October 6, 2022

U.S. Environmental Protection Agency
EPA Docket Center,
WJC West Building, Room 3334,
1301 Constitution Avenue NW,
Washington, DC 20004

Submitted via the Federal eRulemaking Portal at https://www.regulations.gov

Re: Comments of Clean Air Task Force on Revisions and Confidentiality Determination for Data Elements Under the Greenhouse Gas Reporting Rule, Docket ID No. EPA–HQ–OAR–2019–0424, 87 Fed. Reg. 36920

Clean Air Task Force ("CATF") respectfully submits the following comments regarding the Environmental Protection Agency's ("EPA") proposed updates to the Greenhouse Gas Reporting Program ("GHGRP"). CATF is a global nonprofit organization working to safeguard against the worst impacts of climate change by catalyzing the rapid development and deployment of low-carbon energy and other climate-protecting technologies. With 25 years of internationally recognized expertise on climate policy and a fierce commitment to exploring all potential solutions, CATF is a pragmatic, non-ideological advocacy group with the bold ideas needed to address climate change. CATF has offices in Boston, Washington D.C., and Brussels, with staff working virtually around the world.

Improvements to GHGRP data are critical to helping inform future Clean Air Act rules and to understanding potential decarbonization pathways. We commend EPA for taking these important steps to improve the quality of this data.

I. Subpart C[1]

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. 87 Fed. Reg. at 36939. 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 the typical operating-temperature range and output type (*i.e.*, water, steam, or other) of each unit.

[1] Our comments on subpart C were developed in collaboration with Environmental Defense Fund and contain similar recommendations.

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." *Id.* EPA already requires owners and operators using the individual unit configuration to report unit type and maximum rated heat input. *See* 40 C.F.R. § 98.36(b)(2), (3). "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." 87 Fed. Reg. at 36939. 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." *Id.*

We agree that unit-specific data is key to understanding not only the distribution of emissions across unit types and sizes, but also the GHG 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 CAA section 111. Developing NSPS and emission guidelines are among the purposes expressly mentioned in CAA section 114, which broadly authorizes EPA to adopt reporting requirements that would facilitate the agency's implementation of the Act.[2]

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 from the GHGRP,[3] 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:

[2] 42 U.S.C. § 7414(a)(1).

[3] Colin McMillan, Nat'l Renewable Energy Lab., *Industrial Facility Combustion Energy Use* (2016), https://data.nrel.gov/submissions/50.

Table 1

Subsector	Total CO_2 Emissions (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. 87 Fed. Reg. at 36939. 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. *See id.* 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, *id.*—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 GHG 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. *See id.* (seeking comment on this topic).

B. EPA should lower the capacity threshold for reporting the characteristics of individual stationary combustion units

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. 87 Fed. Reg. at 36939-40. The share of total annual heat input should be available in company records. *See id.* at 36940. And none of the requirements to report individual unit characteristics would sweep in facilities that are not already subject to the GHG Reporting Rule, based primarily on the facility's subcategory and emissions. *See* 40 C.F.R. § 98.2(a). This requirement will add little burden to reporters while providing EPA and stakeholders with important information.

On the other hand, EPA should consider lowering the size threshold for reporting unit characteristics below 10 MMBtu/hr, which EPA has proposed to retain. 87 Fed. Reg. at 36939. This is a reasonable reporting requirement because the full set of data on individual stationary combustion sources is crucial to assessing GHG 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.[4] In the case of industrial boilers, although these smaller boilers do not account for a large share of total capacity,[5] they often present the most viable opportunities for GHG emissions abatement including through electrification with heat pump technology.[6] 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.[7] 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." 81 Fed. Reg. 89188, 89204 (Dec. 9, 2016). The present objective, however, is not to check emissions data against aggregate capacity, which can be accomplished even while disregarding emissions from smaller sources. *See id.* at 89203. Rather, it is to evaluate GHG 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 GHG emissions from combustion sources mean EPA should lower or eliminate the threshold to report unit characteristics.

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, *see* 42 U.S.C. § 7411(d)(1). 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.

---

[4] *See* Carrie Shoeneberger et al., *Electrification potential of U.S. industrial boilers and assessment of the GHG emissions impact*, 5 Advances 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.

[5] *See id.*

[6] *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.

[7] *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.

We recommend that the agency 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.[8] 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.[9] 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 CAA section 114.[10]

D. EPA should collect data that would allow the agency to ascertain the concentration of CO_2 in each flue gas stream exiting a stationary combustion unit

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, 40 C.F.R. § 98.33(a)(4)(ii), *id.* § 98.36(c)(2), 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 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 H: EPA should collect data regarding relative amounts of fuels combusted in cement kilns

EPA proposes to collect annual averages of chemical composition inputs of calcium and magnesium oxides for cement kilns covered by Subpart H. 87 Fed. Reg. at 36943. While this is a desirable change, there is also a need for more information on kiln fuel inputs. Current data does not include the amounts of fuel input into cement kilns. However, such information is important

[8] *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.

[9] *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.

[10] 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.

for understanding the expected kiln flue gas composition, which in turn is necessary for evaluating options to decarbonize the cement sector.

III. Subpart W[11]

A. MERP Congressional Directive

Under the recently passed Inflation Reduction Act, Congress established the Methane Emissions Reduction Program (MERP) under the Clean Air Act.[12] One important charge to EPA in MERP is the requirement to:

> revise the requirements of subpart W . . . to ensure the reporting under such subpart . . . are based on *empirical data* . . ., *accurately reflect* total methane emissions and waste emissions from the applicable facilities and allow owners and operators of applicable facilities to submit empirical emissions data…[13]

As discussed more fully below, there are limitations to EPA's existing emission factors used to estimate methane emissions in Subpart W. Such limitations mean that the methane emission estimates are neither accurate nor empirically-based.[14] Thus, any finalized updates flowing from this proposal do not, and cannot, satisfy EPA's obligation to revise Subpart W as required under MERP. EPA should clearly state as much in its finalization of this rulemaking.

B. The Significant Problem of Underestimation

Emission estimates derived from data reported through the GHGRP have traditionally been inaccurate and lead to significant underestimation of total emissions from the oil and gas sector, with the greatest divergence in the production segment.[15] A large body of peer-reviewed literature has documented this problem over the past decade, primarily attributing the divergence to the GHGRP and GHGI's 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 fat-tailed emission distribution, where the top 5-10% of sites or components are responsible for around 50% of total emissions. Below, we

---

[11] Our comments on subpart W were developed in collaboration with the Environmental Defense Fund and contain similar recommendations.

[12] Inflation Reduction Act of 2022, Pub. L. No. 117-169, § 60113 (to be codified at 42 U.S.C. § 7436(h)).

[13] *Id.* § 60113(h).

[14] Because "empirical data" is undefined in MERP, the term takes its ordinary meaning, informed by the statutory context. *Kouichi Taniguchi v. Kan Pac. Saipan, Ltd.*, 566 US 560, 566 (2012). "Empirical" means "originating in or based on observation or experience" and "capable of being verified or disproved by observation or experiment." Merriam-Webster, *Definition of Empirical*, https://www.merriam-webster.com/dictionary/empirical.The long-standing and well-documented inaccuracies of subpart W clearly establish that the current methodologies to report methane emissions under Subpart W do not meet this definition, especially under the statutory context of requiring accurate methane emissions.

[15] *See, e.g.*, Ramón A. 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; Jeffrey S. Rutherford et al., *Closing the methane gap in US oil and natural gas production emissions inventories*, 12 Nature Commc'ns 4715 (2021), https://www.nature.com/articles/s41467-021-25017-4.

summarize the literature documenting this type of emissions, which characterizes 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 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).[16] Fugitive emissions can also result from devices that vent as part of normal operations, such as natural-gas driven pneumatic controllers, and control devices or equipment combusting natural gas, like flares, when those devices are not operating as intended and have abnormally high emission rates. Fugitive emissions that result from abnormal operating conditions or equipment failures and result in large emission events are often termed "super-emitters."

Super-emitters are often not well-represented (and may not be represented at all) in official inventories because they can be intermittent and are easily missed when taking equipment- or component-level measurements.[17] Because of this, emission factors derived from such measurements that do not otherwise account for super-emitters are not representative of 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, fat-tailed emission distribution means that 5-10% of sites are often responsible for 50% or more of total emissions.

Over the last decade, research by EDF and others has quantified the significance of methane emissions caused by oil and gas production and the persistent underestimation of fugitive and abnormal process emissions.[18] A large body of measurement-based studies have consistently

---

[16] Daniel Zavala-Araiza et al., *Toward a Function Definition of Methane Super-Emitters: Application to Natural Gas Production Sites*, 49 Env't Sci. Tech. 8167 (2015), https://pubs.acs.org/doi/pdf/10.1021/acs.est.5b00133.
[17] *See* IEA, *Methane Tracker Database* (October 2021), https://www.iea.org/articles/methane-tracker-database (summary of inventory estimates).
[18] EDF, *Methane research series: 16 studies*, https://www.edf.org/climate/methane-research-series-16-studies (last visited Oct. 6, 2022).

found higher oil and gas methane emissions than is reflected in EPA inventories.[19] 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.[20] Accounting for these emission events can increase inventory estimates by 60-70%, underscoring the importance of accurate reporting protocols that capture such emissions.[21]

---

[19] David R. Lyon et al., *Constructing a spatially resolved methane emission inventory for the Barnett Shale region*, 49 Env't Sci. Tech. 8147 (2015), https://pubs.acs.org/doi/full/10.1021/es506359c; Daniel Zavala-Araiza et al., *Reconciling divergent estimates of oil and gas methane emissions*, 112 Proc. Nat'l Acad. Sci. 15597 (2015), https://www.pnas.org/doi/abs/10.1073/pnas.1522126112; Daniel Zavala-Araiza et al., *Super-emitters in natural gas infrastructure are caused by abnormal process conditions*, 8 Nat'l Commn's. 14012 (2017) [hereinafter Zavala-Araiza et al., *Super-emmiters*], https://www.nature.com/articles/ncomms14012; Daniel J. Zimmerle et al., *Methane emissions from the natural gas transmission and storage system in the United States*, 49 Env't Sci. Tech. 9374 (2015), https://pubs.acs.org/doi/10.1021/acs.est.5b01669; Mark Omara et al., *Methane emissions from conventional and unconventional natural gas production sites in the Marcellus Shale region*, 50 Env't Sci. Tech. 2099 (2016) [hereinafter Omara et al., *Marcellus Shale*], https://pubs.acs.org/doi/10.1021/acs.est.5b05503; Jeff Peischl et al., *Quantifying atmospheric methane emissions from Haynesville, Fayetteville, and northeastern Marcellus shale gas production regions*, 120 J. Geo. Res. Atmospheres 2119 (2015), https://agupubs.onlinelibrary.wiley.com/doi/full/10.1002/2014JD022697; Dana R. Caulton et al., *Importance of superemitter natural gas well pads in the Marcellus Shale*, 53 Env't Sci. Tech. 4747 (2019), https://pubs.acs.org/doi/10.1021/acs.est.8b06965; Anna M. Robertson et al., *New Mexico Permian Basin measured well pad methane emissions are a factor of 5—9 times higher than U.S. EPA estimates*, 54 Env't Sci. Tech. 13926(2020), https://pubs.acs.org/doi/abs/10.1021/acs.est.0c02927; Yuzhong Zhang et al., *Quantifying methane emissions from the largest oil-producing basin in the United States from space*, 6 Sci. Advances 5120 (2020), https://advances.sciencemag.org/content/6/17/eaaz5120/tab-pdf; David R. Lyon et al., *Concurrent variation in oil and gas methane emissions and oil price during the COVID-19 pandemic*, 21 Atmos. Chem. Phys. 6605 (2021) [hereinafter Lyon et al., *Concurrent variation*] https://acp.copernicus.org/articles/21/6605/2021/acp-21-6605-2021.html.

[20] Rutherford et al., *supra*, note 15.

[21] Alvarez, *supra*, note 15.

Emissions:

Total Emissions (Metric tons methane):	16,284,709
Formatted Total Emissions with Uncertainty (Million metric tons methane):	16 +/- 2
Methane Leak Rate (based on gross production):	2.4%
Methane Leak Rate (based on marketed production):	2.7%
Total VOC Emissions (Metric tons):	5,127,475

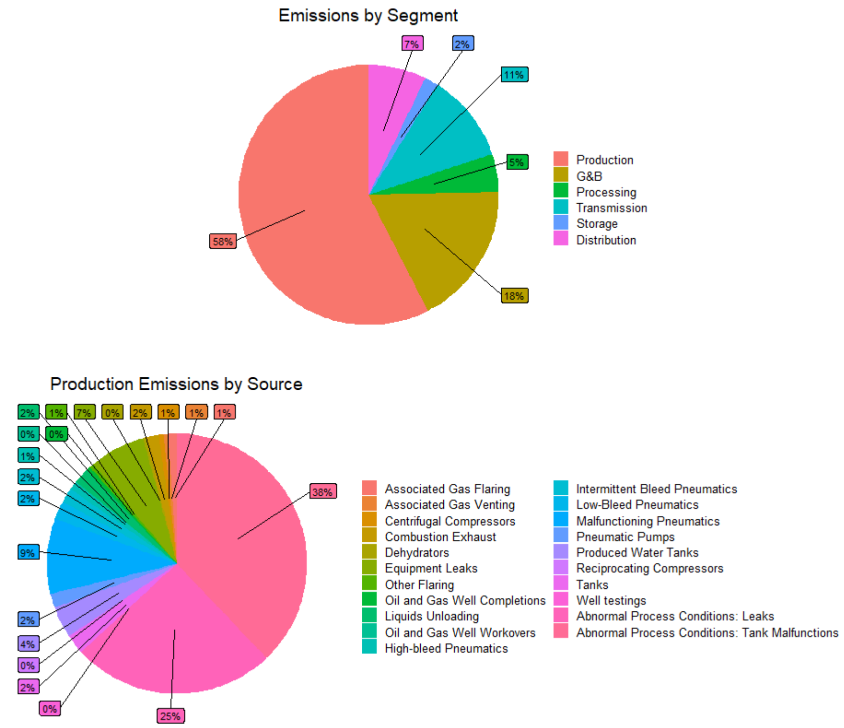

Figure 1. Alvarez Synthesis Model Inventory Estimates (2019).[22]

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.[23] 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.[24] Numerous other studies have confirmed that bottom-up approaches like the GHGI and the Subpart W reporting protocols greatly underestimate oil and gas methane

[22] For an explanation of the methodology used to create this inventory, *see* EDF, *2019 U.S. Oil & Gas Methane Emissions Estimate* (2020), http://blogs.edf.org/energyexchange/files/2021/04/2019-EDF-CH4-Estimate.pdf.
[23] *See* Environmental Defense Fund, *Methane research series: 16 studies*, https://www.edf.org/climate/methane-research-series-16-studies.
[24] Alvarez, *supra*, note 15.

emissions, largely capturing only component-level leaks and often missing the largest emission events.[25]

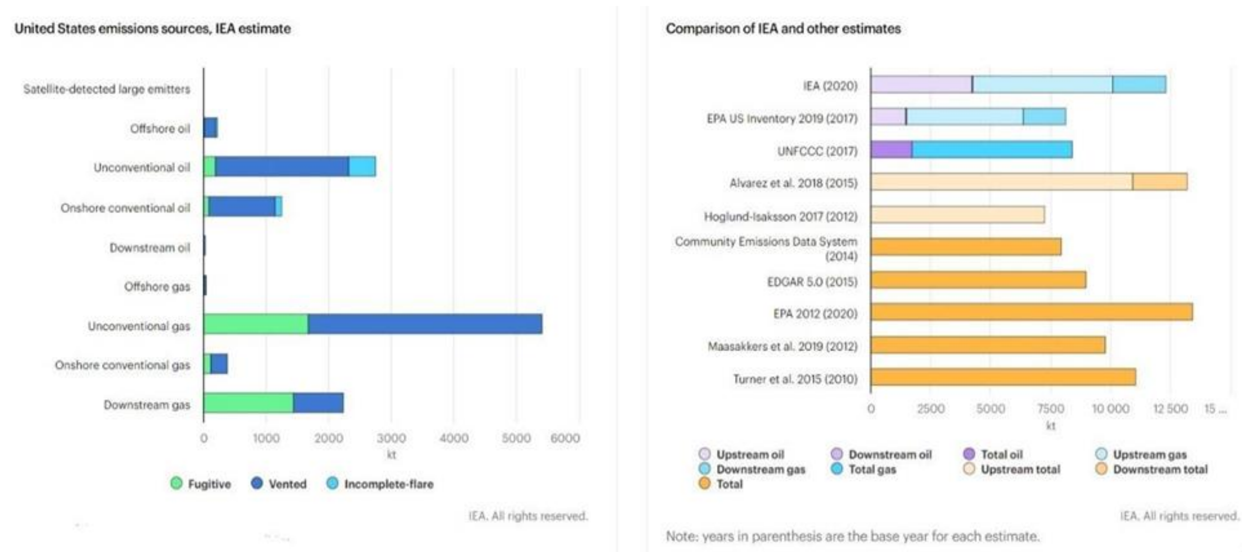

Figure 2. IEA Comparison of Emission Inventory Estimates.[1]

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 for 2019, derived from the Alvarez synthesis model and using more recent activity data,[26] 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.[27] Third, low production or marginal wells tend to have lower absolute emissions than high production wells, but much higher loss rates as a percentage of gas production. And because roughly three quarters of all wells are marginal, they cumulatively contribute a substantial fraction of total emissions–up to 50% of production sector emissions according to a recent study.[28] 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

---

[25] *See*, *e.g.*, Rutherford et al., *supra* note 15.
[26] EDF, *2019 U.S. Oil & Gas Methane Emissions Estimate*, http://blogs.edf.org/energyexchange/files/2021/04/2019-EDF-CH4-Estimate.pdf.
[27] David R. Lyon, et al., *Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites*, 50 Env't Sci. Tech. 4877 (2016) [hereinafter Lyon et al., *Aerial Surveys*] https://doi.org/10.1021/acs.est.6b00705.
[28] Omara et al., *Marcellus Shale*, *supra* note 19; see also Environmental Defense Fund, *Marginal Well Factsheet* (2021), https://www.edf.org/sites/default/files/documents/MarginalWellFactsheet2021_0.pdf.

nation's largest oil field, and then posts the emissions data on the public website PermianMAP.org to facilitate mitigation. This project and the associated studies have generated several important findings, which we briefly summarize here.

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.[29] In 2021, Lyon et al. found a similar loss rate of 3.3% in the core production area of the Delaware sub-basin in March 2020 using aircraft and tower-based measurements. The paper reports that the loss rate temporarily dropped to 1.9% in April 2020 when oil prices declined but recovered to prior levels by summer 2020.[30] The authors hypothesize that the Permian Basin typically has a high loss rate because wells are developed faster than the pipelines and compressor stations needed to transport the gas to market. This leads to both high rates of associated gas flaring and abnormal emissions due to gathering systems with inadequate capacity. 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 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.[31] Finally, Cusworth et al. in 2021 used an aerial remote sensing approach to quantify over 1,100 large methane sources in the Permian.[32] 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.[33] 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

---

[29] Zhang et al., *supra* note 19.
[30] Lyon et al., *Concurrent variation*, *supra*, note 19.
[31] Robertson et al., *supra* note 19.
[32] Daniel Cusworth et al., *Intermittency of Large Methane Emitters in the Permian Basin*, 8 Env't. Sci. Tech. Letters 567 (2021), https://pubs.acs.org/doi/abs/10.1021/acs.estlett.1c00173.
[33] Environmental Defense Fund, Permian Methane Analysis Project, https://data.permianmap.org/pages/operators (November 2021 Flyover Results).

of thousands of these sites nationwide, the cumulative emissions are very problematic and represent more than half of total production-segment emissions.[34] 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.[35] 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.[36] For the very low production category of 0-1 BOE/day wells, which contribute just 0.2% and 0.4% of national oil and gas production, respectively, research in the Appalachian Basin estimated that wellhead methane emissions account for 11% of the production-related methane emissions in the EPA's inventory.[37] The same research observed that many marginal wells emit as much or more gas than they reported producing—in a region where natural gas is the primary product operators are aiming to sell.

The scientific understanding of oil and gas methane emissions has expanded greatly over the last decade and can inform 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.

C. 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. However, we suggest that EPA adopt 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, and we expect it will continue and 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 concerned that oil and gas mergers and acquisitions in the oil and gas sector may undermine emissions reduction efforts. If assets move from industry leaders on the energy transition to industry laggards, emissions could increase and transparency

[34] Mark Omara et al., Methane emissions from US low production oil and natural gas well sites, 13 Nature Commc'ns 2085 (2022) [hereinafter Omara et al., *gas well cites*], https://doi.org/10.1038/s41467-022-29709-3.
[35] Stuart N. Riddick et al., *Measuring methane emissions from abandoned and active oil and gas wells in West Virginia*, 651 Sci. Total Env't 1849 (2019), https://doi.org/10.1016/j.scitotenv.2018.10.082.
[36] Omara et al., *Marcellus Shale*, *supra* note 19.
[37] Jacob 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.

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 an increasingly mainstream topic across the environmental community, 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.[38] 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, 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 every year during this period public-to-private transfers comprised the largest share of deals.
- **Assets are increasingly moving away from companies with environmental commitments**.[39] 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, and below we briefly summarize the proposed changes and then recommend improvements.

EPA proposed changes applicable to four categories of ownership transfer:

[38] Environmental Defense Fund, *Transferred Emissions: How Risks in Oil and Gas M&A Could Hamper the Energy Transition* (2022), https://business.edf.org/insights/transferred-emissions-risks-in-oil-gas-ma-could-hamper-the-energy-transition.
[39] 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.

1) When the entire facility is sold to a single purchaser and the purchasing owner or operator does not already report to the GHGRP in that industry segment, then purchasing owner or operator 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 purchasing owner or operator already reports to the GHGRP in that industry segment (and basin or state, as applicable), then the purchasing owner or operator 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 the seller's facility to one or more purchasing owners or operators, then the selling owner or operator would continue to report for the retained emission sources unless and until that facility meets one of the criteria in 40 CFR 98.2(i) and complies with those provisions.
4) When the selling owner or operator does not retain any of the emission sources and sells all of the facility's emission sources to more than one purchasing owner or operator, then the selling owner or operator would notify the EPA within 90 days of the transaction and the purchasing owners or operators would either begin reporting their acquired applicable emission sources as a new facility or add the acquired applicable emission sources to their existing facility.

These proposed changes, and EPA's prior interpretation of reporting requirements in cases of ownership transfer,[40] 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. This type of transaction is the most concerning because it is likely to lead to unreported emissions and gaming of otherwise applicable requirements.

We recommend that EPA clarify that when a transaction causes a facility to fall below the reporting threshold, the seller must continue reporting until the conditions in 40 CFR 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 CFR 98.2(i)(1)-(2). We also urge EPA to clarify that 40 CFR 98.2(i)(3) only applies when the operations entirely cease to operate, not only when they cease to be operated by the seller. Finally, EPA should require owners and operators to notify EPA when transactions occur and should track these transactions. New regulatory requirements, corporate environmental commitments, and the methane waste charge could drive strategic asset transfers to avoid otherwise applicable requirements, and that EPA should track and publicly disclose these transactions.

[40] United States Environmental Protection Agency, *Q749. What are the notification requirements when an Onshore Petroleum and Natural Gas Production facility, reporting under Subpart W, sells wells and associated equipment in a basin?* (last updated Sept. 26, 2019), https://ccdsupport.com/confluence/pages/viewpage.action?pageId=198705183.

D. Large Release Events

We support EPA's proposal to include a new emissions source for large release events of at least 250 $mtCO_2e$ per event or approximately 500,000 scf of pipeline quality natural gas, but we urge EPA to set a lower threshold that captures a greater number of such events. If EPA does not lower the threshold to account for such events, it must account for those emissions through other aspects of the reporting program, such as through statistical incorporation in the leaker emission factors.

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)[41] and the Aliso Canyon leak (109,000 tons of methane).[42] 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 significantly contribute to the source category's total emissions–by our estimate, representing 63% of the total in the production segment alone.[43] 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 inventory estimates and EPA's. For reporting to be accurate and serve as the basis for accurate inventory 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 10 kg/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 10 kg/hr or greater would go undetected for this length of time and exceed the threshold already proposed by EPA. Requiring leaks with detected emission rates greater than 10 kg/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

[41] 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 Pandey 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.
[42] 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.
[43] *See supra* Figure 1. For an explanation of the methodology used to create this inventory, *see* Environmental Defense Fund, *2019 U.S. Oil & Gas Methane Emissions Estimate* (2020), http://blogs.edf.org/energyexchange/files/2021/04/2019-EDF-CH4-Estimate.pdf.

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 leak detection and repair (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.

E. Alignment with OOOOb & OOOOc

We support EPA's efforts to align Subpart W with forthcoming regulatory requirements and in this section provide recommendations for further alignment. A significant portion of Subpart W reporting facilities and emission sources will become subject to LDAR requirements under OOOOb and OOOOc in the coming years. We therefore support EPA's proposal to require these facilities to report data gathered through monitoring surveys, and the option to do so voluntarily for facilities or portions of facilities not subject to fugitive monitoring regulatory requirements. Because these facilities and sources will already be required to monitor for LDAR compliance, reporting data gathered through monitoring surveys through Subpart W poses very little additional burden. EPA should additionally require for larger leaks that duration 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.

We also support EPA's proposal to expand the current reporting requirement in 40 CFR 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 CFR 98.233(q) were conducted to comply with the fugitive emissions standards in NSPS OOOOb or an applicable approved state plan or applicable Federal plan. 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 leak monitoring.

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. 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 congressional 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 which can be highly effective.

F. Pneumatic Devices

EPA proposes six updates to the estimation of emissions from pneumatic devices, which we comment on below.

Update to emission factors in the production and gathering and boosting segments

EPA is proposing updated emissions factors based on more recent measurement data; these factors are much higher for low bleed controllers, slightly lower for intermittent bleed controllers, and fairly comparable for high-bleed controllers (see comparison tables below).

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). Further, they propose alternative emission factors (seen in parentheses in the table below). EPA notes that they calculated alternate emissions factors for production and gathering and boosting due to "uncertainty related to short measurement periods during the Allen *et al.* (2015) 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 15-minute measurement would fail to accurately assess emissions from an actuation, and thus underestimate emissions from the controller.

However, these concerns about short measurement periods also apply to the API Field Study– this study used a sample period of approximately 15 minutes. In contrast, the DOE G&B Study conducted measurements that lasted approximately 3 days. To our knowledge, this is the only study that has measured emissions for this length of time. This is important because a shorter measurement period can result in a significant measurement error.[44]

Luck et al. present analysis of the measurements done in the DOE G&B study. They 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.[45]

While the total number of controllers measured is lower in Luck than in Tupper, the Luck study measured each controller for approximately 3 days (as opposed to 15 minutes in Tupper). In many cases, the controller appeared to be operating properly in the first 15 minutes, but later on in the 3 day period, a malfunction occurred. Luck defines its criteria for determining whether an intermittent bleed controller is malfunctioning as the following:

---

[44] Benjamin Luck et al., *Multiday Measurements of Pnuematic Controller Emissions Reveal the Frequency of Abnormal Emissions Behavior at Natural Gas Gathering Stations*, 6 Env't Sci. Tech. Letters 348 (2019).
[45] *Id.*

“Four criteria were assigned to classify intermittent vent controllers as normally or abnormally operating. If the emissions trace for an intermittent vent device was observed to violate any of these criteria, the controller was identified as abnormally operating.

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

Luck conducted a Monte Carlo analysis to determine how large the measurement error would be if one were to observe the pneumatic controller for 15 minutes rather than 3 days.[46] “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%].” This Monte Carlo analysis included all the controllers in their sample, both continuous and intermittent bleed, and it analyzed the actual measured emissions rate rather than simply the determination of functioning vs. malfunctioning.

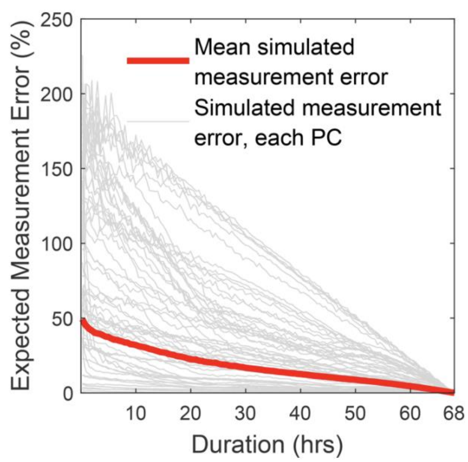

Figure 3 Simulated measurement error of the 61 PC emission recordings with durations of ≥68 h

In order to separate out results for intermittent controllers and to distinguish between functioning and malfunctioning controllers, CATF did an independent review of the Supporting Information published alongside the Luck study. We determined that 10 of the 25 malfunctioning intermittent controllers were malfunctioning from the beginning of measurement, and the other 15 were determined to be malfunctioning based on observations after the first hour of measurement.[47]

[46] *Id*.
[47] Benjamin Luck et al., *Methane Emissions from Gathering and Boosting Compressor Station in the U.S. Supporting Volume 1: Multi-Day Measurements of Pneumatic Controller Emissions*, Co. State Univ. (2019), https://mountainscholar.org/handle/10217/194543.

This means that if they had only taken measurements for 15 minutes, as Tupper did, they would have found only 10 of 40 intermittent bleed controllers malfunctioning, a 25% malfunction rate.

Therefore, it is clearly inappropriate for EPA to base emission factors on studies that used a 15-minute (or less) measurement period.

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.

Table 2. Pneumatics Emissions 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

The DOE G&B Study focused on G&B stations, but it is appropriate to apply these emission factors to the production segment as well. Ever since G&B was added to the GHGRP in 2016, the pneumatic emission factors were the same as those for the production segment. And, in the current proposal, EPA considers these two segments together, without any indication that emission factors diverge between the two segments. Therefore, it is appropriate to use the emission factors from the highest quality study (DOE G&B Study) and apply these factors to both the production and G&B segments.

EPA should exercise caution in relying on the API Field Study (Tupper, 2019) in setting emissions factors, as this study has not been peer-reviewed and the underlying data supporting its conclusion is not publicly available. Rather, the only publicly-available information on the study comes from an 11-slide presentation that was presented at the 2019 EPA Stakeholder Workshop on Oil and Gas. In contrast, for the DOE G&B Study (including Zimmerle, 2019, Luck, 2019, and Vaughn, 2021), all data is made publicly available.[48] It is impossible to critique the methodology or conclusions of Tupper et al. without transparent and granular data. Peer review is preferable, but it is not always possible. However, it should always be possible to make data supporting emissions factor determinations available in a granular and transparent manner. EPA should use a high bar when evaluating data quality and validity used to establish emission factors, and we therefore caution against EPA's use of this study.

Update to emission factors in the transmission and storage segments

To calculate EFs for low and high bleed pneumatics, EPA directly employs EFs from their analysis of the aggregate Zimmerle et al. (2015) continuous bleed emission factor along with

[48] Colorado State University, *Data – Characterization of Methane Emissions from Gathering Compressor Stations* (last visited Oct. 4, 2022), https://mountainscholar.org/handle/10217/195489.

Subpart W data.[49] They back-calculate an effective high bleed emission factor based on the prevalence of high and low bleed devices as reported in Subpart W and our assumed low bleed device emission rate. For intermittent devices, EPA used the average intermittent bleed EF from the GRI/EPA study (1996e). This analysis is used to create new EFs for transmission and storage.

We support EPA's proposed update to pneumatic device emissions 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."[50] We are concerned about potential device malfunctions and encourage EPA to pursue measurement data on pneumatic devices, particularly intermittent devices, in these industry segments.

Table 3. Pneumatics Emissions 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

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 emissions 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.

Alternative methodology: differentiation functioning and malfunctioning intermittent bleed pneumatic controllers

EPA proposes an alternate methodology for remaining intermittent bleed pneumatics based on the results of inspections. This methodology employs EFs from a 2019 API Field Measurement Study (see comments above about lack of transparency and granular data with regard to the API Field Measurement Study). For the reasons outlined below, EPA's proposed alternative methodology for intermittent bleed pneumatic controllers would produce a large underestimate of emissions, and we urge EPA not to adopt this alternative methodology. As EPA notes in its

[49] See Mark de Figueiredo & Stephanie Bogle, Technical Support for Revisions and Confidentiality Determination for Data Elements Under the Greenhouse Gas Reporting Rule; Proposed Rule – Petroleum and Natural Gas Systems Docket ID No. EPA-HQ-OAR-2019-0424 (2020) at Table 2-10.
[50] *Id.*

proposal, they envision very few natural gas pneumatics upon implementation of OOOOb and OOOOc. For the few intermittent bleed pneumatic controllers that remain, EPA has proposed an alternative methodology that requires monitoring surveys using OGI cameras, as those rules would require, 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 controllers.

We understand why EPA has pursued this approach. It would be good to have more granular data on controllers operating properly and those that are malfunctioning which might allow EPA to track emissions going down as increased monitoring (hopefully) makes the overall malfunction rate decline. However, as we describe and document below, there are serious flaws with this bifurcated approach. Most importantly, there is no appropriate emissions factor for malfunctioning intermittent pneumatic controllers detectable using OGI, which, due to its lack of sensitivity for lower emission rates, finds a far lower portion of malfunctioning controllers than were found by Tupper et al. and other studies which used more involved methods to study the emissions of intermittent controllers. Since the Tupper et al emissions factor for malfunctioning controllers includes all controllers that were determined to be malfunctioning using the more sensitive high-volume sampler, it includes emissions rates for lower-emitting malfunctioning controllers, *which would not be detected with OGI*. This means that the Tupper et al emissions factor for malfunctioning controllers (24.1 scfh) is too low for the set of controllers that would be identified as malfunctioning with OGI, which will only detect the highest-emitting 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 clearly found that 15 minutes is not sufficient time to determine whether a controller is malfunctioning. Indeed, 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. But using a less sensitive monitoring technology (OGI) over an even shorter time period than 15 minutes, as OOOOb/OOOOc would require, will result in identifying an even lower number of malfunctioning controllers.

Indeed, data from production sites in Colorado shows that surveys conducted with OGI find much lower malfunction rates. As described in the 2020 Colorado Pneumatic Controller Task Force (PCTF) Report to the Colorado Air Quality Control Commission, a field study was carried out in 2018 under the auspices of the PCTF to study the operation of these devices in the non-attainment area (NAA). 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).[51]

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

Stovern et al. also studied pneumatic controllers in the Denver-Julesberg basin in 2018. This study directly observed that 11.3% of the intermittent controllers were emitting continuously, due to a maintenance 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.[52] 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 and Stovern et al studies 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 Tupper paper, which EPA seeks to rely on.

Similarly, since OGI is less sensitive than a high-volume sampler, operators will classify many lower-emitting controllers that are actually malfunctioning as "properly operating." It would be inappropriate to use the Tupper et al emissions factor for properly-operating controllers (0.3 scfh) for all controllers that "pass the OGI test," since Tupper et al. classified lower emitting malfunctioning controllers that would pass that test as malfunctioning controllers. Therefore, 0.3 scfh would be too low.

Finally, we note that with the passage of the Waste Emissions Charge in the Inflation Reduction Act, many operators will be required to pay a charge of $900–$1,500 per metric ton of methane emissions for all emissions above a threshold set by the Act. Based on simple analysis of past GHGRP reports, a substantial number of onshore oil and gas production operators will have reported emissions above the Act's threshold, and therefore will be required to pay $900 per metric ton of methane emissions in 2024, rising to $1500 per ton in 2026 and thereafter.

An operator reporting the presence of a malfunctioning controller, emitting 24.1 scfh of whole gas, will therefore be reporting over 52 MCF of whole gas emissions, assuming the controller was emitting since the last inspection (and the site is subject to quarterly inspections). Assuming that the gas is about 80% methane by volume, 52 MCF of gas contains 0.8 metric tons of methane. Therefore, under EPA's proposal, operators would be required to pay about $720 for each reported malfunctioning controller found during quarterly inspections in 2024, provided the operator's emissions exceed the emissions threshold (which many of them do).

It is important to note that this cost is likely to lead some operators to under-report the occurrence of malfunctioning controllers (and therefore, their emissions). Given the somewhat subjective nature of OGI inspections, this factor should not be dismissed.

In summary, EPA should not adopt the alternative methodology utilizing separate emissions factors for malfunctioning and properly operating intermittent controllers, based on OGI inspections, due to the lack of appropriate emissions factors for intermittent controllers that have

[52] Michael Stovern et al., *Understanding oil and gas pneumatic controllers in Denver-Julesburg basin using optical gas imaging*, 70 J. Air & Waste Management Ass'n 9 (2020), https://doi.org/10.1080/10962247.2020.1735576.

"passed" or "not passed" an OGI inspection, and the problematic incentives that the Waste Emissions Charge would create if such a methodology were in place.

Clarify operational hours for pneumatics as "in service" not "in operation" to correct misinterpretations

We support EPA's proposal to revise the definition of variable "Tt" in Equation W-1 and the corresponding reporting requirement in 40 CFR 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.[53] By updating this definition to "in service," EPA can close this reporting loophole and more accurately quantify emissions.

Updates for pneumatic pumps

We support EPA's proposal to revise the definition of variable "T" in Equation W-2 in 40 CFR 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 their proposal to use that same term in the corresponding reporting requirement in proposed 40 CFR 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.

We support EPA's proposal to include flared emissions from natural gas driven pneumatic pumps in the calculation of total flare and flare stack emissions. We also 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.

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.

G. 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

[53] 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.

with OGI. The emission factors developed by combining the data from Zimmerle et al. (2020) and Pacsi et al. (2019) are an improvement from the outdated factors currently being used, but as described more below, still do not account for large, intermittent emissions. 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.

We strongly support 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.[54] It is important, as EPA has recognized, that reporters using this option quantify and report all leaks identified during a facility-wide "complete leak detection survey." Otherwise, reporters could not 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.[55] 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 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.

H. Equipment Leaks by Population Count and Population Emission Factors

Subpart W also allows reporters to follow an 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.[56] 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 Method 1 to estimate component counts.[57]

[54] 86 Fed. Reg. 36976-77.
[55] 40 C.F.R. § 98.234.
[56] 86 Fed. Reg. 36979.
[57] *Id*. at 36980.

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. 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. This would reduce reporter burden and reduce the number of errors in the calculation of emissions, leading to better overall emissions estimates. And 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, 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 revisions to emissions factors that allow for statistical incorporation of these emissions in order to lead to accurate estimates.

Rutherford et al., 2021 provides an example for how large emission events can be accounted for using a bottom-up emission factor approach. 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."[58] 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 adopt emission factors that account for large intermittent emission events using statistical methods when developing emission factors. The failure to account for these emissions will lead to inaccurate underestimation of emissions.

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. 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 3700 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.

[58] de Figueiredo & Bogle, *supra* note 49.

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 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 will 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.

Table 4. Population Emissions factors at 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
Dehydrator	6.78	3.1
Heater Treater*	6.52	0.12
Storage Vessel	Multiple EFs	0.85

Table 5. Population emission factors at 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

Flared emission reporting

We support the additional reporting requirements for the individual flare stack characteristics, which are necessary to better understand the relationships between flare taxonomy and operation. In addition to flare unit characteristics, we suggest 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 it clearer on how to report flared gas emissions and the requirement of reporting flare stack characteristics will enrich the reporting program's 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.

Flare combustion efficiency

The GHGRP currently allows operators to assume 98% combustion efficiency of converting natural gas CH_4 into CO_2 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.[59] 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 CH_4 emissions and is a contributing factor to the divergence between EPA estimates and top-down estimates based on empirical measurements.

[59] 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.

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).[60] 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.[61] 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.

Unlit flares

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.[62] 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.[63]

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.

[60] *Id*.
[61] *Id*.
[62] Lyon et al., *Concurrent variation*, *supra* note 19.
[63] *Id*.

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?”

Associated Gas Venting and Flaring

EPA has also proposed several updates related to the estimation and reporting of associated gas venting and flaring. First, it includes elements that would allow for the use of continuous flow measurement devices to be used for estimating flaring emissions. And, if such a device is present, it requires operators 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 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. However, 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 EPA’s clarification and the update suggested above 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. Overall, incorporating just a few requirements for measurement devices, such as continuous flow measurement devices for flare units or flare temperature sensors, will better the estimates for many reported emission sources and bring reported vented and flared emissions closer to achieving the imperative to empirically quantify methane emissions set forth by U.S. Methane Emissions Reduction Action Plan.

I. Compressors

This section comments on a number of items the EPA has raised related to compressors and engines:

- Compressor Methane Slip
- Engine Crankcase Venting
- Reciprocating Compressors
- Dry seal centrifugal emission factors
- Proposal to include standby pressurized mode for centrifugal compressors

We also recommend that LNG Import/Export facilities continuously monitor engine emissions, or at least use frequent stack testing rather than default emission factors. This recommendation is discussed in more detail in Section O, LNG Related Processes.

Compressor Methane Slip

We are generally supportive of EPA's proposal to update the emission factors for uncombusted methane emissions in exhaust (i.e., "methane slip") from compressor engines. The table below, taken from EPA's TSD, shows how different emission factors have been used for different sizes and different types of engines.[64] EPA then used 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.

Figure 4. Emission Factor Comparison (kg CH_4/MMBTU)

For example, the U.S. Greenhouse Gas Inventory ("USGHGI") uses the same emission factor for large and small engines, both rich- and lean-burn. The GHGRP uses the same factors for all sizes and types as well, but that factor is <u>much</u> smaller than the USGHGI. However, two other sources, Zimmerle *et al.* (2019) and AP-42 use different factors for different types of engines. We agree that it is appropriate to use AP-42 emission factors for 2SLB engines, and Zimmerle emission factors for 4SLB and 4SRB engines.

[64] de Figueiredo & Bogle, *supra* note 49.

However, Vaughn *et al.* (2019) (part of the same DOE G&B Study as Zimmerle 2019)[65] further supports the use of different emission factors for 4SLB engines depending on the model and size of the engine. As seen in Figure 5, the mean methane slip measured from 4SLB engines was 1.15 lb/MMBtu (0.522 kg/MMBtu), and mean methane slip measured from 4SRB engines was of 0.10 lb/MMBtu (0.045 kg/MMBtu), much lower than the measured mean methane slip of from 4SLB.[66] The use of different factors for rich burn vs. lean burn engines is well supported and we support EPA's proposal to do so.

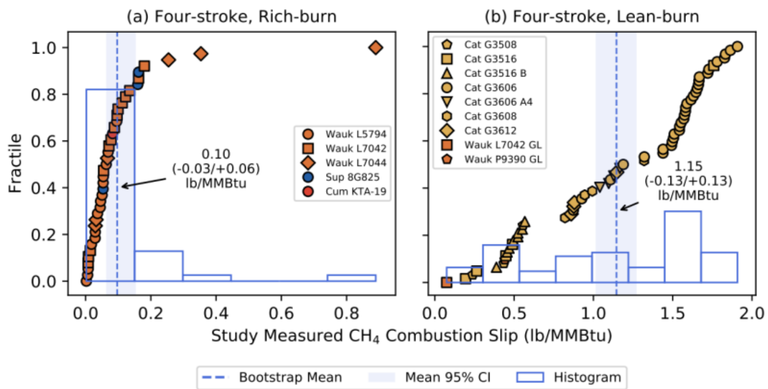

Figure S2-17: Combustion slip emission rates measured in this study using the in-stack tracer method for (a) four-stroke, rich-burn and (b) four-stroke, lean-burn engines. Mean combustion slip measured as found was (a) 0.10 (-0.03/+0.06) lb/MMBtu for 4SRB engines and (b) 1.15 (-0.13/+0.13) lb/MMBtu for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

Figure 5. Combustion slip emission rates for rich-burn and slow-burn engines from Vaughn et al. (2019).

However, there is a clear stratification in emissions within 4SLB engines, as seen in Figure 5, 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."[67] Figure 6 shows that 4SLB engines in the Caterpillar G3500 series have average emissions of 0.52 lb/MMBtu (0.24 kg/MMBtu) while engines in the larger Caterpillar G3600 series have average emissions of 1.41 lb/MMBtu (0.64 kg/MMBtu). Based on the measurements in Vaughn, *et al.* (2021), CATF supports further differentiation in emission factors for methane slip to be based on the engine model.

[65] Vaughn et al., *Methane Exhaust Measurements at Gathering Compressor Stations in the United States*, 55 Env't. Sci. Tech. 1190 (2021), https://pubs.acs.org/doi/10.1021/acs.est.0c05492.
[66] *Id.*, at 1192.
[67] 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.

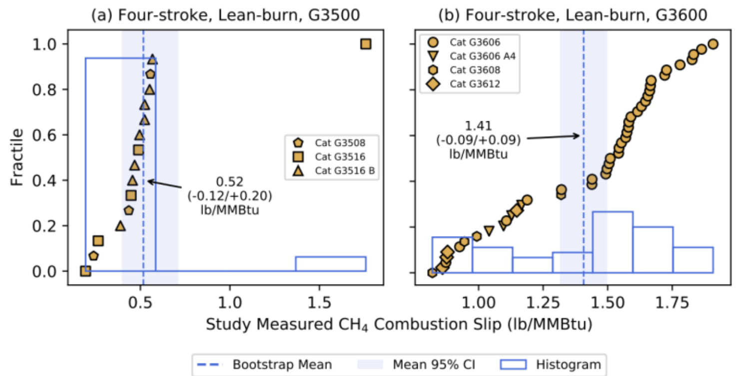

Figure S2-18: Combustion slip emission rates measured in this study using the in-stack tracer method for two 4SLB engine models. Combustion slip from engines in the (a) Caterpillar G3500 series were 0.52 (-0.12/+0.20) lb/MMBtu on average, or 59% lower than the AP-42 4SLB emission factor. Combustion slip 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 6. Combustion slip emission rates for two 4SLB engine models from Vaughn et al. (2019).

Engine Crank Cases

Relatedly, we also call on 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%.[68] The measurements are illustrated in Table 6.

Table 6. Comparison of Combined Exhaust and Crankcase (CC) Methane Emissions Rates with Those Predicted by AP-42. Reproduced from Johnson et al. (2015).

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, 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. In addition, once this source is quantified and tracked by the EPA, it will incentivize

[68] Johnson et al., *Methane Emissions from Leak and Loss Audits of Natural Gas Compressor Stations and Storage Facilities*, 49 Env't Sci. Tech. 8132 (2015), https://pubs.acs.org/doi/pdf/10.1021/es506163m.

researchers to work to conduct additional measurements to improve the precision of these factors.

Reciprocating Compressors

Finally, we would like to note that EPA's proposed methods for reporting emissions from reciprocating compressors should be reasonable as long as the measurement is done correctly and in a way that will capture all of the places that methane is venting. Often rod packing vents are manifolded together, so it is important for the reporter to know the design to fully and accurately measure the emissions from these vents.

Proposal to include dry seal centrifugal emission factors

We support EPA's proposal to add dry seal vents to the defined compressor sources for centrifugal compressors and 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.

Proposal to include standby pressurized mode for reciprocating and wet seal oil degassing vent in centrifugal compressors

While the standby pressurized mode is less common, emissions do occur during this mode, and adding this will provide clear guidance to operators.

J. Storage tanks

EPA has proposed several updates to the reporting requirements for storage tanks that will improve the accuracy of data collected. First, they provide clarification for operators on how to estimate the amount or gas that is captured using a vapor recovery unit or sent to a flare. They note that 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.[69] 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.[70]

[69] Zavala-Araiza et al., *Super-emitters*, *supra* note 19; Lyon et al., *Aerial surveys*, *supra*, note 27; Rutherford et al., *supra*, note 15.
[70] *Id.*

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 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.

K. Distribution Lines

EPA has proposed to amend the subpart W emission factors for distribution mains using the measurements from Lamb *et al.* combined with the pipeline material specific leaks per mile data from Weller *et al.* We disagree with this approach, as it would not be internally consistent to combine the leak rate (scf/hr/leak) and the leak frequency (leaks/mile) from two different studies with vastly different methodologies and measurement methods. As we note below, we have significant concerns with the Lamb et al. study, and therefore we recommend that EPA amend the subpart W emission factors for distribution mains using both the measurements and the pipeline material specific leaks per mile data from Weller *et al.*

In a January 2016 comment submitted as part of the GHG Inventory review process[71], we raised significant concerns with the methodology used in Lamb for estimating leak frequency. We summarize these comments as follows:

- This methodology is logically flawed: the algebra is not consistent with the approach operators take to surveying distribution systems for leaks. Furthermore, the underlying data for leak counts presented in Lamb et al. (2015) are not consistent with the definitions used by Lamb et al. It appears that some of the partner companies misinterpreted survey questions, so the underlying data is also flawed.
- Lamb et al. assume that operators surveying distribution systems find 85% of leaks, based on the same assumption in the 1990s GRI study. The GRI study attributed that assumption to information from a single partner company; no data or explanation is provided to substantiate the claim. Recent data presented by PG&E at a recent Gas Star meeting contradicts this assumption and shows that less than 85% of leaks are found using typical surveys.
- The leak per mile frequencies that EPA proposed in the December 2015 memo are inconsistent with the results from vehicle-based leak surveys that have been published in recent years. These surveys found significantly higher leaks in cities with significant amounts of outdated pipelines than the leak-per-mile frequencies EPA proposed would predict.

We further noted that top-down analyses have shown that emissions from natural gas distribution in two urban areas, Boston and Los Angeles, are considerably higher than EPA's 2015 GHG Inventory implied. The proposed changes to the Inventory will substantially reduce the estimate of emissions from Distribution, exacerbating the gap between what was measured in those cities and what the Inventory predicts.

Considering these internal flaws and inconsistencies with recent observations, we recommended against updating emissions factors for underground pipeline leaks based on Lamb et al. At the

[71] Clean Air Task Force, *Comment on EPA's December 2015 Memorandum "Inventory of U.S. Greenhouse Gas Emissions and Sinks: Revisions under Consideration for Natural Gas Distribution Emissions"* (Jan. 2016).

time, however, this was the only bottom-up study of underground distribution systems, and EPA chose to update the GHG Inventory based on the emission factors presented in Lamb et al.

However, the Weller et al. paper, published in 2020, did not contain the methodological issues we noted in Lamb et al., and it also has a much larger sample size of measured leaks. Despite EPA's note that the quantification used in Weller (AMLD) does not appear to be as accurate as the standard measurement method of modified high flow sampling utilized in the Lamb study, the authors of the Weller study were able to correct for the observed error. And, as they note, the larger sample size likely captures a wider (and more accurate) range of potential leak rates. Thus, both the leak rate and leak frequency from the Weller study are more reliable, and should be used to update the GHGRP emission factors.

L. Gathering Lines

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.[72] From each campaign, they quantified emission factors ranging from 2.7 to 10.0 metric tons CH_4 per kilometer per year (4300 to 16,000 kilograms CH_4 per mile per year), which are 14-52 times higher than the EPA's GHGI estimate of 310 kilograms CH_4 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 (Chen et al. 2022 and Cusworth et al. 2022), a large sample size is necessary to identify rare but large emission sources.[73]

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 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.

This study offers a useful first look into quantifying gathering pipeline emissions using aerial measurement data, but there are two main limitations of this study 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

---

[72] Jevan Yu et al., *Methane Emissions from Natural Gas Gathering Pipelines in the Permian Basin*, Env't Sci. Tech. Letters (2022), https://pubs.acs.org/doi/full/10.1021/acs.estlett.2c00380.
[73] Chen et al., *Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey*, 56 Env't Sci. Tech. 4317 (2022), https://doi.org/10.1021/acs.est.1c06458; Daniel Cusworth et al., *Strong methane point sources contribute a disproportionate fraction of total emissions across multiple basins in the United States*, 19 PNAS 38 (2022), https://doi.org/10.1073/pnas.2202338119.

gathering line emissions in regions beyond the Permian. 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.

Other Gathering and Boosting Segment item

A significant data gap current exists in reporting for the G&B segment. Companies report emissions and activity data by facility, which for this segment is defined as the entire basin. However, companies are not currently required to report the total number of gathering and boosting stations in each basin facility. This piece of activity data would greatly improve stakeholder ability to understand reported emissions. And, it is less burdensome than the current requirement in the Production segment to report the number of wells in each basin facility. Thus, we recommend that EPA add this critically important data element to the reporting requirements for companies in the G&B segment.

M. Liquids Unloading

We support EPA's proposal to require reporting on the type of unloading 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. 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.[74] 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 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 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

[74] 86 Fed. Reg. 63179

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.[75]

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 to understand how often non-emitting methods are being used and how often those methods fail and result in unintentional 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 the GHGRP will allow stakeholders to readily access this information and evaluate emissions from various liquids unloading practices.

N. Acid Gas Removal Venting, Nitrogen Removal Venting, and LNG Related Processes

EPA currently requires operators to report CO_2 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 segments. EPA proposes a number of updates to improve CO_2 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.

An update to require LNG Import/Export facilities to report CO_2 emissions from AGRUs

The EPA's proposal to revise GHGRP to include reporting of CO_2 emissions from Acid Gas Removal Units (AGRU) vents at LNG Import/Export facilities is a significant improvement. Facilities in the Onshore Petroleum and Natural Gas Production, Onshore Natural Gas Processing, and Onshore Petroleum and Natural Gas Gathering and Boosting segments are already required to report CO_2 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 CFR 98.233(d) and report emissions as currently provided in 40 CFR 98.236(d). We strongly support this proposal.

An update to AGRU solvent reporting guidelines

For all industry segments required to report CO_2 emissions from AGRU vents, EPA is also proposing to replace the requirement to report solvent weight with solvent type, and in the case of specific amine-based solvents, the general composition. The solvent weight requirement did not clarify how the operator should calculate the value, and it introduced inconsistently among operators. As stated in the revision, the solvent weight also does not provide enough details

[75] *Id*.

about the Acid Gas Removal Unit to verify reported data and characterize AGRU vent emissions. As such, this change proposed by EPA is supportable.

Requiring facilities in Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, Onshore Natural Gas Processing and LNG Import/Export segments to report methane emissions from Acid Gas Removal Units Vents

Methane emissions from AGRU vents are not required to be reported in the current GHGRP for any industry segment, but AGRU units are a significant source of methane emissions, and EPA should require reporting of these emissions.

EPA's US Greenhouse Gas Inventory (US GHGI) estimates that AGRU vents at processing plants nationwide emitted 14,500 metric tons of methane in 2020. Notably, this is more than is emitted by several sources of methane which GHGRP requires processing plant operators to report, or proposes to require operators to report, in this rulemaking. EPA's estimate is based solely on the 1996 GRI study, which modeled emissions from AGRU vents and found a potential emissions factor of 965 scf methane / MMSCF of treated gas. This potential emissions factor (methane emissions of ~0.1% of treated gas for all gas requiring AGRU treatment) suggests that AGRU vents may be a significant source, since the overall leak rate for delivered US natural gas implied by the US GHGI is only 1.3%. The GRI study assumed that only 18% of this gas is vented. It also creates a national estimate of AGRU emissions by normalizing emissions per AGRU, rather than AGRU throughput, and uses an estimate of the number of AGRUs installed nationwide. Apparently, none of these assumptions have been re-examined in the 25 years that have passed since this report was published: EPA has just used activity drivers to adjust the estimate of the number of AGRs. Among other things, EPA estimates that the number of AGRs has declined since 1990, and implicitly assumes that their throughput per unit has remained constant, since the emissions factor per AGRU has remained constant. Since US gas production has roughly doubled since 1990, this approach is questionable at best.

It is important to recognize that these methane emission rates may vary dramatically by site because they depend on the feed gas composition, acid gas removal technology, AGRU separation efficiency, facility vent system design and amount of CO_2 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. Due to the lack of detailed information available about the fraction of methane emissions from the AGRU that is vented directly to the atmosphere per facility, EPA should strongly consider adding methane reporting requirements from all AGRU vents to characterize methane emissions more accurately from these facilities. Since a number of factors influencing methane emissions from AGRU vents may be under operator control, or may be determined by facility design, requiring operators to report AGRU methane emissions would call attention to this source and potentially reveal mitigation opportunities.

For AGRU vents that are directly venting into the atmosphere, EPA should require operators to use continuous emissions monitoring system (CEMS), vent meters, simulation software, or calculation methods that use mass balance equations to account for the vented methane emissions.

Requiring facilities in Onshore Natural Gas Processing, and LNG Import/Export segments 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. EPA does not require reporting of methane emissions from NRUs for any industry segment, but these emissions can be significant, and operators of NRUs in the gas processing, LNG storage, and LNG import/export segments should be required to report these emissions.

Natural gas feed with nitrogen levels greater than 7% generally undergoes nitrogen removal because maximum nitrogen content in pipelines is typically set between 4-7%.[76] Studies performed by Gas Research Institute in 1993 found that 14% of known reserves in the U.S. are subquality due to high nitrogen content.[77] Production from these contaminated reserves has been substantial for many years. A report produced by Membrane Technology and Research, Inc., for the Department of Energy in 1999 gives a regional distribution of high-nitrogen reserves, with nitrogen concentrations 4% or more, in the US.[78]

Table 7. Distribution of Non-Associated Gas with 4% or More Nitrogen in 1988 Reserves.[79]

Region	High Nitrogen Natural Gas (TCF)
Mid-Continent	15.31
Rocky Mountain Foreland	3.61
Arkla-East Texas	1.67
Permian Basin	0.94
West Coast Onshore	0.89
Williston Basin	0.4
Midwest	0.3
Appalachia	0.1

The report lists several natural gas processing facilities with NRUs in the 1990s and provides the plant capacity and nitrogen content in the feed gas entering the processing facility.[80] Many of the facilities highlighted in the report have continued operation to this day and routinely emit methane from the NRU vents and must be required to report their methane emissions.

[76] Kuo et al., *Pros and cons of different Nitrogen Removal Unit (NRU) technology*, 7 J. Nat. Gas Sci. & Engineering 52 (2012), https://www.sciencedirect.com/science/article/abs/pii/S1875510012000170.
[77] U.S. Office of Scientific and Technical Information, *Nitrogen removal from natural gas* (2017), https://www.osti.gov/servlets/purl/493341.
[78] Membrane Technology and Research, Inc., *Nitrogen Removal from Natural Gas Phase II Draft Final Report* (1999), https://www.osti.gov/servlets/purl/780455/.
[79] *Id*.
[80] *Id*.

This is significant for methane emissions because the nitrogen vents from NRUs are typically contaminated with methane. Existing literature cites methane content in the concentrated nitrogen vent stream to range between 0.5-3% based on the design and operation of the NRU.[81] Simple arithmetic dictates that if raw natural gas contains 15% nitrogen, and this is reduced to 5% using NRUs which vent a mixture of 97% nitrogen and 3% methane, the nitrogen removal process vents over 0.3% of its output processed gas as methane – a very significant contribution to the total emission rate for that gas. Given the large quantity of nitrogen-contaminated gas being produced today, and potentially in the future, this source could certainly account for tens of thousands of tons of methane emissions annually. Additionally, as facilities increase the flowrate through the NRU to increase production of natural gas, the operation efficiency of the NRU may decrease which increases the amount of methane in the nitrogen vent stack.[82] Facilities processing a large amount of nitrogen-contaminated natural gas, can be venting a significant amount of methane emissions, and should be accounted for in the GHGRP. Furthermore, optimization of NRUs can significantly reduce emissions,[83] so requiring operators to report NRU methane emissions call attention to this source of potential mitigation.

EPA should require operators to use a continuous emissions monitoring system (CEMS), vent meter, simulation software, or calculation methods that use mass balance equations to account for and report the vented methane emissions from all NRU vents. EPA should also take measures to investigate how to improve methane emissions reporting requirements from the vent stack associated with NRUs.

Require LNG Import/Export facilities to continuously monitor engine emissions

Stationary fuel combustion can be a major source of GHG 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. A survey by Marcogaz, a European natural gas technical association, estimated average emissions from LNG import terminals to be 165 grams of methane/metric ton of LNG with unburned methane in the exhaust gases from gas turbines, gas engines and combustion equipment and flares contributing to 5% of the total methane emissions.[84] The report also found that 83% were fugitive methane emissions from compressors and high-pressure areas of the terminal.

Currently, EPA requires that facilities report hourly averaged CO_2 emissions from stationary fuel combustion sources using continuous emissions monitoring systems (CEMS) under Subpart C. However, for methane emissions, EPA requires LNG import and export facilities to use of emission factor of 1 gram of methane per MMBTU as recommended by the IPCC Guidelines for

[81] EPA, *Nitrogen Rejection Unit Optimization* (2011), *available at* https://www.epa.gov/natural-gas-star-program/recommended-technologies-reduce-methane-emissions.
[82] *Id.*
[83] *Id.*
[84] Marcogaz, *Survey Methane Emissions for LNG Terminals in Europe* (2018), https://www.marcogaz.org/wp-content/uploads/2021/04/WG-ME-17-22.pdf.

National Greenhouse Gas Inventories (2006).[85] As previously noted by several academic studies, these emissions factors have not been well tested and may underestimate emissions.[86] Additionally, Greenhouse Gas Inventory (GHGI) uses an emission factor of 3.9 grams of methane per MMBTU for combined cycle and combustion turbines. We strongly urge EPA to require continuous emissions monitoring for methane emissions in the exhaust of stationary fuel combustion equipment, as currently required for CO_2, in all LNG facilities to accurately account for fugitive methane leaks.

IV. Subpart HH

A. Shortcomings of First Order Decay Models

While we support EPA's efforts to improve emissions reporting requirements for municipal solid waste landfills, we would urge EPA to give consideration to research suggesting these bottom-up emission estimation methodologies are inherently flawed.[87]

First order-decay (FOD) methane emissions models, like those utilized in Subpart HH and the U.S. Greenhouse Gas Inventory, were developed early in the lifetime of waste sector emissions quantification studies – around the same time as the first field studies on methane emissions from landfills in the 1980s and 1990s.[88] Since that time, these FOD models have been neither significantly updated nor adjusted. Unfortunately, these models and the assumptions used in them contain serious shortcomings that inhibit fully accurate understanding of landfill emissions.[89] Recent studies have utilized remote sensing technology to measure landfill emissions and have found that there are significant discrepancies between the emissions estimated per FOD models and measurements via remote sensing.[90]

We acknowledge that the updates to the FOD methodology presented in the proposed revisions to the GHGRP are intended to add flexibility while improving accuracy for landfill operators

---

[85] Institute for Global Environmental Strategies for the IPCC, *2 IPCC Guidelines for National Greenhouse Gas Inventories* 2.16 (S. Eggelston et al., eds., 2006).
[86] A. R. Brandt et al., *Methane Leaks from North American Natural Gas Systems*, 343 Science 733 (2014).
[87] Cusworth et al., *Using remote sensing to detect, validate, and quantify methane emissions from California solid waste operations*, 15 Env't Rsch. Letters 054012 (2020), https://iopscience.iop.org/article/10.1088/1748-9326/ab7b99.
[88] Kurt Spokas et al., *From California Dreaming to California Data: Challenging Historic Models for Landfill CH_4 Emissions*, 3 Elementa 51 (2015), https://online.ucpress.edu/elementa/article/doi/10.12952/journal.elementa.000051/112713/From-California-dreaming-to-California-data.
[89] Lavoie et al., *Aircraft-Based Measurements of Point Source Methane Emissions in the Barnett Shale Basin*, 49 Env't Sci. & Tech. 7904 (2015), https://doi.org/10.1021/acs.est.5b00410.
[90] *See* Xinrong Ren et al., *Methane Emissions from the Baltimore-Washington Area Based on Airborne Observations: Comparison to Emissions Inventories*, 123 J. Geophysical Rsch.: Atmospheres, 8869 (2018), https://agupubs.onlinelibrary.wiley.com/doi/10.1029/2018JD028851; Joannes D. Maasakkers et al., *Using Satellites to Uncover Large Methane Emissions from Land-fills*, 8 Sci. Advances (2022), https://www.science.org/doi/10.1126/sciadv.abn9683; *see also* Hamid R. Amini HR et al., *Comparison of first-order-decay modeled and actual field measured municipal solid waste landfill methane data*, 33 Waste Mgmt. 2720 (2013), https://pubmed.ncbi.nlm.nih.gov/23988298/; Riley M. Duren et al., *California's methane super-emitters* 575 Nature 180 (2019), https://doi.org/10.1038/s41586-019-1720-3.

with varying levels of data availability. However, considering the discrepancies that are evident with FOD models, it is likely that these changes will not actually contribute to increased accuracy. According to the National Academy of Sciences ("NAS"), recent changes to the GHGRP methodology have yet to be field validated for use at specific sites, and may in fact "magnify[ies], rather than reduce[s] the shortcomings of the FOD method".[91] Increased complexity from the proposed changes will likely further magnify these shortcomings.

While remote sensing technology presents exciting opportunities to gather empirical data on landfill emissions, we acknowledge that these methods are not currently practiced at scale by landfill operators to regularly collect data. Luckily, there are options available to produce more accurately modeled emissions estimates. For modeled (rather than empirical) methodologies to yield more accurate results, however, more site-specific data collection is required. At this point in time, many landfill operators are not collecting or reporting the data points necessary to satisfy an improved modeling framework. These data points can include site specific characterization of the waste stream, information on the type, thickness, and coverage of cover soils, and types of improved landfill gas management practices implemented at the site. This information could then be used to improve the degradable organic carbon and k values, methane oxidation, and collection efficiency variables, respectively, used in the modeling approaches.

In order to improve the accuracy of reporting, as well as the overall efficacy of the GHGRP, EPA ought to implement the following tactics: (1) acknowledge the uncertainties linked to FOD models regarding methane emission estimates from landfills; (2) phase in additional required data points for reporting by landfill operators to improve site specific GHGRP methane emission estimates and improve estimation of default values; and (3) begin to incorporate top-down measurements into reporting to validate or support bottom-up modeling estimates. CATF consulted RMI, the Environmental Defense Fund, and Carbon Mapper during the creation of their comments. We support RMI's detailed recommendations to integrate additional site-level data (Section III.A) and advanced monitoring technologies into the GHG reporting requirements (Section III.F).[92]

B. Changes to K Values

EPA's revised approach to default k values will result in an increase in reported emissions from active landfills and reduced emissions from closed and inactive landfills. According to EPA the changes are more in line with Intergovernmental Panel on Climate Change defaults and k values used in countries with similar climates. CATF suggests that EPA consider how the proposed k value changes may impose unintended negative consequences on the collective accuracy of landfill reporting and methane mitigation within the U.S. Specifically, use of the newly proposed k values may lead closed and inactive landfills to cease gas capture operations sooner per New

---

[91] Nat'l Acad. of Sciences, Engineering, and Medicine, *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.

[92] RMI, Comments for the Environmental Protection Agency's Proposed Rule Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule on Subpart HH - Municipal Solid Waste Landfills (2022).

Source Performance Standard requirements.[93] Again, considering uncertainties in the use of FOD models, and the lack of U.S. site-specific data used to estimate these new values, this may have consequences counter to U.S. methane mitigation goals.

C. Gas Capture Reporting

CATF supports and commends EPA on their plan to introduce additional reporting requirements for landfills with gas capture operations. Differentiating between the percentage of methane disposed of through flaring and the percentage of methane delivered to landfill gas-to-energy projects is an important step towards increasing the transparency and understanding of methane mitigation methods from the U.S. waste sector and will improve reporting towards renewable energy targets.

V. Subpart VV: Sources that elect to quantify CO_2 stored using the ISO 27916:2019 methodology should be required to report under subpart VV

We commend EPA for creating a reporting pathway for entities using the ISO 27916:2019 standard to quantify CO_2 stored in association with CO_2-EOR operations. Creation of this pathway is a necessary step for supporting robust monitoring and verification of CO_2 stored. In fact, compliance with the ISO standard necessarily entails reporting much of the data generated under the ISO standard to the "competent governmental entity or entities with legal power to regulate or permit CO_2-EOR" and any associated storage of CO_2.[94] For the U.S., that entails reporting those data elements to EPA.[95] Thus, EPA must provide a means to report the relevant information in the ISO standard in order for entities to formally comply with its own terms.

However, EPA's language, as proposed, could be read by operators to imply that CO_2-EOR operators may be able to remain under subpart UU, even while electing to quantify associated CO_2 storage using the ISO methodology for purposes of receiving 45Q tax credits. While the reporting threshold in proposed 40 C.F.R. § 98.481(a) is clear that any project that uses the ISO standard to quantify CO_2 stored must report under subpart VV, the inclusion criteria in proposed 40 C.F.R. § 98.480(a) indicate that a project that remains under subpart UU would not be required to report. This ambiguity presents the risk that a CO_2-EOR operator might choose to report under subpart UU but still quantify CO_2 stored using the ISO methodology and receive 45Q tax credits without the transparency afforded by reporting under subpart RR or proposed subpart VV. This also presents the risk that CO_2-EOR operators could claim compliance with the

---

93 Pradeep Jain et al., *Greenhouse Gas Reporting Data Improves Understanding of Regional Climate Impact on Landfill Methane Production and Collection*, 16 PLoS ONE (2021), https://www.ncbi.nlm.nih.gov/pmc/articles/PMC7909644/.

94 International Organization for Standardization, ISO 27916:2019 § 3.3 (definition of "authority"); *see, e.g.*, ISO 27916:2019 §§ 4.3, 4.4, 9.1, 10.1 (sections specifying documentation or other information to be provided to the authority).

95 EPA retains the legal power to regulate CO_2-EOR, under authorities including the UIC program, even if that authority is delegated to the states through the state primacy program. EPA also has authority to, and does, regulate CO_2 storage in association with EOR. *See, e.g.*, 40 C.F.R. §§ 60.5555(f), 98.426(h) (New Source Performance Standards for greenhouse gases using carbon storage in association with EOR).

ISO 27916 standard for purposes of the 45Q tax credit without formal compliance with that standard's terms regarding reporting to the "authority," i.e., EPA.

To mitigate this risk, EPA should modify its proposed inclusion criteria for reporting under subpart VV to clarify that, if an entity chooses to quantify CO_2 stored using the ISO 27916:2019 methodology for any purpose (e.g., for the purpose of seeking 45Q tax credits), they *must* then report under subpart VV. Removing proposed 40 C.F.R. § 98.480(a)(2) ("[y]ou are not reporting under subpart UU of this part") would be sufficient to clarify this. Sources should be able to elect to remain reporting under subpart UU only if they are not seeking to quantify CO_2 storage in association with their EOR operations.

VI. Energy Consumption: EPA should collect data on energy consumption to enable better understanding of sectors' indirect emissions and decarbonization potential[96]

EPA requests comment on future revisions to the GHG Reporting Rule that would add requirements related to energy consumption. 87 Fed. Reg. at 37016. 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." *Id.* at 37,017. 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 GHG Reporting Rule 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.

CAA 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." 42 U.S.C. § 7414(a)(1). Those requirements are not limited to owners and operators of emission sources. *See id.* 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." *Id.* § 7414(a). 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 GHG 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. 74 Fed. Reg. 56260, 56289 (Oct. 30, 2009). 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

[96] Our comments on energy consumption under the GHGRP were developed in collaboration with the Environmental Defense Fund and contain similar recommendations.

of 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. EPA should collect data on energy consumption from all facilities that are currently reporting emissions under the GHGRP, as well as 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. 87 Fed. Reg. at 37018.

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, *see* 40 C.F.R. § 98.3(c)(4), rather than creating a separate source category for energy consumption.[97]

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 GHG Reporting Rule. 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.[98] 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

[97] 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).
[98] EPA could list these source-category-specific thresholds in Table A-4.

energy consumption and energy attributes from each of its energy purchases, with the threshold being 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 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 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. *Cf.* 74 Fed. Reg. 16448, 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"). Accordingly, the additional requirements would be reasonable, and therefore authorized under section 114.

B. Reported energy consumption information should distinguish between thermal energy products and electricity, and should include any 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." 87 Fed. Reg. at 37018. 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 GHG 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 de-regulated electricity markets and renewable attributes of purchased products)." *Id.* 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.[99] 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. *See* 74 Fed. Reg. at 56289 (indicating that EPA would determine, in a subsequent rulemaking, whether data on electricity purchases could be withheld from publication as confidential business information). It will be important to ensure that EPA's reporting requirements do not discourage entities' efforts to improve energy efficiency or transition to fully electrified processes.

VII. Conclusion

Thank you for the opportunity to submit comments on the proposed updates to the GHGRP. If you have any questions about this submission, please reach out to Alan Masinter at amasinter@catf.us.

Respectfully submitted,

Clean Air Task Force

[99] *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/.