *Field Measurements and Modeling to Resolve M2 to Km2 CH4 Emissions for a Complex Urban Source: An Indiana Landfill Study*, Elementa: Science of the Anthropocene (2017), https://doi.org/10.1525/elementa.145.

DOC value applied to the total quantity of waste received. Thus, lower DOC values should reduce the cumulative emissions reported for a given landfill over all reporting years.

For landfills with gas capture and collection systems (GCS), EPA also requires operators to estimate the volume of methane generated by back-calculating from the volume of methane captured, applying a specified assumed collection efficiency that depends on the landfill cover condition. The collection efficiency is specified as 0% for areas without active gas collection, 60% for areas with active collection and daily soil cover, 75% for areas with active collection and intermediate soil cover, and 95% collection for areas with active collection and final soil cover.[160]

EPA directs operators to calculate the landfill's emissions using each of these two methods for calculating the methane generation (modeled using the first-order decay equation and back-calculated using the assumed capture efficiency). The operator must then report emissions from the landfill using the approach that "best represents the emissions from the landfill."[161]

It is widely acknowledged by EPA and others that there is high uncertainty around the estimates of methane generation by (and thus emissions from) landfills that are based on the first order decay model, which underlies equation HH-1 in subpart HH.[162] In this section, we discuss specific concerns about the waste composition, oxidation, and collection efficiency assumptions.

With respect to the back-calculation method used in equation HH-7, EPA has suggested that there is "less uncertainty" in EPA's GHGRP data (which is largely derived from the back-calculation method) "because this methodology is facility-specific, uses directly measured CH4 recovery data (when applicable), and allows for a variety of landfill gas collection efficiencies, destruction efficiencies, and/or oxidation factors to be used."[163] Unfortunately, however, while the CH4 recovery volumes are indeed directly measured, and thus should be relatively reliable, deriving estimates of both CH4 generation and emissions from the amounts recovered depends entirely on the accuracy of the assumed collection efficiencies, destruction efficiencies, and oxidation factors applied, each of which appear to be far more uncertain than EPA implies. EPA's approach thus uses highly uncertain "unknown" values (e.g., the percentage of generated methane that is oxidized, captured, and destroyed at a specific landfill over time) and one "known" value (the amount of methane captured) to calculate another unknown, and the result cannot be anything other than highly uncertain.

In addition, the directive to the operator to select between the two approaches for estimating methane generation – and hence emissions – does not include any guidance regarding which approach might "better represent" a given landfill's emissions. In practice, it appears highly likely that most operators simply select the lower estimate (EPA notes in the proposal that over 70% of operators report emissions based on the back-calculation approach).

These problems are exacerbated by the fact that the current and proposed estimation approaches do not account for the emissions from abnormal operational conditions, such as large leaks, which have been identified through observations as the source of massive quantities of emissions, as discussed above.

[160] 40 C.F.R. Part 98, Subpart HH, Table HH-3.
[161] 40 CFR § 98.346(i)(13).
[162] *See, e.g.*, National Academies, *Improving Characterization of Anthropogenic Methane Emissions in the United States* (2018), https://nap.nationalacademies.org/catalog/24987/improving-characterization-of-anthropogenic-methane-emissions-in-the-united-states; EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2020*, https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2020.
[163] *Id.*

1. *Waste composition*

Waste composition, specifically the degradable organic carbon (DOC) content in landfilled waste, is a key driver of methane generation potential. Under subpart HH (Equation HH-1), reporters can choose one of three options to characterize their waste:

- The Bulk Waste option assumes one stream of waste that contains a mixture of organic and inorganic waste. Reporters use a single default value for DOC and choose one of three decay rate (k) values based on annual rainfall.
- The Modified Bulk Waste option allows facilities to break down their waste stream into organic waste, construction & demolition (C&D) waste, and inert waste. Reporters use a higher DOC for the organic waste, a lower DOC for the C&D waste, and a DOC of zero for the inert waste. The k values for organic and C&D waste are also based on annual rainfall.
- The Waste Composition option further breaks down the waste stream into subcategories, each with its own DOC and k values (e.g., food, garden, paper, wood, and inert waste) and uses bulk waste assumptions when compositional data is not available.

EPA is proposing changes to DOC and k values, based largely on a multivariate analysis that takes 2012-17 GHGRP data and optimizes DOC and k to minimize the difference between methane generation estimates in HH-1 and HH-7 (the back-calculated approach). The agency also reviewed updated municipal solid waste composition data from 2011 to 2015 under the *Advancing Sustainable Materials Management* survey, and the k values used in other countries' inventories and as recommended by the IPCC.

Specifically, EPA proposes to lower the Bulk Waste DOC to 0.17 from 0.20 and lower the Modified Bulk Waste (organic) DOC to 0.27 from 0.31. EPA also introduces an uncharacterized waste category under the Waste Composition option with a DOC of 0.32. EPA's proposed changes to k values reflect the same multivariate analysis and the proposed revisions to DOC (as k values depend on waste composition).

There are several challenges with EPA's approach to the DOC and associated k values. First, waste composition can vary meaningfully by landfill, due to differences in population, industry, and the state and local regulatory landscape.[164] Default bulk and modified bulk DOC values fail to capture the site-level differences in waste composition that can impact methane generation. This is especially important given the vast majority of landfills use the bulk or modified bulk default values under GHGRP. A 2018 study found that of 1,147 landfills reporting to the GHGRP, nearly 99% reported no more than three waste types at any point in their history, and most sites (57%) reported a single, lump sum waste quantity each year. Importantly, data gathered from state environmental agencies showed more detail in terms of major waste types landfilled, suggesting landfill owners and operators have more knowledge of different waste type quantities than what is reflected in the GHGRP data set.[165]

Second, the newly proposed DOC and k values are based on a multivariate analysis of previously reported data under GHGRP (2012-2017). This analysis optimizes DOC and k to align with the back-calculated methane generation estimates under Equation HH-7, even though HH-7 relies on highly uncertain collection efficiency rates, as we discuss further below. EPA cross-references the multivariate analysis with 2011-2015 data from the *Advancing Sustainable Materials Management* survey, but this data is gathered using a

[164] EPA MSW Characterization Methodology, https://www.epa.gov/sites/default/files/2015-09/documents/06numbers.pdf.

[165] Jon T. Powell et al., *Quantity, Components, and Value of Waste Materials Landfilled in the United States*, 23 J. Indus. Ecology 466 (2018), https://onlinelibrary.wiley.com/doi/10.1111/jiec.12752.

materials flow approach (leveraging nationwide production data with adjustments for imports, exports, and diversion) rather than site-specific data.[166]

As we recommend in Part C below, to improve the accuracy of methane generation estimates, EPA should collect comprehensive waste characterization data from landfills to inform more representative DOC and k values for the Bulk Waste options, and also consider requiring reporters to use the Waste Composition option, especially given many landfills and municipalities collect this data already.

2. *Oxidation Fraction*

In both the first order decay and back-calculation approaches, subpart HH reporters can offset their methane emissions estimates with the oxidation assumptions under Table HH-4, ranging between 0% and 35%, based on cover stage, cover material, and methane flux rate.

While methane oxidation can play an important role in reducing methane emission from landfills, estimation of methane oxidation is complicated by large observed variability.[167] A typical assumption is that 10% of methane is oxidized in landfills.[168] However, experts have suggested that relying on a single fixed value, or narrow set of fixed values, is not appropriate.[169] Methane oxidation relies on the appropriate species of methanotrophs being present and conditions to support growth of these species. Methanotrophs can be impacted by presence of toxic chemicals, soil temperature, and soil moisture.[170] Ideal soil temperature is 25-35°C and soil moisture is 10-20%.[171] Due to the dependence of methane oxidation on soil temperature and moisture, experts have suggested that rigorous models are needed to estimate methane oxidation over time that account for temporal variations.

While some research has suggested average values of methane oxidation of 30%, observations range from negligible to more than 30%.[172] Limited oxidation was cited as a likely cause of underestimation of methane

[166] EPA MSW Characterization Methodology, https://www.epa.gov/sites/default/files/2015-09/documents/06numbers.pdf

[167] Bala Y Sadasivam et al., *Landfill Methane Oxidation in Soil and Bio-based Cover Systems: A Review*, 13 Rev Environ Sci Biotechnol 79 (2014), https://doi.org/10.1007/s11157-013-9325-z; National Academies of Sciences, Engineering, and Medicine. (2018). *Improving Characterization of Anthropogenic Methane Emissions in the United States*. http://nap.edu/24987.

[168] IPCC (2006).

[169] NAS (2018).

[170] Charlotte Scheutz et al. (2004). Environmental Factors Influencing Attenuation of Methane and Hydrochlorofluorocarbons in Landfill Cover Soils. *Journal of Environmental Quality, 33(1): 72-79.* https://doi.org/10.2134/jeq2004.7200; Charlotte Scheutz et al. (2009). Microbial methane oxidation processes and technologies for mitigation of landfill gas emissions. *Waste Manag Res, 27(5): 72-79.* https://pubmed.ncbi.nlm.nih.gov/19584243/; Hanson et al. (1996). Methanotrophic bacteria. *Microbiological Reviews, 60(2).* https://journals.asm.org/doi/10.1128/mr.60.2.439-471.1996; Boeckx et al. (1996). Methane emission from a landfill and the methane oxidising capacity of its covering soil. *Soil Biology and Biochemistry, 28(10-11).* https://doi.org/10.1016/S0038-0717(96)00147-2.

[171] Charlotte Scheutz et al. (2004). Environmental Factors Influencing Attenuation of Methane and Hydrochlorofluorocarbons in Landfill Cover Soils. *Journal of Environmental Quality, 33(1): 72-79.* https://doi.org/10.2134/jeq2004.7200; Charlotte Scheutz et al. (2009). Microbial methane oxidation processes and technologies for mitigation of landfill gas emissions. *Waste Manag Res, 27(5): 72-79.* https://pubmed.ncbi.nlm.nih.gov/19584243/; Hanson et al. (1996). Methanotrophic bacteria. *Microbiological Reviews, 60(2).* https://journals.asm.org/doi/10.1128/mr.60.2.439-471.1996; Boeckx et al. (1996). Methane emission from a landfill and the methane oxidising capacity of its covering soil. *Soil Biology and Biochemistry, 28(10-11).* https://doi.org/10.1016/S0038-0717(96)00147-2.

[172] NAS 2018.

emissions in several California landfills located in hot, dry conditions.[173] Methane oxidation is also slowed in cold conditions (Scheutz et al. 2009). When applying a methane oxidation of 10%, Spokas (2015) found that sometimes methane was overestimated, and sometimes it was underestimated. This result points to the large uncertainty with methane oxidation estimation that is highly impacted by local conditions and site management. While methodologies exist that have been found to promote methane oxidation, those approaches have been observed to decrease in efficacy with time. We are concerned that conditions specified in Table HH-4 and the methane oxidation fraction linked to each set of specified conditions do not appropriately capture the wide range of variability of, and factors driving, oxidation rates, and thus do not adequately represent real-world oxidation rates at landfills.

3. *Collection Efficiencies*

It appears unlikely that EPA's assumed collection efficiencies are broadly representative of the collection efficiencies at U.S. landfills with active gas capture systems, and it is also unlikely that they provide reasonable estimates of the collection efficiency at an individual landfill. First, overflight monitoring suggests that overall emissions can be far higher than reported. While this could be due either to overestimated collection efficiency and/or underestimated methane generation values, since the generation values are commonly directly derived from the amount collected given an assumed collection efficiency value, collection efficiency overestimates are almost certainly at least part of the problem.

Second, studies show a wide range of collection efficiencies at different times after waste placement, in different areas of a given landfill, under different GCS systems, and with different types of cover materials.[174] While EPA's current values for collection efficiencies distinguish between daily, intermediate, and final covers, a recent study by Cal Polytechnic for the California Air Resources Board underscores the wide variation between collection rates under different types of covers in each of these categories.[175] The study found that "[f]lux and emissions of methane, nitrous oxide, and [non-methane volatile organic compounds] are highly variable at a given landfill and also between landfills."[176] Methane flux, which varied overall by an order of magnitude, varied by landfill and by cover category (daily, intermediate and final), as well as between different types of covers in a given category.[177] Across ten California landfills with active gas capture systems, the study found that collection efficiencies ranged from 23% to 91% (estimated based on aerial emissions measurements), 39% to 100% (estimated based on measured ground data that excluded emissions from the active face of the landfill), and 25% to 76% (estimated based on modeled methane generation).[178] The study concluded, "[d]ue to large uncertainty in modeling gas generation, the use of collection efficiency as a measure of emissions may not be reliable."[179]

[173] Kurt Spokas et al. (2015). From California dreaming to California data: Challenging historic models for landfill CH4 emissions. *Elementa: Science of the Anthropocene, 3: 000051.* https://doi.org/10.12952/journal.elementa.000051.

[174] *See, e.g.*, Barlaz et al., *Controls on Landfill Gas Collection Efficiency: Instantaneous and Lifetime Performance*, 59 J. Air & Waste Mgmt. Assoc. 1399 (Dec. 2009), https://doi.org/10.3155/1047-3289.59.12.1399; California Polytechnic State University, *Estimation and Comparison of Methane, Nitrous Oxide, and Trace Volatile Organic Compound Emissions and Gas Collection System Efficiencies in California Landfills* (Mar. 25, 2020) (https://ww2.arb.ca.gov/resources/documents/landfill-gas-research); Anaergia, *Updated California Landfill Capture Rate Determination* (Jan. 27, 2022).

[175] California Polytechnic State University, *supra* note 174.

[176] *Id.*

[177] *Id.* at 5.

[178] *Id.* at 12.

[179] *Id.* at 13

For example, the study found that, at the landfills it covered, conventional soil final covers were "significantly more effective" in reducing methane flux than alternative final covers, although both of these would have the same assumed collection efficiency under regulations.[180] Similar variations were found between alternative daily covers and conventional daily covers, and between soil intermediate covers versus intermediate covers with green waste or wet waste.[181] Yet the GHGRP requirements apply a single uniform value for every cover type that meets the minimum requirements in each category. Moreover, it appears that the uniform values of 60%, 75%, and 95% are quite high compared to the collection efficiencies estimated from aerial and ground emissions measurements.

Another study recently calculated the average methane capture rate for landfills in California using site-specific landfill gas measurement data from a NASA Jet Propulsion Laboratory study, the California Air Resources Board's Inventory of Waste-in-Place and Tier 1 Simplified Calculator for Organic Waste, and CalRecyle's 2018 Disposal-Facility-Based Characterization of Solid Waste in California.[182] This study estimated an overall methane capture rate of 34% from California landfills. While this is an average estimate for landfills across the state, it too strongly suggests that EPA's assumed collection efficiencies are too high. The study's result is also conservative because it is based on California landfills, which are under a more stringent regulatory regime than landfills in most or all other states and hence should be emitting at relatively lower levels.

Furthermore, by applying a single collection efficiency per cover category regardless of the actual management practices, the current regulatory approach disincentivizes operators to improve their practices to better control methane emissions. Under the current and proposed regulations, even if operators increase their methane collection by improving collection efficiency, they must report higher, not lower, emissions, as the underlying quantity of methane generated is assumed to have increased.[183]

C. Recommendations to Improve the Reporting Methodologies

In this section, we recommend several changes to the bottom-up equations to better account for the site-specific factors that impact methane generation at landfills. Specifically, we urge EPA to: 1) adjust the collection efficiency assumptions to better align with specific landfill management practices; 2) adjusting the oxidation assumptions to better account for site-specific and climatic factors; 3) remove the option to calculate and report emissions based on "back-calculation" from the quantity of methane collected; 4) collect site-level waste characterization data to improve the accuracy of methane generation estimates under HH-1; 5) improve flared emission reporting and change the default destruction efficiency factors from 99% (for onsite) and 100% (for offsite) to 95%; and 6) require advanced methane detection technologies in the reporting process as a critical check on the bottom-up equations. These changes will improve the accuracy of national and global greenhouse estimates, while also providing the site-level data necessary for effective methane mitigation efforts at landfills.

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[180] *Id.* at 342.
[181] *Id.* at 340. Similarly, anecdotal evidence from experts familiar with landfill operations indicates that in areas of the country where sand is widely available, such as in coastal regions of the Southeast, operators commonly use sand for a cover material. Sand is not effective for maintaining a vacuum, keeping out moisture, or promoting soil oxidation, all of which could decrease methane generation. Nevertheless, the regulations direct operators to apply the same collection efficiency regardless of the type of cover material used.
[182] CalRecyle's 2018 Disposal-Facility-Based Characterization of Solid Waste in California, https://www2.calrecycle.ca.gov/Publications/Download/1458.
[183] *See, e.g.*, Barlaz *supra* note 174 (raising this concern).

1. *Revise the Collection Efficiency Factors*

To address the concerns identified above regarding collection efficiency, EPA should substantially lower the assumed collection efficiency rates to better reflect the efficiencies estimated based on aerial and ground emissions measurements. EPA should use recent estimates of collection efficiencies under various cover conditions based on measured emissions to identify evidence-based efficiency factors that account for the wide range – and far lower values – of site-specific collection efficiencies.

In addition, EPA should, if possible, establish two tiers of collection efficiency factors, with the upper tier of collection efficiency factors only applicable at landfills that use some or all of a set of identified best practices, and with emissions performance confirmed through use of advanced monitoring and measurement, as discussed in below. All landfills not meeting the best practices would have to apply collection efficiency factors from the lower tier, which would specify conservative default collection efficiency rates.

The best management practices should identify the types of cover materials that are most effective. Operators should be required to report the type of material used and only allowed to apply the upper tier of collection efficiency rates if they are using soil covers with an adequate amount of clay or other fines or other cover types that have been shown to result in high collection efficiencies, as supported by peer-reviewed studies. In addition to identifying best practices for cover type, EPA should identify other types of best practices that improve methane collection efficiency and should limit application of the upper tier of collection efficiency factors to operations using some or all of these practices.

A recent report by RMI lists recommended management practices for designing and operating landfills to reduce methane emissions.[184] Design practices include: using gabion cubes on the bottom liner; maintaining vertical landfill gas (LFG) wells by installing water pumps; ensuring optimal spacing for vertical LFG wells; using well boot seals; using a vacuum box when drilling vertical LFG wells; and designing the sequence of cell filling to minimize uncompacted slopes which tend to leak more emissions.[185] Two additional practices reduce overall emissions by capturing methane sooner after waste placement: early installation of horizontal LFG wells; and installing vertical LFG wells as soon as possible while raising the wellhead as the height of the disposed waste increases.[186]

Operation and maintenance practices include: continuous dynamic adaptation and upgrading of the GCS to meet changing conditions at the landfill; minimizing the daily working face where there is no cover to impede emissions; maintaining a minimum surface grade to promote drainage; periodic analysis of waste composition, with the results used to upgrade the GCS; using a more frequent or stringent landfill gas emission monitoring schedule; and using construction and demolition waste, such as crushed concrete, to create LFG travel pathways to the collection wells.[187]

As shown in the California Air Resources Study, cover management practices have a significant effect on measured emissions. Practices that reduce emissions include: increasing the thickness of the daily cover applied and peeling it back prior to new waste emplacement to promote leachate drainage and LFG movement; maximizing the density of applied soil cover by increasing compaction of daily and intermediate cover to decrease permeability and allow higher vacuum to be applied in the GCS; minimizing the time that

[184] Ebun Ayandele et al., RMI, *Key Strategies for Mitigating Methane Emissions from Municipal Solid Waste* (July 2022), https://rmi.org/insight/mitigating-methane-emissions-from-municipal-solid-waste/.
[185] *Id.* at 47.
[186] *Id.*
[187] *Id.* at 48.

trash is exposed to the air during the peel-back of daily or intermediate cover; adding vegetative cover to the intermediate layer to increase microbial oxidation; using Posi-Shell to enhance intermediate cover performance by lowering permeability; avoiding using green waste for alternative daily or intermediate cover; installing the final cover on an ongoing basis as soon as portions of the landfill have reached their final contours; and monitoring cover integrity for damage on an ongoing basis and repairing damage as quickly as possible.[188]

Notably, EPA's Waste Reduction Model (WARM) provides temporally-weighted gas collection efficiency estimates for four different scenarios (typical, worst-case, aggressive, and a California regulatory scenario). EPA could adopt a similar, or simplified, model for the GHGRP rule, aligning each subcategory with specific operational, maintenance, and monitoring practices.

2. *Revise the Oxidation Fractions*

Due to the large uncertainty in estimation of methane oxidation, we recommend EPA use rigorous models that account for site-specific landfill cover characteristics and temporal variation in soil temperature and moisture that are verified by measured data. In the absence of rigorous models that are field verified, EPA has not yet developed a reliable estimate of methane oxidation, and we do not believe that an across-the-board application of a 10% oxidation factor (as allowed under C3 in Table HH-4 of the current regulations) is justified by the available science.

We recommend that EPA revise the reporting formulas to disallow use of a methane oxidation factor, with the exception of sites where landfill cover is specifically designed to achieve methane oxidation and the oxidation estimates are supported by onsite measurements of methane oxidation, conducted at least annually. EPA should work to identify rigorous emission estimation models that account for temporal variations in soil conditions resulting from weather to estimate methane oxidation with time. Once such models are available, EPA could revise the reporting requirements to allow or require the models' application to estimate oxidation rates, as long as this is coupled with requirements for periodic site measurements of methane oxidation to confirm that oxidation rates are remaining stable (after accounting for temperature and soil moisture). Absent these improvements, we do not believe that the science supports the use of methane oxidation factors in estimating emissions under the current or proposed regulations.

3. *Eliminate the Option to Report Emissions by Back-calculating from the Volume of Captured Methane*

The large degree of uncertainty regarding actual collection efficiencies and the likelihood that the current default collection efficiency factors are far too high makes the back-calculation method of estimating emissions inappropriate. Under equation HH-8, the assumed collection efficiencies determine the reported emissions estimates. Thus, unless and until EPA identifies highly representative collection efficiency values with low uncertainty, the reporting standards should require operators to report emissions based on the application of Equation HH-6 and should remove the option of reporting based on the application of HH-8.

4. *Require Periodic Waste Characterization Studies*

[188] *Id.* at 49.

We recommend EPA collect waste characterization data from landfills under the GHGRP, as this is a key input for methane generation estimates under HH-1. Specifically, EPA should require landfills to report waste composition data on an annual basis under the GHGRP. Operators should be required to report based on site-level waste sampling studies performed in accordance with standards specified by EPA that detail measurement techniques and frequency, such as the ASTM standards for manual sorting of truckload samples, to avoid potential mischaracterization of waste composition.

Studies suggest that many landfills and municipalities collect this information already. As discussed above, state and local greenhouse gas inventories often contain more refined waste stream data, despite the fact that the vast majority of landfills currently choose the Bulk or Modified Bulk Waste option for DOC and k values when reporting under GHGRP.[189] While there would be additional costs to standardize measurement techniques across landfills, and bring waste characterization capabilities to landfills that do not have them already, we note EPA has funding in place that can help support data collection efforts, such as under the Solid Waste Infrastructure for Recycling (SWIFR) grant program.[190]

Over the near term, we recommend EPA use the site-level waste composition data to inform more representative DOC and k values for the Bulk and Modified Bulk Waste options under subpart HH. Over the medium term, and once landfills have the necessary infrastructure in place to support ongoing waste characterization studies, EPA should phase out the Bulk and Modified Bulk options in favor of the Waste Composition option. This would improve the accuracy of bottom-up methane generation estimates under subpart HH and is also critical for monitoring progress in organics diversion efforts – a key strategy to mitigate methane emissions at landfills.

5. *Improve flared emission reporting*

We strongly support EPA's proposal to require landfills with gas collection and control systems to indicate the percentage of recovered methane that is sent to a flare or sent to a landfill gas-to-energy project in order to inform future climate and renewable energy policies. This is an important effort that will allow EPA and the public to understand and better evaluate productive uses of landfill methane, as well as the negative implications of flaring.

For landfills with gas collection and control systems, EPA already gathers information about the total volume of gas collected and whether and where it is destroyed (flared). EPA's proposal to gather additional information about the proportion of landfill gas that is flared versus sent to a landfill gas to energy project adds minimal burden to operators. This information is important to (1) help inform future policies under the Clean Air Act by providing information on the amount of recovered methane that is beneficially used in energy recovery projects, (2) help verify net methane emissions from landfills with gas collection and control systems, and (3) inform EPA, state, and local government officials on progress towards renewable energy targets and greenhouse gas emission inventories.

We support these additions and also recommend that EPA collect activity data and information about the characteristics of flares being used. Recent studies and observations have shown that flares used in the oil and gas sector commonly malfunction or are even entirely unlit, leading to significant methane emissions.[191] Given the flow and potential intermittency of gas being supplied to the flares at landfills, we suspect

[189] Jon T. Powell et al., *supra* note 165.
[190] EPA, *Solid Waste Infrastructure for Recycling Grant Program*, https://www.epa.gov/rcra/solid-waste-infrastructure-recycling-grant-program.
[191] Permian Methane Analysis Project, *Flaring: Aerial Survey Results*, https://www.permianmap.org/flaring-emissions/.

malfunctioning and unlit flares are also likely a problem in this sector. There is also significant evidence that the destruction efficiencies of flares are lower than EPA generally assumes.[192]

Understanding whether operators are using open or enclosed flares, the manufacturer-specified destruction efficiency, and any discovered malfunctions and the duration of the malfunction is important for evaluating the effectiveness of flares, their emissions, and also for informing future regulations. Assumed destruction efficiencies used in reporting equations should align with regulatory standards and the most recent data on actual destruction efficiency. Flares at landfills are not required to achieve a 99% destruction efficiency and there is little evidence of flares operating this efficiently. Better information on where gas that is sent off-site for destruction is going, and whether it is being flared, is also important for improving reporting and emission estimates.

We therefore urge EPA to collect activity data on flares and other forms of combustion devices used at landfills. Specifically, EPA should require reporters to document and report for passive and active flares:

- A unique flare ID;
- Volume of gas routed to the flare (measured by a continuous flow measurement device);
- Type of flare (open ground level, enclosed ground level, etc.);
- Maximum and minimum flow values of the flare stack (turndown-ratio);
- Whether a flare assist is present, and if so, the type of assist;
- Ignition type;
- If and how a reporter verifies that combustion is occurring; and
- Whether devices, such as temperature transmitters, are used alongside flow monitors to document the volume of emissions during periods where the flare is unlit.

Gathering information on these data elements will help EPA better understand landfill gas flaring, which can allow for future refinements to reporting calculations and inform regulatory approaches.

To align with regulatory standards and actual measurements of flare efficiency, EPA should lower the destruction efficiency assumption in equation HH-6 from 99% to 95%. Until in-situ measurements of landfill flares are conducted to better estimate emissions and destruction efficiency, EPA should base reporting on conservative estimates that it relies on in regulations and that are supported by recent scientific evidence.[193] Similarly, if gas is being sent off-site for destruction, EPA should require reporting on whether that gas is being flared, and if so, equation HH-6 should require use of 95% destruction efficiency too, not 100%.

Unifying flare reporting requirements across subparts and with regulatory standards will create more consistent estimates and allow for insights from one source category to improve performance and regulations in another. The addition of elements requiring flow measurement devices and documenting periods of unlit flares will also add some empirical verification to flare reporting, leading to more accurate reporting.

6. *Require Advanced Monitoring and Measurement Technologies*

Advanced methane detection technologies offer a promising pathway to more frequent and cost-effective methane monitoring that can serve as a critical check on the bottom-up equation estimates. In this section,

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[192] Plant et al., *Inefficient and unlit natural gas flares both emit large quantities of methane*, 377 Science 6614 (2022), https://www.science.org/doi/10.1126/science.abq0385.
[193] *Id.*; *see also* 40 C.F.R. § 60.18.

we discuss the costs and availability of advanced monitoring technologies and recommend that EPA require monitoring and reporting with these technologies for a subset of large landfills.

a) Costs and Availability of Advanced Technologies

Advanced methane monitoring technologies are already widely available and in use across the oil and gas sector, as well as by some leading landfill operators.[194] Many of these technologies are highly effective and inexpensive. And many companies providing advanced methane mitigation services are domestic and provide well-paying jobs in geographies across the country. These technologies are particularly capable and efficient at screening broad geographic areas for emissions to detect large, potentially intermittent emission sources. Layered approaches utilizing multiple techniques may be required in some cases to pinpoint sources of smaller leaks.

A recent comprehensive survey from Datu Research shows that advanced leak detection services are widely-available for the oil and gas sector. Many of these same companies and technologies can be deployed for landfills, and firms offering advanced methane monitoring are poised to scale up in coming years under the upcoming oil and gas regulations.[195] Firms offering advanced monitoring services have nearly doubled in the past four years alone and operate in regions across the country. Nearly half of firms surveyed (47%) said they could scale up significantly in the coming years; these respondents comprised those using fixed sensors, airplanes, satellites, or a combination of these technologies. Eighty-nine percent of the firms surveyed can detect emissions at the site level, while 53% can pinpoint smaller leak sources. Datu's findings underscore that advanced methane detection technologies are already widely available and could be deployed for use at landfills.

The Surface Emission Monitoring (SEM) that is currently required by federal and state regulations varies greatly in cost depending on the size of the landfill.[196] The costs for large sites scale roughly proportionately with the site's area, and costs for small sites (smaller than 50 acres) are driven by fixed costs such as mobilization, equipment and reporting rather than the size of the site. Costs can range from several thousand dollars to more than $10,000 per event.[197] The aerial monitoring techniques described below are comparable in costs, and in many cases are less expensive.

b) Overview of Advanced Technologies

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

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[194] *See, e.g.*, Waste Management, *Sustainable Technology Factsheet*, https://www.wm.com/content/dam/wm/assets/inside-wm/sustainable-technology/wm-emissions-fact-sheet.pdf; *see also* Datu Research, *Find, Measure, Fix: Jobs in the U.S. Methane Emissions Mitigation Industry* (2021), https://www.edf.org/sites/default/files/content/FindMeasureFixReport2021.pdf [hereinafter "Datu 2021"]; EPA, *Methane Detection Technology Workshops*, https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-methane-detection-technology-workshop.

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

[196] Pat Sullivan & John Henkelman, *Understanding Landfill Gas Monitoring Techniques*, Waste Today (Mar. 2019), https://www.wastetodaymagazine.com/article/landfill-gas-monitoring-techniques/.

[197] *Id.*

commercially available for leak monitoring in the oil and gas industry.[198] The use of screening technologies has grown rapidly across the oil and gas sector in the last few years.[199] Widespread adoption and deployment of emerging technologies – even in the absence of regulatory requirements – demonstrates their effectiveness and low cost and underscores the opportunity to incorporate these methods into the reporting program and future regulations for landfills.

Methane monitoring technologies can be classified in several ways. Generally, technologies can be grouped into screening (e.g., aerial) and close-range (e.g., handheld IR cameras). Most close-range methods are handheld instruments that can diagnose and pinpoint individual leaks or emission sources. Screening technologies are those that can quickly scan larger geographic areas. In some cases screening technologies may require follow-up with close-range methods. Detection capabilities vary greatly and typically increase with proximity to the emission source. However, technologies that monitor from farther away, like aircraft and satellites, are usually much faster and can cover broad geographic areas at lower cost.[200]

Comprehensive monitoring using both screening and close-range technologies is likely to be highly effective.[201] In this type of approach, screening technologies are used to monitor across broad geographic areas frequently to quickly detect the largest emission sources. Close-range methods are used for directed follow-up to pinpoint emission sources detected during screening and for routinely monitoring for emissions that would not be detected by screening methods. This type of approach may be required for adequate mitigation but not necessarily for quantifying and estimating total emissions.

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

Methane detection technologies differ not only in performance but also in the types of sources that can be identified and how these sources are characterized. For example, a recent study using aerial surveys identified far fewer – but much larger – sources than handheld surveys performed at the same time (39 vs 357 sources, respectively).[202] Many of the emissions found during the handheld survey were too small to be seen by aircraft, while many of the largest emission events occurred at a small number of locations and may have been missed during the ground inspection. This indicates that full coverage of a system is most effective with multiple technologies.[203]

When considering the performance of a monitoring approach, it is important to distinguish between technologies and methods. Technologies include deployment platforms and sensor types, while methods include the work practices and follow-up procedures after emissions are detected. Understanding the

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[198] Highwood Emission Management, *Technical Report: Leak Detection Methods for Natural Gas Gathering, Transmission, and Distribution Pipelines* (2022), https://highwoodemissions.com/pipeline-report/ [hereinafter "Highwood 2022"].

[199] *See* Highwood 2022; Datu 2021; *see also* Scientific Aviation, *Major Energy Companies Join Forces to Battle Methane Emissions* (Mar. 2021), http://www.scientificaviation.com/major-energy-companies-join-forces-to-battle-methane-emissions/.

[200] *Id.*

[201] Fox et al., *A Review of Close-range and Screening Technologies for Mitigating Fugitive Methane Emissions in Upstream Oil and Gas*, 14 Env. Res. Letters 53002 (2019), https://iopscience.iop.org/article/10.1088/1748-9326/ab0cc3.

[202] Tyner & Johnson, *Where the Methane Is—Insights from Novel Airborne LiDAR Measurements Combined with Ground Survey Data*, 55 Env. Sci. Tech. 9773 (2021), https://pubs.acs.org/doi/10.1021/acs.est.1c01572

[203] Fox et al., *supra* note 201.

methods in combination with a technology is critical when evaluating performance and overall mitigation.[204]

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

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

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

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

- **Non-methane** – Many sensors infer the presence of leaks by measuring variability in pressure, temperature, vegetation growth, physical disturbance of equipment or the areas nearby, and other proxies.[205]

Deployment platforms can be broadly classified into the following categories:

- **Aircraft[206]** – Passenger aircraft, both planes and helicopters, can be equipped with various sensor technologies and used at different elevations and frequencies. These factors, along with the methodologies used, affect survey speed and detection capabilities. Some aerial technologies or methods may use remote sensing and fly higher and faster to achieve broad coverage more rapidly. Other aerial technologies and methodologies may call for lower and slower flights or use a technology with a higher sensitivity that detects more emission events but achieves less coverage in the same time period. Aircraft detection limits range from a few kilograms of methane per hour to tens of kilograms per hour. This technology is readily available and has undergone multiple, controlled release tests to verify performance metrics. Although aircraft systems are less sensitive than other systems, some aircraft are able to cover large geographic regions. This makes it possible to survey entire landscapes for large methane sources that may not otherwise be detected by targeted, site-specific inspections. The primary limiting factors for aerial methods are weather (high winds, precipitation, cloud cover), variable reflectivity from uneven snow cover, and flight permits.

- **Unmanned Aerial Vehicles (UAVs)[207]** – Also called drones, these can reach dangerous or hard-to-reach places and can fly very close to the source of plumes. They can be equipped with IR cameras and other relatively small, lightweight sensor devices and, like aircraft, can operate in three-dimensional space. Like manned aircraft, UAVs are not restricted to

[204] *See id.*
[205] Highwood 2022.
[206] *Id.*
[207] *Id.*

roads and can complement close-range methods by reaching dangerous or inaccessible places. Some UAV systems use point measurement technologies that directly measure methane concentrations. These point measurement UAVs are often more sensitive than aircraft techniques because of their ability to fly closer to the methane source. The primary limitations for this technology are weather, the distance from the operator, and the relatively short flight times of a few hours (at most). UAVs can typically detect and pinpoint smaller emission sources. This technology is readily available and has undergone multiple controlled release tests to verify performance metrics.

- **Mobile Ground Labs (MGLs)[208]** – Consisting of a vehicle with a global positioning system and a methane sensor, MGLs enable an operator to generate a map of methane concentrations along the vehicle's path. Because it is limited to the path (usually a road), this method collects data in a two-dimensional space. Typically, MGLs will also measure environmental conditions, especially wind speed, wind direction, temperature, and humidity. MGLs can take an active or passive approach to surveying. The active approach entails MGLs driving a predetermined route along the infrastructure to be monitored, while the passive approach entails mounting sensing equipment on vehicles performing unrelated tasks, like delivery trucks.[209]

- **Continuous Monitoring[210]** – These systems are unique in that they are stationary. Fixed sensors are installed at a facility—typically in high-risk areas—to provide continuous, real-time readings of methane concentration and will trigger an alarm if concentrations exceed certain limits. Fixed and continuous monitoring technologies can be divided into active and passive categories. Active continuous monitors regularly scan an entire site or use a laser detector to monitor a large area of the site for emissions. Tower-based systems provide even greater coverage and can scan broadly from a single location. Passive continuous monitors use point sensors to monitor a single location at the site. For passive sensors to detect a leak, the emission plume must be carried via the wind to the location of the sensor; therefore, these kinds of sensors must be deployed in larger numbers.

- **Satellites[211]** – Satellites equipped to measure methane concentrations can be combined with other data to identify large sources of emissions.[212] Many methane-sensing satellites currently exist, and still more are in development. These systems are diverse in form and function; some have very high minimum detection limits and therefore are better suited to detect large plumes, while others with improved sensitivity are capable of detecting smaller sources.[213] Minimum detection limits of satellites have been estimated to be between 1,000 and 7,100 kg CH_4/hr.[214] More recently, GHGSat has claimed facility-scale detection limits as low as 100 kg/h, but these have not yet been independently verified, and other point source imagers, such as PRISMA and EnMAP, report sensitivity in the 100-1,000 kg/h range.[215]

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208 *Id.*
209 *Id.*
210 *Id.*
211 *Id.*
212 Datu 2021; Highwood 2022.
213 *See, e.g.*, EDF, *MethaneSAT*, https://www.methanesat.org/; Daniel J. Jacob et al., *Quantifying Methane Emissions from the Global Scale Down to Point Sources Using Satellite Observations of Atmospheric Methane*, 22 Atmospheric Chemistry and Phys. 14 (2022), https://acp.copernicus.org/articles/22/9617/2022/acp-22-9617-2022-assets.html.
214 Highwood 2022.
215 *Id.*

Over the past decade, there has been considerable innovation in advanced methane detection strategies. Significant advancements have occurred in technologies and deployment platforms, but also in the most effective methodologies and work practices. This innovation has largely occurred in the oil and gas production sector, but the knowledge and experimentation can be used to inform approaches to landfill methane monitoring as well.

c) Using Advanced Technologies at Landfills

Currently, most monitoring regulations for landfills require the use of Surface Emission Monitoring (SEM) on a quarterly basis.[216] SEM is a technique that involves using a portable methane meter near the landfill's surface to measure concentrations while traversing the site. Quarterly SEM is a requirement under EPA's New Source Performance Standards (NSPS) for landfills generating greater than 34 megagrams per year of non-methane organic compound (NMOC) emissions.[217] EPA requires monitoring using a serpentine pathway with 30-meter intervals. California also has quarterly SEM requirements for landfills, which require more extensive monitoring and a lower methane concentration limit. California also requires much tighter spacing of 7.6 meters (25 feet).

Methane can be emitted by a landfill both from the landfill surface and from the GCS components. Methane leaks from oil and gas facilities tend to be localized hot spots, such as components and equipment. Leaks from the landfill GCS are comparable and therefore advanced monitoring approaches used for oil and gas may transfer well to this source. Methane from the landfill surface is usually emitted in smaller quantities on an ongoing basis from a large area. While some of these emissions filter up through the cover material across the landfill, there is also a strong likelihood that much of the methane escapes through surface cracks or fissures, as well as edges, steeper slopes and areas of less compacted trash. Given the pervasiveness of these emissions, they would not necessarily contrast with the surrounding methane concentration to the same degree as would a leak from oil and gas equipment, although emissions from a crack or fissure may be larger relative to background, and so may be easier to detect. Therefore to detect and monitor these ongoing landfill surface emissions, approaches transferred from oil and gas may require modification.

The technology and techniques used in the oil and gas industry can be readily adapted in many instances for landfill GCS, but layered approaches using these technologies in conjunction with SEM may be more effective to look for and mitigate surface emissions. Handheld IR cameras could be used by landfill personnel to look for methane emissions from the GCS. However, there are some questions as to their efficacy, and aerial techniques are more commonly used. Drone-mounted IR cameras have the potential to monitor areas where personnel are not available or that cannot be safely accessed.[218] Aerial techniques, including flyovers, are already being deployed in some instances and can capture large emissions events from landfills.[219] Aerial techniques used for monitoring and quantification may not require pinpoint follow-up, although that may be necessary to locate the underlying source for mitigation.

d) Incorporating Advanced Technologies in Reporting

[216] Pat Sullivan & John Henkelman, supra note 196.

[217] 40 C.F.R. § 60.764(a)(6); 40 C.F.R. § 60.35f(a)(6).

[218] *See, e.g.*, Arlene Karidis, *Will Evolving Drones Shape Future Landfill Operations?*, Waste 360 (Sept. 28, 2022), https://www.waste360.com/landfill-operations/will-evolving-drones-shape-future-landfill-operations.

[219] *See, e.g.*, Nichola Groom, *Methane Menace: Aerial Survey Spots 'Super-emitter' Landfills*, Reuters (June 18, 2021), https://www.reuters.com/business/sustainable-business/methane-menace-aerial-survey-spots-super-emitter-landfills-2021-06-18/ (Scientific Aviation has been conducting aerial flyovers since 2016); *see also* Cusworth et al., *Strong Methane Point Sources*, *supra* note 143 (landfill emission data gathered by GAO aircraft).

Advanced methane monitoring technologies can be highly effective at locating hotspots and super-emitters at landfills–particularly aerial technologies such as flyovers, satellites, and drones.[220] This is important for improving the accuracy of emission estimates. The existing requirements for emissions estimation under subpart HH assume that GCS systems are operating normally, and the estimation methodologies do not account for emissions due to operational anomalies. Specifically, they fail to capture large quantities of emissions that may leak from the GCS system, degraded surface areas of the landfills or other sources. These leaks could be short term events, such as a blockage in a gas well that is detected and cleared, or longer term, such as emissions from surface cracks in areas with infrequent inspections. As a result, the existing estimation methodologies inherently tend to undercount emissions, as indicated by the substantially higher emissions levels measured in overflights. While we have suggested some improvements to the estimation methodologies, these suggested modifications alone are unlikely sufficient to fully capture the effect of these anomalous events (and EPA may or may not adopt our recommendations in full).

Monitoring with advanced technologies can help to correct these systemic inaccuracies in the reported emissions data. These technologies are able to catch large emission events that are not accounted for in the existing reporting requirements and can be easily missed by ground-based monitoring methods. Emissions observed using advanced methods can and should be used to supplement and improve the accuracy of estimates derived and reported under the existing framework. To effectuate this, we urge EPA to require quarterly monitoring with advanced aerial technologies at a subset of the largest landfills, as defined by EPA (e.g., based on waste acceptance rates)[221] and reporting of all detected emissions.

EPA's authority under section 114 of the Clean Air Act is broad. The section clearly authorizes EPA to require anyone who "operates any emission source" to "install, use, and maintain such monitoring equipment," "sample such emissions," and "provide such other information as the Administrator may reasonably require."[222] A monitoring requirement imposed under section 114 that is necessary to obtain accurate emissions data not otherwise currently available is reasonable. And the relatively low cost of aerial monitoring–which is typically done by contractors–further underscores the reasonableness of such a requirement. Data gathered through quarterly aerial monitoring at large landfills would be valuable for informing future landfill regulations, including monitoring requirements, and would also serve as a model for future revisions to the reporting program that rely on measurement data.[223] It should also help EPA understand how much existing regulations are driving down emissions and how operators are complying with those regulations.[224]

We urge EPA to require quarterly monitoring and emissions reporting at certain large landfills using aerial or drone-based methods with technologies that are capable of quantifying a total emission flux from the site. Emissions detected during surveys should be quantified using the best available engineering estimates

[220] *See, e.g.*, Katherine Bourzac, *Methane-monitoring Satellites Spot Landfill Superemitters*, Chemical Engineering News (Aug. 17, 2022), https://cen.acs.org/environment/greenhouse-gases/Methane-monitoring-satellites-spot-landfill/100/i29.

[221] A reasonable threshold for the subset of large landfills could be landfills accepting 1 million tons or more of waste per year. Of the 906 open landfills that reported waste acceptance rates to LMOP in 2020, 76 (~8% of the total) reported annual waste acceptance over 1 million tons, and this group accounts for about 28% of LFG generation as reported under LMOP.

[222] 42 U.S.C. § 7414(a)(1).

[223] *See id.* at § 7414(a) (setting forth the purposes for which EPA can require monitoring, which include "developing or assisting in the development of any implementation plan under section 7410 or section 7411(d) of this title, any standard of performance under section 7411 of this title, any emission standard under section 7412 of this title . . . .").

[224] *See id*.

and operational data, or otherwise quantified using a default duration, such as since the last monitoring survey occurred. Operators who conduct follow-up investigations and determine the root cause of the large emission event should be required to report that information, including whether and how it supports quantification using a shorter duration than the default. Those that do not, or who cannot determine a root cause, should be required to quantify emissions using the default duration set by EPA.

Paralleling a similar proposal for subpart W, emissions detected through quarterly aerial monitoring could be reported as a separate category of "large release events" in subpart HH. However, instead of defining a large release event by the quantity of methane released, here we urge EPA to define this category for landfills as any emissions detected and quantified during aerial monitoring. Most emissions detected by aerial technologies will be quite large, as the sensitivities of aerial technologies are generally not low enough to capture and quantify the dispersed surface emissions that are estimated through the existing or proposed reporting requirements for landfills. Thus, there is little risk of double counting emissions and a much greater risk that omitting the emissions detected by aerial technologies would make estimates less accurate overall. Nevertheless, if EPA were to conclude that a substantial proportion of the emissions detected by aerial technologies would have already been represented in the estimated emissions, EPA could maintain the aerial emissions data in a separate category that would not count toward a landfill's emission total. This would eliminate any risk of double counting but still allow EPA to gather advanced monitoring data that it could use to inform regulatory approaches and revisions to emission estimating methods. To ensure that operators do not intentionally or otherwise conduct advanced monitoring in ways that are less likely to uncover large emissions events, we recommend that EPA set forth monitoring requirements, including detection capabilities, operating parameters, and acceptable technologies.[225]

VIII. Subpart PP - Suppliers of Carbon Dioxide

We support the inclusion of direct air capture (DAC) as a CO2 capture option under subpart PP. EDF also supports the intent behind the requirement that DAC facilities report their upstream energy use. However, EDF is concerned that the proposed lifecycle analysis (LCA) reporting requirements do not take into account the full lifecycle CO2 impacts of the technology through the point of CO2 compression. Understanding the full emissions impacts of DAC systems beyond their energy use is crucial to assessing their effectiveness as carbon removal tools.

The proposed definition of DAC under 40 CFR § 98.6 may encompass a large variety of DAC technologies which utilize different materials, components, and processes to capture CO2 from ambient air. To ensure standard and consistent LCA reporting across different DAC technologies, EDF recommends that EPA adopt ISO 14040/14044 standards for DAC LCA and that EPA require suppliers to define a cradle-to-gate boundary for their DAC system. This system boundary should include all activities associated with the DAC technology, from the extraction of raw materials required to construct, maintain, and power the functional unit to the on-site compression of CO2. EDF recommends that EPA also require suppliers to report the pressure of compressed CO2 to assess consistency across DAC facilities.

The LCA requirement proposed under 40 CFR § 98.426(i) may not take into account all of the factors relevant to the CO2 impact of DAC systems within the system boundary. EDF recommends that suppliers

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[225] Many of these requirements could be aligned with, or even cross-reference, monitoring requirements for alternative leak detection and repair standards that are currently under development for EPA's oil and gas section 111 standards, OOOOb/c.

be required to report and account for CO_2 emissions from all inputs and outputs contained within the system boundary. This includes inputs such as raw materials and outputs such as co-products and waste products, in addition to on-site and off-site sourced electricity, heat and combined heat and power used to power the system. EPA should require suppliers to report the quantities of each of these inputs and outputs involved as well as the CO_2 emissions impact from each. EDF also recommends that all suppliers be required to report their data sources as well as any sensitivities or uncertainties in the data reported.[226]

IX. Subpart RR - Geologic Sequestration of Carbon Dioxide

Although EPA is not currently proposing any revisions to subpart RR, recent attention regarding the prospect of CO_2 sequestration in subsurface formations below the Outer Continental Shelf (OCS) has raised the issue of GHGRP applicability for such projects after they have been permitted by the Department of Interior (DOI). In discussions about DOI's forthcoming rulemaking, there have been mixed interpretations as to whether subpart UU remains an acceptable option for reporting for long-term storage wells on the OCS.

We believe that subpart RR applies to *any* well operating for geologic storage of CO_2, including in the offshore environment, regardless of whether the well is permitted as a Class VI well under the Safe Drinking Water Act or a different authority. This is based on:

- The absence of any exception for offshore projects in the subpart RR source category definition;
- Numerous references to modified requirements where an "offshore well is not subject to the Safe Drinking Water Act" – such as subpart RR, § 98.448(b)(2): "if your facility is an offshore facility not subject to the Safe Drinking Water Act, you must submit a proposed MRV plan to EPA within 180 days of receiving authorization to being geologic sequestration of CO_2"; and
- The definition of "surface leakage" including movement of injected CO_2 stream from the injection zone into oceans in subpart RR, § 98.449.

In order to avoid any uncertainty, EDF requests that EPA make definitively clear that any offshore facility permitted to inject CO_2 for long-term containment in a subsurface geologic formation on federal lands, including the Outer Continental Shelf, is subject to the requirements of subpart RR. Further, we recommend that EPA collaborate with DOI in their forthcoming rulemaking to ensure that this requirement is appropriately accounted for in that process.

X. Subpart VV: Geologic Sequestration of Carbon Dioxide with Enhanced Oil Recovery Using ISO 27916

A. Scope and Intent of Subpart

EDF strongly supports EPA's efforts to cure a GHGRP gap created by the Treasury's adoption of the ISO Standard (CSA/ANSI ISO 27916:2019) as a demonstration of secure storage alternative for CO_2-EOR

[226] Department of Energy, Office of Fossil Energy and Carbon Management (June 2022) - Best Practices for Life Cycle Assessment (LCA) of Direct Air Capture with Storage (DACS), https://www.energy.gov/fecm/best-practices-LCA-DACS.

operators claiming 45Q credits.[227] We also emphasize the importance of ensuring that those choosing the ISO pathway be held to a similar standard of transparency and reporting as those reporting under subpart RR. EPA should modify transparency and reporting standards as appropriate to account for the specifics of the ISO standard.

Specifically, we are concerned that vague and potentially contradictory language used in the preamble as well as the draft regulatory language may lead to misinterpretation. In particular, the draft regulatory text appears to allow operators who use the ISO pathway to demonstrate secure storage to continue using or opt to use subpart UU for GHGRP reporting. We believe this language may conflict with EPA's stated purpose in the preamble for the adoption of subpart VV, namely:

> We are proposing to add this new source category because collecting additional information from these sources would improve our knowledge on the amounts of CO2 that are geologically sequestered in association with EOR operations and allow the Agency to more comprehensively track and document the flow of CO2 through the economy to better inform EPA policy and programs under the CAA related to the use of CO2 capture and geologic sequestration.[228]

EDF recommends that EPA: 1) clarify its intent, 2) clarify the proposed regulatory text, and 3) clarify the preamble language. These recommendations are set forth in detail below.

Clarify intent: EPA should make clear in the preamble, and where appropriate in regulatory text, that *any* sequestration project obtaining tax credits or otherwise permitted or claiming to permanently store captured anthropogenic carbon dioxide must report sequestered volumes under *either* subpart RR or subpart VV, without exception. This is necessary for transparency and accuracy of the GHGRP's accounting of volumes securely sequestered. Neither subpart UU nor any other existing GHGRP subpart is acceptable for this purpose given the lack of focus on ensuring long-term secure storage.

Clarify regulatory language: The newly proposed subpart VV language appears to allow CO2-EOR projects using the ISO standard to demonstrate secure storage to continue to report under subpart UU. We believe this is unintentional, as continued allowance of subpart UU for these entities would circumvent the purpose of adopting a specialized subpart VV.

Accordingly, EDF proposes the following revisions (in red) to the proposed language defining the subpart VV source category in § 98.480:

> (a) This source category pertains to carbon dioxide (CO2) that is injected in enhanced recovery operations for oil and other hydrocarbons (CO2-EOR) ~~in which all of the following apply: (1)~~ if [y]ou are using the International Standards Organization (ISO) standard designated as CSA/ANSI ISO 27916:2019, "Carbon Dioxide Capture, Transportation and Geological Storage —Carbon Dioxide Storage Using Enhanced Oil

[227] 26 C.F.R. § 1.45Q [T.D. 9944, 86 Fed. Reg. at 4760, 2021].

[228] Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule, 87 Fed. Reg. at 36,920, page 36928 (proposed June 21, 2022) (to be codified at 40 C.F.R. Parts 9 and 98).

Recovery (CO_2-EOR)" (CSA/ANSI ISO 27916:2019) (incorporated by reference, see §98.7) as a method of quantifying geologic sequestration of CO_2 in association with EOR operations.

~~(2) You are not reporting under subpart UU of this part.~~

~~(3) You are not reporting under subpart RR of this part.~~

(b) This source category does not include wells permitted as Class VI under the Underground Injection Control program.

(c) If you are subject to only this subpart, you are not required to report under subpart RR or UU of this subpart and you are not required to report emissions under subpart C of this part or any other subpart listed in §98.2(a)(1) or (a)(2).

Also, in § 98.483, calculating CO_2 geologic sequestration, (d) should read:

> (d) You must calculate the total mass of CO_2 loss from project operations (mloss operations) in the reporting year as specified in Equation VV-2 of this section.

Clarify preamble text: In order to remove ambiguity in the preamble, EDF proposes these edits to the following language at 87 Fed. Reg. 36,936:

> The facilities affected by the proposed subpart include facilities that are currently reporting under subpart UU and that do not currently report amounts of CO_2 sequestered. The EPA is proposing no threshold for the proposed subpart VV so that all EOR facilities that quantify CO_2 sequestration using the CSA/ANSI ISO 27916:2019 standard ~~and that do not report under subpart RR would have the option to either~~ report under the proposed subpart VV~~, or would otherwise continue to report under subpart UU~~. For these reasons, we do not anticipate that the new subpart would increase the number of facilities subject to the GHGRP. ~~Further, it is difficult to predict how many injection facilities would choose to report using the ISO standard in lieu of continuing to report under subpart UU.~~

B. Transparency and Public Reporting

The most significant difference between subpart RR and CSA/ANSI ISO 27916:2019 is related to public transparency. EPA publishes final decisions under subpart RR on its website, such as whether to approve an MRV plan or request for discontinued reporting. Any interested person can appeal subpart RR final decisions to EPA's Environmental Appeals Board. In addition, EPA also verifies the data submitted in annual GHGRP reports, including annual monitoring reports submitted under subpart RR, and publishes non-confidential data on the EPA website. In contrast, facilities that follow CSA/ANSI ISO 27916:2019 are not currently subject to requirements related to public reporting and transparency of amounts stored and associated documentation. The ISO standard itself, as relied on by the Internal Revenue Service, does not contain the requirements for public disclosure and transparency of information necessary to allow the public to review the adequacy of the demonstration of secure geological storage.

With these factors in mind, EDF generally supports EPA's proposal to require reporting and documentation in subpart VV that aligns with the documentation envisioned in the ISO standard. This would provide transparent information to EPA and the public to track the value chain of CO_2 supply and disposition.

C. Additional Request for Comment on CO_2 Utilization

We recommend that EPA undertake further research and development on utilization and the ability to demonstrate long-term secure sequestration utilizing reliable, repeatable, and verifiable MRV plans. Without that information, it would be difficult to develop a new subpart. EDF recognizes EPA's intent and challenge in considering when and how to incorporate the potentially growing field of CO_2 utilization in the GHGRP. However, because science, data, and other basic information on the utilization industry broadly is limited at this time – including potentially substantive gaps in monitoring, reporting, and verification plans and capabilities for these projects – it is not clear to us that the time is right to establish a new source category.

XI. Energy Consumption[229]

We urge EPA to collect data on energy consumption to enable better understanding of sectors' indirect emissions and decarbonization potential. EPA requests comment on future revisions to the GHGRP that would add requirements related to energy consumption.[230] These revisions could provide both "information on industrial sectors where currently little data is reported to GHGRP" and "a means for the EPA to better estimate and understand U.S. GHG emissions and trends that could inform future policies."[231] We support these goals and urge EPA to take a broad approach. Specifically, within each category covered by part 98, EPA should require owners and operators of facilities that already report emissions under the GHGRP and of facilities of comparable size and function (in terms of capacity to consume energy and/or total energy input) to report the quantities and attributes of the electricity and other energy that they purchase.

Clean Air Act section 114 grants broad authority to EPA to require "any person . . . who the Administrator believes may have information necessary for the purposes set forth in this subsection" to "establish and maintain such records," "make such reports," and "provide such other information as the Administrator may reasonably require."[232] Those requirements are not limited to owners and operators of emission sources.[233] Further, the purposes of the subsection include, among other things, "developing or assisting in the development of any implementation plan under section . . . 111(d) [or] any standard of performance under section 111."[234] Thus, by its terms, section 114 authorizes EPA to require reporting of information by owners and operators of non-sources, such as electrified equipment, if that information would advance new source performance standards or emission guidelines for existing sources under section 111.

Information on the quantities and attributes of energy consumption, including electricity purchases, for facilities across all industrial subsectors is essential to evaluating greenhouse gas mitigation strategies for those subsectors. For example, as EPA has noted in the prior rulemaking, data on energy consumption could reveal potential emission reduction opportunities from implementing energy-efficiency measures.[235] In addition, this information could improve EPA's and other stakeholders' understanding of the degree to which an industrial subsector has already electrified; the amounts of electricity required for equipment of

[229] Our comments on Energy Consumption were developed through joint collaboration with the Clean Air Task Force and contain similar recommendations.
[230] 87 Fed. Reg. at 37,016.
[231] *Id.* at 37,017.
[232] 42 U.S.C. § 7414(a)(1).
[233] *See id.*
[234] *Id.* at § 7414(a).
[235] 74 Fed. Reg. at 56,260, 56,289 (Oct. 30, 2009).

different sizes, applications, and geographic locations; the qualities of the electricity purchased, such as the market type and renewable attributes; and the potential reduction in direct and indirect emissions from electrifying or from timing electricity use to hours in which overall demand is low. In turn, the information could shape EPA's analysis of the feasibility, cost, and efficacy of reducing emissions through electrification in various subsectors, as well as the impacts of the incidental electrification that results when sources comply with regulatory requirements premised on other control techniques.

A. Collect Energy Consumption Data from Reporting Facilities and Facilities of Comparable Size and Function

In the present notice, EPA seeks comment on the scope of potential additional requirements to report data on energy consumption, and specifically whether reporting requirements should be limited to those entities already currently subject to the GHGRP, or expanded to other operators in discrete subsectors that meet all their energy needs with purchased power that may not trigger applicability under the GHGRP.[236]

We recommend the broader approach: requiring reporting on energy consumption (including electricity purchases) from currently covered GHGRP facilities, as well as industrial facilities and operations that are not currently covered because they meet all or some of their energy needs with purchased power. Further, to avoid confusion, we recommend that EPA add these requirements to the general provision governing reporting by all facilities,[237] rather than creating a separate source category for energy consumption.[238]

To set thresholds for inclusion of facilities not already reporting emissions under the GHGRP, EPA could specify the total level of energy input over a certain timeframe and/or the total capacity that would identify facilities roughly equivalent in size and function to facilities utilizing combustion-powered equipment otherwise required to report under the GHGRP. Specifically, for a facility with a source category that is listed in Table A-4 to subpart A and that is not already required to report emissions, EPA could establish a threshold to report energy consumption and energy attributes from each of its energy purchases, with the threshold being equivalent to the minimum total energy input of any facility containing the same source category that is currently reporting under 40 C.F.R. § 98.2(a)(2) because it directly emits 25,000 metric tons or more of CO_2 equivalent from process emissions and the combustion of natural gas.[239] Facilities above this threshold would be required to report energy consumption and energy attributes from each of their energy purchases, as would any facility that is already reporting emissions. This approach is reasonable as it would not require burdensome new reporting for small facilities. It would allow EPA and potentially other stakeholders to analyze energy consumption from these facilities but avoid requiring the facilities to estimate indirect emissions, which could prove to be a complicated and unreliable metric for inclusion.

For any facility that does not contain a source category listed in either Table A-3 or Table A-4 to subpart A and that is not already required to report emissions, EPA could establish a two-part threshold to report energy consumption and energy attributes from each of its energy purchases. This threshold would be equivalent to: 1) the minimum total energy input of any facility that is currently reporting under 40 C.F.R. § 98.2(a)(3) because it directly emits 25,000 metric tons or more of CO_2 equivalent from process emissions and the combustion of natural gas; and 2) 30 MMBtu/hr of total capacity of energy-consuming equipment, consistent with 40 C.F.R. § 98.2(a)(3)(ii). Both components of the threshold would need to be met to trigger

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[236] 87 Fed. Reg. at 37,018.
[237] *See* 40 C.F.R. § 98.3(c)(4).
[238] The requirements should not be limited to facilities containing sources from any "applicable source category," as the term is defined in 40 C.F.R. § 98.3(c)(4)(viii).
[239] EPA could list these source-category-specific thresholds in Table A-4.

reporting requirements for a facility that does not contain a source category listed in either Table A-3 or Table A-4 to subpart A and is not already required to report emissions.

All facilities that would be included under this framework would be required to report data on electricity and other energy purchases—whether those facilities are fully electrified or rely primarily on combustion or other energy purchases as energy sources. The additional reporting requirements would be reasonable in part because the reporting thresholds would be designed to limit applicability to facilities that are already reporting under the GHGRP or are comparable in size and function to such facilities. The required data elements themselves should be readily available in company records because energy or electricity purchases involve documented transactions.[240] Accordingly, the additional requirements would be reasonable, and therefore authorized under section 114.

B. Reporters Should Distinguish Between Thermal Energy and Electricity, and Should Include Information on Associated Energy Attribute Certificates

EPA additionally asks whether reporting on energy consumption "should include purchased thermal energy products, and whether or not associated reporting requirements should differentiate purchased thermal energy products from purchased electricity."[241] At minimum, the reporting requirements should distinguish purchased electricity from purchased thermal energy products, to provide useful information on the quantity and quality of electricity that reporting entities secure. Nonetheless, we urge EPA to require reporting of all purchased energy; in evaluating the emissions advantages of energy efficiency measures, electrification, and other greenhouse gas abatement techniques, it will be important to account for indirect emissions from all forms of purchased energy, across all facilities that are required to report going forward.

Regarding the attributes of electricity purchases, EPA suggests that relevant information could include "summary data elements . . . characterizing associated markets and products (e.g., regulated or deregulated electricity markets and renewable attributes of purchased products)."[242] These data elements would likely prove useful in estimating indirect emissions associated with electricity purchases. In addition, EPA should ensure that more-detailed data are also reported, such as the eGRID subregion in which, and the entity from which, the facility purchases electricity. EPA should also consider requiring sources to report the full range of data in energy attribute certificates, including novel elements such as storage-related tags, hourly or sub-hourly timestamps, grid carbon-intensity snapshots, and social or community benefit credentials.[243] These more-granular, readily reported data would enable EPA to evaluate the success that various industrial subsectors or companies have found in procuring carbon-free electricity that promotes emerging technologies and benefits underserved communities.

Finally, if concerns about disclosure of confidential business information from reporting the quantities and attributes of purchased electricity and other forms of energy were to arise, EPA could address those issues in a later rulemaking, consistent with the agency's past practice.[244] It will be important to ensure that EPA's

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[240] *Cf.* 74 Fed. Reg. at 16,448, 16,480 (Apr. 10, 2009) (proposed GHG Reporting Rule, noting that facilities would be expected to retain these data on electricity purchases as part of routine financial records).
[241] 87 Fed. Reg. at 37,018.
[242] *Id.*
[243] *See* Doug Miller, Clean Energy Buyers Ass'n, *Energy Attribute Certificate Issuing Bodies Can Unleash Next Generation Procurement by Capturing More Attributes & Better Serving as a "Platform of Platforms"* (June 30, 2022), https://cebuyers.org/blog/energy-attribute-certificate-issuing-bodies-can-unleash-next-generation-procurement-by-capturing-more-attributes-better-serving-as-a-platform-of-platforms/.
[244] *See* 74 Fed. Reg. at 56,289 (indicating that EPA would determine, in a subsequent rulemaking, whether data on electricity purchases could be withheld from publication as confidential business information).

reporting requirements do not discourage entities’ efforts to improve energy efficiency or transition to fully electrified processes.

Thank you for your consideration of these comments.

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