American Gas Association

American Public Gas Association

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1200 Pennsylvania Avenue, NW
Washington, DC 20460

Re: AGA and APGA's Comments on "Waste Emissions Charge for Petroleum and Natural Gas Systems," Docket ID No. EPA-HQ-OAR-2023-0434

The American Gas Association ("AGA") and the American Public Gas Association ("APGA") (jointly, "the Associations") appreciate the opportunity to comment on the U.S. Environmental Protection Agency's ("EPA" or "Agency") proposed rule titled "Waste Emissions Charge for Petroleum and Natural Gas Systems" ("Proposed Rule"), which was published in the *Federal Register* on January 26, 2024.[1] The Proposed Rule would implement the Waste Emissions Charge ("WEC") based on methane ("CH_4") emissions reported by certain segments of the oil and natural gas sector under Subpart W of the Greenhouse Gas Reporting Program ("GHGRP"),[2] as directed by Section 60113 of the Inflation Reduction Act of 2022 ("IRA")[3] via its addition of Section 136 to the Clean Air Act.[4]

Consistent with the IRA and Section 136(d) of the Clean Air Act, the Proposed Rule would not apply the WEC directly to the natural gas distribution segment as the segment is defined in Subpart W.[5] However, natural gas local distribution companies ("LDCs")[6] may be significantly affected by the Proposed Rule, both directly and indirectly. Some LDCs own or operate natural gas equipment in segments of the natural gas value chain other than "natural gas distribution" as

[1] Proposed Rule, 89 Fed. Reg. 5318 (Jan. 26, 2024). EPA published a second *Federal Register* notice extending the comment period through March 26, 2024. *See* 89 Fed. Reg. 12,795 (Feb. 20, 2024).
[2] 40 C.F.R. Part 98, Subpart W ("Petroleum and Natural Gas Systems"). Unless otherwise noted, all citations to Subpart W or any other GHGRP subpart refer to the current version of the regulatory text as of March 26, 2024. These comments will specifically identify any citations to the proposed revisions to Subpart W and the GHGRP, which were proposed prior to the issuance of this Proposed Rule and, as of March 26, 2024, have yet to be finalized.
[3] Sec. 60113 of Public Law No. 117-169 ("Methane Emissions Reduction Program").
[4] 42 U.S.C. § 7436.
[5] *See* 40 C.F.R. § 98.230(a)(8) ("Natural gas distribution means the distribution pipelines and metering and regulating equipment at metering-regulating stations that are operated by a Local Distribution Company (LDC) within a single state that is regulated as a separate operating company by a public utility commission or that is operated as an independent municipally-owned distribution system. This segment also excludes customer meters and regulators, infrastructure, and pipelines (both interstate and intrastate) delivering natural gas directly to major industrial users and farm taps upstream of the local distribution company inlet.").
[6] Most AGA members are investor-owned LDCs and APGA members are municipal or publicly owned utilities. The term "LDC" is used throughout these comments to refer to natural gas distribution entities (*i.e.*, members of both AGA and APGA).

it is defined in Subpart W, and therefore could be directly subject to the WEC. LDC operations in the Subpart W "natural gas distribution" segment may be indirectly, yet still meaningfully, affected by the Proposed Rule based on the degree to which upstream facilities reduce their methane emissions and how these non-LDC entities address their costs of complying with the WEC. Accordingly, both Associations have a demonstrable interest in the WEC and offer the following comments on the Proposed Rule.

I. INTRODUCTION

AGA, founded in 1918, represents more than 200 local energy companies that deliver safe and reliable natural gas throughout the country. There are more than 78 million residential, commercial, and industrial natural gas customers in the United States, of which 95 percent—more than 74 million customers—receive their gas from AGA members. AGA is an advocate for natural gas utility companies and their customers and provides a broad range of programs and services for member natural gas pipelines, marketers, gatherers, international natural gas companies, and industry associates. Today, natural gas meets more than one third of United States energy needs.[7]

APGA is the national, non-profit association of publicly owned natural gas distribution systems. APGA was formed in 1961 as a non-profit, non-partisan organization, and currently has over 740 members in 37 states. Overall, there are nearly 1,000 municipally owned systems in the United States serving more than five million customers. Publicly owned gas systems are not-for-profit retail distribution entities that are owned by, and accountable to, the citizens they serve. They include municipal gas distribution systems, public utility districts, county districts, and other public agencies that have natural gas distribution facilities.[8]

Collectively, AGA and APGA members operate virtually all of the investor-owned, publicly owned, and community-owned natural gas local distribution systems across all 50 states. In general, LDCs are customers of the upstream natural gas entities that will be subject to the WEC. Additionally, some Association members—including entities that are LDCs—own or operate natural gas facilities in Subpart W segments that will be subject to the WEC, including onshore natural gas transmission pipelines,[9] onshore gas transmission compression,[10] underground

[7] For more information, please visit www.aga.org.
[8] For more information, please visit www.apga.org.
[9] *See* 40 C.F.R. § 98.230(a)(10) ("Onshore natural gas transmission pipeline means all natural gas transmission pipelines as defined in § 98.238."). Subpart W does not have a standalone definition for "natural gas transmission pipeline," but it does define each of the following terms that, when taken together, collectively define what is considered a "natural gas transmission pipeline" under Subpart W: "facility with respect to the onshore natural gas transmission pipeline segment," "natural gas," "onshore natural gas transmission pipeline owner or operator," and "transmission pipeline." *See id.* § 98.238.
[10] *See id.* § 98.230(a)(4) ("Onshore natural gas transmission compression means any stationary combination of compressors that move natural gas from production fields, natural gas processing plants, or other transmission compressors through transmission pipelines to natural gas distribution pipelines, LNG storage facilities, or into underground storage. In addition, a transmission compressor station includes equipment for liquids separation, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compression that is part of onshore natural gas processing plants are included in the onshore natural gas processing segment and are excluded from this segment.").

natural gas storage facilities,[11] and liquefied natural gas ("LNG") storage facilities.[12]

As a result, AGA, APGA, and our members are deeply invested in the Proposed Rule, as well as the ongoing GHGRP rulemakings that will affect the WEC. Our strong interest is demonstrated by our prior comments on the WEC and relevant GHGRP rulemakings over the years. This includes responses by both AGA[13] and APGA[14] to the November 2022 Request for Information ("RFI") to inform EPA's implementation of Section 136 of the Clean Air Act; joint comments on the June 2022 proposed rule to address data quality, consistency, and gaps across the GHGRP as a whole;[15] joint comments on the May 2023 supplement to the 2022 Proposal;[16] and, most recently, joint comments on the August 2023 proposal to revise Subpart W in preparation for WEC implementation, consistent with Section 136(h) of the Clean Air Act.[17] Additionally, AGA has filed comments in every round of Subpart W rulemaking related to the oil and natural gas source category since 2008, and APGA has filed comments in each round of Subpart W rulemaking since the initial Subpart W proposal in 2009. Pursuant to EPA's instructions regarding past comments that stakeholders would like the Agency to consider in this rulemaking,[18] the Associations' most relevant prior submissions are enclosed as attachments to our comments on the Proposed Rule (as noted in bold in the footnote for each key submission).

The Associations and our members have long supported measures for promoting best practices for reducing methane emissions and improving the transparency and accuracy of methane emissions reporting. For example, AGA worked with members to develop a Blowdown Emission Reduction White Paper in 2020 to help share learnings and best practices.[19] AGA and many of our natural gas distribution members were founding participants in EPA's Natural Gas STAR program in 1993, and have remained committed to this voluntary technology and best practices program since its inception. AGA and our members also helped establish the EPA Methane Challenge Program, which calls on participating companies to make commitments via one or both

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[11] *See id.* § 98.230(a)(5) ("Underground natural gas storage means subsurface storage, including depleted gas or oil reservoirs and salt dome caverns that store natural gas that has been transferred from its original location for the primary purpose of load balancing (the process of equalizing the receipt and delivery of natural gas); natural gas underground storage processes and operations (including compression, dehydration and flow measurement, and excluding transmission pipelines); and all the wellheads connected to the compression units located at the facility that inject and recover natural gas into and from the underground reservoirs.").

[12] *See id.* § 98.230(a)(5) ("LNG storage means onshore LNG storage vessels located above ground, equipment for liquefying natural gas, compressors to capture and re-liquefy boil-off-gas, re-condensers, and vaporization units for re-gasification of the liquefied natural gas.").

[13] AGA Comments on Inflation Reduction Act Section 60113 RFI (Jan. 18, 2023), https://www.regulations.gov/comment/EPA-HQ-OAR-2022-0875-0035 (**enclosed as Attachment 1**).

[14] APGA Comments on Inflation Reduction Act RFIs (Jan. 18, 2023), https://www.regulations.gov/comment/EPA-HQ-OAR-2022-0875-0062 (**enclosed as Attachment 2**).

[15] AGA and APGA Comments on June 2022 GHGRP Proposal (Oct. 6, 2022), https://www.regulations.gov/comment/EPA-HQ-OAR-2019-0424-0236 (**enclosed as Attachment 3**).

[16] AGA and APGA Comments on May 2023 GHGRP Supplemental Proposal (July 21, 2023), https://www.regulations.gov/comment/EPA-HQ-OAR-2019-0424-0318 (**enclosed as Attachment 4**).

[17] AGA and APGA Comments on August 2023 Subpart W Proposal (Oct. 2, 2023), https://www.regulations.gov/comment/EPA-HQ-OAR-2023-0234-0418 (**enclosed as Attachment 5**).

[18] *See* Proposed Rule, 89 Fed. Reg. at 5318 ("Commenters who would like the EPA to further consider in this rulemaking comments relevant to this rulemaking that they previously provided on any other rulemaking or request for information . . . must submit those comments to the EPA during this proposal's comment period.").

[19] *See* AGA, Blowdown Emission Reduction White Paper (Aug. 5, 2020), https://www.aga.org/wp-content/uploads/2022/12/aga-blowdown-emissions-reduction-white-paper-final-8.5.20.pdf.

of the following options: (1) implementing one or more of EPA's recommended Best Management Practices for reducing methane emissions across company operations, and/or (2) reducing methane emissions to target rates established by the Our Nation's Energy ("ONE") Future Coalition. All of the founding natural gas distribution participants in the Methane Challenge are AGA member companies. Additionally, over the past 30 years, APGA members have participated in the Natural Gas STAR Program (launched in 1993) and subsequently in the Methane Challenge Program (launched in 2016), demonstrating their commitment to taking meaningful actions to reduce methane emissions.

The methane emissions strategies that AGA and APGA members have shared in Natural Gas STAR and the commitments they have made in the Methane Challenge Program have helped to reduce methane emissions from U.S. natural gas distribution systems by 70 percent from 1990 to 2021.[20] This brought the natural gas distribution segment's methane emissions down to 0.12 percent of throughput in 2021, based on EPA's 2023 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2021 ("GHG Inventory") and data from the U.S. Energy Information Administration on total natural gas deliveries.[21] LDC emissions have gone down as the natural gas distribution segment has grown in size: there were 1,337,012 miles of natural gas distribution mains in 2021—an increase of 392,855 miles since 1990[22]—and more than one new residential customer signs up for natural gas service every minute.[23] In addition, many AGA and APGA members have made individual pledges to reduce their methane emissions and are working to incorporate process improvements and deploy methane detection and direct-measurement technologies to carry out those pledges. The Associations' members have worked hard over the past several decades to reduce distribution segment emissions while simultaneously growing their customer base,[24] maintaining the reliability of natural gas service, and keeping energy costs affordable. For example, households that use natural gas for heating, cooking, and clothes drying save an average of $1,132 per year compared to homes using electricity for those applications.[25]

The Associations and our members are also seeking to reduce methane emissions from our upstream suppliers by improving the accuracy and transparency of methane reporting. Working with institutional investors and non-governmental organizations, AGA and the Edison Electric Institute ("EEI") developed an Environmental, Social, Governance ("ESG") and Sustainability reporting template tailored to issues relevant to gas and electric utilities, including methane

[20] *See* EPA, 2023 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2021, at 3-95 (Apr. 15, 2023), https://www.epa.gov/system/files/documents/2023-04/US-GHG-Inventory-2023-Main-Text.pdf ("2023 Inventory"). The 2023 GHG Inventory is the most recently finalized version. The 2024 Draft Inventory, which is scheduled to be finalized after to the filing of these comments, states that "[d]istribution system CH_4 emissions in 2022 were 70 percent lower than 1990 levels and 1 percent lower than 2021 emissions." EPA, 2024 Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2022, at 3-95 (Feb. 14, 2024), https://www.epa.gov/system/files/documents/2024-02/us-ghg-inventory-2024-main-text.pdf ("Draft 2024 GHG Inventory").

[21] *See* AGA, Understanding Greenhouse Gas Emissions from Natural Gas – EPA 2023 Inventory (1990–2021) at 18 – Table 9 (Aug. 15, 2023), https://www.aga.org/wp-content/uploads/2023/10/AGA-Report_Understanding-GHG-Emssions-from-Natural-Gas_2023.pdf.

[22] 2023 GHG Inventory at 3-95. The Draft 2024 GHG Inventory updates this statistic: "There were 1,352,384 miles of distribution mains in 2022, an increase of 408,227 miles since 1990." Draft 2024 GHG Inventory at 3-95.

[23] AGA, Natural Gas: Advancing America – 2024 Playbook at 2 (Feb. 21, 2024), https://playbook.aga.org ("2024 AGA Playbook").

[24] 2024 AGA Playbook at 2 ("More than one new residential customer signs up for natural gas service every minute, and approximately 60 businesses begin new natural gas service every day.").

[25] 2024 AGA Playbook at 11.

emissions.[26] To encourage upstream suppliers to publicly disclose their methane emissions in a robust and comparable way, AGA and EEI also developed the Natural Gas Sustainability Initiative ("NGSI") Methane Emissions Intensity Protocol ("Protocol").[27] The NGSI Protocol provides comprehensive methane intensity metrics for five segments of the natural gas supply chain: (1) onshore production, (2) gathering and boosting, (3) processing, (4) transmission and storage, and (5) natural gas distribution. By publicizing their NGSI methane intensity—a measure of methane emissions relative to natural gas throughput—companies can be recognized for their leadership, which provides a strong incentive for companies across the natural gas supply chain to reduce their methane emissions. Furthermore, non-member companies are free to use the Protocol and its accompanying segment-specific templates, as we have made them available to the general public at no cost.

The ESG/Sustainability template and NGSI are designed to be complementary to other efforts to reduce methane emissions and work in concert with regulatory standards. Ensuring that methane emissions from the natural gas supply chain are minimized is a critical part of our members' efforts to decarbonize. Version 3 of the ESG/Sustainability template, which is the most recent version, is based on emissions and sources reported to EPA under Subpart W of the GHGRP. Similarly, NGSI relies heavily on the default emission factors in the Subpart W rule, augmented by the emission factors EPA uses in the GHG Inventory. Once EPA finalizes its revisions to Subpart W, these regulatory changes will be incorporated into the NGSI Protocol and its templates.

APGA's members formalized their commitment to reduce methane emissions through the APGA Commitment to Environmental Stewardship.[28] The commitment contains ten actionable elements intended to aid methane emission reduction by publicly and community-owned gas systems. These include incorporating best practices for methane emission mitigation at metering-regulating stations and city gate stations where appropriate and feasible, and replacing aging infrastructure that is known to have a higher probability of methane leaks.[29]

In states and communities that recognize and allow certified natural gas, the Associations' members are taking action to reduce the carbon intensity of their delivered product by acquiring natural gas that has been certified as meeting stringent emission standards by independent third-party auditors. The number of new innovative certification products has expanded rapidly in the last several years. For example, in December 2020, Rocky Mountain Institute and Systemiq announced a new certified low-methane gas standard called MiQ ("Methane Intelligence"),[30] which incorporates the NGSI methane intensity metric for the production segment coupled with monitoring on a semi-annual or quarterly basis to detect and fix any higher-emitting sources.[31] There also are other certified lower-methane gas programs, including Equitable Origin's EO100™

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[26] *See* AGA and EEI ESG/Sustainability Templates, https://www.aga.org/research-policy/natural-gas-esg-sustainability (last accessed Mar. 17, 2024).
[27] *See* AGA and EEI Natural Gas Sustainability Initiative, https://www.aga.org/research-policy/natural-gas-esg-sustainability/natural-gas-sustainability-initiative-ngsi (last accessed Mar. 17, 2024).
[28] *See* APGA Press Release: APGA Members Are Committed to Environmental Stewardship (Aug. 3, 2021), https://www.apga.org/viewdocument/apga-members-are-committed-to-envir.
[29] *See* APGA, Excellence in Excellence in Environmental Stewardship Award, https://www.apga.org/programs/awards/environmental-sustainability-award (last accessed Mar. 17, 2024).
[30] *See* MiQ, https://miq.org (last accessed Mar. 17, 2024).
[31] MiQ has incorporated the NGSI Protocol into its standards for several natural gas industry segments.

Standard for Responsible Energy Development[32] and Project Canary's Responsibly Sourced Gas ("RSG").[33] An increasing number of producers have announced that they are obtaining third-party certification under these standards to offer lower-methane intensity natural gas.

The Associations' commitment to reducing methane emissions throughout the natural gas value chain while increasing transparency in disclosure of our industry's GHG emissions is both well demonstrated and unwavering. Our members support measures to decrease GHG emissions and increase disclosure from upstream segments, both of which are essential to having each segment take responsibility for its own emissions. The Associations support the IRA's goals of incentivizing and achieving emission reductions, and we welcome the opportunity to collaborate with EPA to achieve them.

II. STATUTORY BACKGROUND

The IRA amended the Clean Air Act to add new Section 136, titled "Methane Emissions and Waste Reduction Incentive Program for Petroleum and Natural Gas Systems" and codified at 42 U.S.C. § 7436. As relevant to the Proposed Rule, Section 136(c) directs EPA to "impose and collect a charge on methane emissions that exceed an applicable waste emissions threshold" (*i.e.*, the WEC) from facilities that report more than 25,000 metric tons of carbon dioxide equivalent ("$mtCO_2e$") per year under Subpart W of the GHGRP.[34] Section 136(d) identifies facilities in nine of the ten industry segments that report under Subpart W as "applicable facilities" subject to the WEC; natural gas distribution, as the segment is defined in Subpart W, is the only segment not subject to the WEC.[35]

Section 136(e) establishes the amount of the WEC, which must be calculated by multiplying the following dollar amounts by metric tons of methane waste emissions reported under Subpart W for each year: $900 for 2024, $1,200 for 2025, and $1,500 for 2026 and beyond.[36] Section 136(f) establishes the threshold for determining the metric tonnage of methane emissions that is considered "waste" when calculating the WEC.[37] As relevant to the natural gas value chain: for production, waste emissions are those that exceed 0.20 percent of the natural gas sent to sale from an applicable facility; for processing, LNG storage, LNG import or export, and gathering and boosting facilities, waste emissions are those that exceed 0.05 percent of the natural gas sent to sale from or through a facility; for transmission compression, underground storage, and transmission pipelines, waste emissions are those that exceed 0.11 percent of the natural gas sent to sale from or through the facility.

Section 136(f) also provides several mechanisms for applicable facilities to reduce or eliminate their WEC obligations. Applicable facilities under common ownership or control have the option of "netting" their emissions, including those facility emission levels that are below the

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[32] *See* Equitable Origin, EO100™ Certification Process, https://energystandards.org/eo100-certification-process (last accessed Mar. 17, 2024).
[33] *See* Project Canary, Responsibly Sourced Gas, https://www.projectcanary.com/next-gen-energy/responsibly-sourced-gas (last accessed Mar. 17, 2024).
[34] 42 U.S.C. § 7436(c).
[35] *Id.* § 7436(d).
[36] *Id.* § 7436(e).
[37] *Id.* § 7436(f).

applicable thresholds, which would reduce the facilities' collective total WEC obligation.[38] Applicable facilities in the production segments are exempt from the WEC if their waste emissions are caused by unreasonable delay in "environmental permitting of gathering or transmission infrastructure necessary for offtake of increased volume as a result of methane emissions mitigation implementation."[39] Subject to certain conditions, applicable facilities are exempt from paying the WEC if they are in compliance with the recently promulgated new source performance standards ("NSPS") and emission guidelines ("EGs") for methane emissions from new and existing oil and gas facilities pursuant to Section 111 of the Clean Air Act.[40]

Section 136(g) mandates that the WEC be imposed starting with emissions reported for calendar year 2024.[41] Section 136(h) requires EPA to revise Subpart W by August 16, 2024, to ensure that both GHG reporting and the calculation of WEC obligations "are based on empirical data, . . . accurately reflect the total methane emissions and waste emissions from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data" to demonstrate the extent to which the WEC is owed.[42] EPA issued its proposed Subpart W revisions in August 2023,[43] and is aiming to issue a final rule in April 2024.[44] As of the date of these comments, the final Subpart W rule is still undergoing interagency review by the White House Office of Management and Budget.

III. COMMENTS

The Associations' comments on the Proposed Rule highlight key policy implications of the WEC on the natural gas distribution segment, seek clarification about several proposed provisions of particular concern to AGA and APGA members, and make recommendations for improving the WEC rulemaking. We thank EPA for considering our comments.

A. WEC costs from upstream segments should not be passed downstream.

AGA and APGA's primary concern with the Proposed Rule is that upstream segments may pass their WEC costs downstream, potentially compounding along the natural gas value chain until the accumulated obligations of the entire industry's WEC compliance are passed down to the final Subpart W segment: natural gas distribution. LDCs should not be financially responsible for upstream segments that do not reduce their methane emissions below the applicable waste emission thresholds. The IRA set up the WEC program to be an incentive for emission reduction, which will not work if upstream segments pass these costs downstream. Costs must be borne by the emitting party if the WEC has any chance of succeeding as an emission-reduction tool and forging new environmental progress in the upstream oil and natural gas sectors. Congress expressly excluded the natural gas distribution segment from the WEC, therefore it should not fall

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[38] *Id.* § 7436(f)(4).
[39] *Id.* § 7436(f)(5).
[40] *Id.* § 7436(f)(6). The final Methane NSPS/EGs were published in the *Federal Register* subsequent to the publication of this Proposed Rule. *See* 89 Fed. Reg. 16,820 (Mar. 8, 2024).
[41] *Id.* § 7436(g).
[42] *Id.* § 7436(h).
[43] Subpart W Proposal, 88 Fed. Reg. 50,282 (Aug. 1, 2023).
[44] *See* White House Office of Management and Budget, Fall 2023 Unified Agenda of Regulatory and Deregulatory Actions, RIN 2060-AV83, https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202310&RIN=2060-AV83.

on LDCs to ultimately pay the upstream WEC obligations. The responsibility for paying WEC costs should fall on each affected facility.

B. The final rule should make clearer that the natural gas distribution segment is excluded from all aspects of the WEC program.

As EPA recognizes in the Proposed Rule, Section 136(d) of the Clean Air Act defines an "applicable facility" as a facility in "nine of the ten industry segments subject to subpart W, as currently defined in 40 CFR 98.230 (excluding natural gas distribution)."[45] The Proposed Rule is not inconsistent with Section 136(d) on this point; however, there is room in both the regulatory text and preamble to add clarity for facilities that are evaluating whether they may be regulated under the WEC program. The Associations believe there are certain WEC elements where EPA needs to make clearer that natural gas distribution segment emissions are not part of the WEC program, consistent with the intent of Congress in enacting the IRA. The following is a non-exhaustive list of the kinds of clarifications that the Associations encourage EPA to make throughout the final rule.

1. Example NAICS Codes in Table 1.

Table 1 to the Proposed Rule lists several North American Industry Classification System ("NAICS") codes that may be affected by the WEC.[46] The table includes Code 221210, which uses "[n]atural gas distribution facilities" as an example of an affected facility. EPA states that Table 1 is neither exhaustive nor determinative of WEC applicability. Despite this disclaimer, without further explanation, the inclusion of Code 221210 creates avoidable confusion about WEC applicability for the natural gas distribution segment. This is because the NAICS definition of "natural gas distribution" is much broader than the Subpart W definition of the same, shown below:

Comparison of "Natural Gas Distribution" Definitions	
NAICS Code 221210[47]	**GHGRP Subpart W[48]**
"This industry comprises: (1) establishments primarily engaged in operating gas distribution systems (e.g., mains, meters); (2) establishments known as gas marketers that buy gas from the well and sell it to a distribution system; (3) establishments known as gas brokers or agents that arrange the sale of gas over gas distribution systems operated by others; and (4) establishments primarily engaged in transmitting and distributing gas to final consumers."	"Natural gas distribution means the distribution pipelines and metering and regulating equipment at metering-regulating stations that are operated by a Local Distribution Company (LDC) within a single state that is regulated as a separate operating company by a public utility commission or that is operated as an independent municipally-owned distribution system. This segment also excludes customer meters and regulators, infrastructure, and pipelines (both interstate and intrastate) delivering natural gas directly to major industrial users and farm taps upstream of the local distribution company inlet."

[45] Proposed Rule, 89 Fed. Reg. at 5323.
[46] *Id.* at 5319.
[47] U.S. Census Bureau, 2022 North American Industry Classification System Definition for 221210 Natural Gas Distribution https://www.census.gov/naics/?input=221210&year=2022&details=221210 (last visited Mar. 18, 2024).
[48] 40 C.F.R. § 98.230(a)(8).

The Associations ask EPA to specifically call out the fact that the NAICS definition of "natural gas distribution" is broader than the Subpart W definition, the Subpart W definition is the one that is relevant to WEC applicability, and Section 136(d) excludes the Subpart W-defined natural gas distribution segment from the WEC.

2. *WEC Applicability Determination.*

The Associations encourage EPA to make clearer throughout the proposed regulatory text, the preamble, and other EPA guidance that natural gas distribution as defined in Subpart W is completely outside of the scope of the WEC applicability determination. Specifically, the following straightforward explanation from the preamble should be more readily apparent when stakeholders are reading the regulatory text and related guidance: "[O]nly facilities which both fall within one or more of the nine CAA section 136(d) industry segments and report more than 25,000 mt CO_2e under subpart W are subject to the WEC program."[49] Given the complexity of the WEC regime—which requires layered coordination across several Clean Air Act programs—it would be helpful if fewer cross-references were implied in the text. The Associations offer the following examples of clarifications EPA should consider, shown below in track-changes style:

Proposed § 99.2 Definitions.

Applicable facility means a facility within one or more of the ~~following~~ **nine** ~~industry~~ **applicable** segments, as **defined in this section**~~, those industry segment terms are defined in § 98.230 of this chapter~~. In the case where operations from two or more ~~industry~~ **applicable** segments are co-located at the same part 98 reporting facility, operations for all co-located **applicable** segments constitute a single *applicable facility* under this part**.**~~:~~ **An *applicable facility* does not include any industry segment that is not an applicable segment as defined in this section.**

***Applicable segment* means one of the following industry segments, as those industry segment terms are defined in § 98.230 of this chapter:**

(1) Offshore petroleum and natural gas production.
(2) Onshore petroleum and natural gas production.
(3) Onshore natural gas processing.
(4) Onshore natural gas transmission compression.
(5) Underground natural gas storage.
(6) Liquefied natural gas storage.
(7) Liquefied natural gas import and export equipment.
(8) Onshore petroleum and natural gas gathering and boosting.
(9) Onshore natural gas transmission pipeline.

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WEC applicable facility means an applicable facility, as defined in this section, for which the owner or operator of the part 98 reporting facility reports GHG emissions under part 98, subpart W of this chapter of more than 25,000 metric tons CO_2e **per year**. **Only emissions reported for an applicable segment, as defined in this section, shall be included when determining whether a facility is a *WEC applicable facility*.**

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[49] Proposed Rule, 89 Fed. Reg. at 5330.

The term "applicable segments" is used in Section 136(f)(4) to refer to the list of nine industry segments in Section 136(d). Accordingly, the addition of "applicable segment" as a defined regulatory term would be consistent with the statute and provides a streamlined way to add clarity throughout the WEC regulations. Having a regulatory definition for "applicable segment" would also allow EPA to succinctly add needed clarification throughout the preamble and other guidance documents. For example, consider the Associations' proposed edits to the following preamble excerpt that currently sows confusion for LDCs about whether their Subpart W-reported emissions are part of the WEC applicability analysis:

> "CAA section 136(d) defines an applicable facility as one 'within' the nine industry segments subject to the WEC and does not specify that an applicable facility is in one and only one ~~industry~~ **applicable** segment. The EPA understands this to mean that an applicable facility constitutes an entire subpart W facility, including those that report under more than one **applicable** segment. Thus, based on the statutory text, the EPA proposes to assess WEC applicability based on the entire subpart W facility's emissions **from applicable segments**."
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> 89 Fed. Reg. at 5324.

Finally, EPA should revise its ancillary guidance documents to mirror the order of operations of the WEC regulatory text. This will be more helpful for facilities going through the WEC applicability analysis—particularly LDCs with some facilities that may be WEC applicable and others that are excluded. For example, consider EPA's flowchart graphic titled "Steps for Determining Waste Emissions Charge Applicability and Obligation."[50] The first step in the graphic is to determine whether your facility reports total GHG emissions greater than 25,000 mtCO_2e per year under Subpart W. However, as shown above, the regulatory definitions in Proposed § 99.2 require a facility to first determine whether it is an "applicable facility" (*i.e.*, whether it is in one of the nine applicable Subpart W segments) before it determines whether it is a "WEC applicable facility" (*i.e.*, an applicable facility that reports more than 25,000 mtCO_2e annually under Subpart W). The steps in the graphic should follow the same order as the regulatory text so stakeholders may use this guidance to help them better understand the WEC regulations.

3. Calculation of Facility Applicable Emissions.

Each calculation leading up to, and including, the calculation of what EPA proposes to call "facility applicable emissions"[51] that includes Subpart W-reported data as an input should specify that it is Subpart W data reported for one of the nine specified industry segments (*i.e.*, what the Associations are proposing to define as "applicable segments"). For example, the calculation of "facility applicable emissions" in Equation B-6 includes the following input: "$E_{SubpartW,CH4}$ = The annual methane emissions for a WEC applicable facility, as reported under part 98, subpart W of

[50] EPA, Steps for Determining Waste Emissions Charge Applicability and Obligation (Jan. 2024), https://www.epa.gov/system/files/documents/2024-02/wec-applicability-steps-graphic.pdf.

[51] *See* Proposed § 99.2 ("*Facility applicable emissions* means the annual methane emissions, as calculated in § 99.21, associated with a WEC applicable facility that are either equal to, below, or exceeding the waste emissions threshold for the WEC applicable facility prior to consideration of any applicable exemptions.").

this chapter for the corresponding reporting year, mt CH_4."[52] Equation B-6 should clarify that these are annual methane emissions as reported under Subpart W *for an applicable segment*.

EPA should similarly revise explanatory preamble language about these calculations. For example, consider the following excerpt: "The EPA proposes to interpret 'reported metric tons of methane emissions' to mean all reported methane emissions from a facility, as reported under subpart W. This value is an input to equation B–6."[53] On its face, the phrase "all reported methane emissions from a facility, as reported under subpart W" does not exclude natural gas distribution emissions; however, under Section 136, natural gas distribution emissions are not part of the WEC calculations. This clarification is crucial for entities that report Subpart W emissions under one of the nine applicable segments *and* under the natural gas distribution segment. Below is another preamble excerpt with the Associations' recommended edits:

> "Specifically, for facilities that report to multiple ~~industry~~ **applicable** segments under a single subpart W facility, we are proposing in 40 CFR 99.20(e) that the facility-level waste emissions threshold is determined as the sum of the waste emissions thresholds for each ~~industry~~ **applicable** segment that the facility operates within."
>
> 89 Fed. Reg. at 5327.

The Associations would like to reiterate that these comments are not intended to be an exhaustive list of the areas where we would appreciate additional clarification. Rather, these are examples of the kinds of clarifications we hope EPA will aim to make throughout the final rule and related guidance documents.

C. The final rule should clarify that Subpart W emissions are the only GHGRP emissions relevant to WEC applicability.

During EPA's technical outreach webinar on January 25, 2024, Agency staff provided a helpful clarification that the Associations hope will be included in the final rule, as it is not readily apparent in the Proposed Rule. EPA staff explained that a facility is not a WEC applicable facility if it only exceeds the 25,000 mtCO_2e annual threshold by adding its Subpart C combustion emissions to its Subpart W emissions (*e.g.*, a facility with 20,000 mtCO_2e Subpart W emissions and 6,000 mtCO_2e Subpart C emissions is not a WEC applicable facility). The preamble includes a similar explanation about Subpart C emissions in the context of netting,[54] but it would be helpful to have it plainly stated in the context of WEC applicability as well.

This clarification should be broader than only Subpart C. For example, many Subpart W reporters also report emissions under Subpart NN, which applies to natural gas liquids fractionators and local natural gas distribution companies. Additionally, EPA has proposed a new Subpart B

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[52] Proposed Rule, 89 Fed. Reg. at 5375.

[53] *Id.* at 5327.

[54] *See id.* at 5332 ("Other facilities report emissions under multiple subparts (*e.g.*, subpart W and subpart C) and have total emissions equal to or greater than 25,000 mt CO_2e across both subparts, but subpart W emission below 25,000 mt CO_2e. . . . Many of these facilities have total GHGRP emissions exceeding 25,000 mt CO_2e, but subpart W emissions that alone fall below this threshold. We are proposing that subpart W facilities with subpart W emissions equal to or below 25,000 mt CO_2e are not WEC applicable facilities and are therefore excluded from netting.").

that would require reporting the quantity of metered electricity and thermal energy purchased by a facility, which would apply to all facilities that report their direct emissions under other GHGRP subparts.[55] The Associations oppose the addition of Subpart B, as we believe such data collection is outside of EPA's authority.[56] However, if Subpart B is added to the GHGRP, its data should not be included in any WEC-related calculations or determinations.

D. EPA should remove its "four groups" terminology from the preamble.

The Associations are concerned that EPA's preamble excerpt about "four groups" of applicable segments could be misinterpreted as an attempt to limit the statutory flexibility of the netting mechanism under Section 136(f)(4).[57] While it is true that Section 136(f) effectively creates four groups of waste emissions thresholds, the "group" unit has no statutory or regulatory importance to the operation of the WEC program. Each applicable segment has a specified waste emissions threshold calculation, and it just so happens that some segments share the same calculation. The segments in each "group" are no more interrelated for purposes of the WEC analysis than any of the other segments.

When EPA discusses "four groups" in the context of the preamble section on netting, it gives the impression that the Agency may be trying to limit the netting option such that it would apply only within each such "group." This interpretation would be blatantly contrary to the statute, which allows netting "within and across *all* applicable segments identified in subsection (d)."[58] Furthermore, EPA does not use the "four groups" terminology anywhere else in the preamble or the proposed regulatory text. For avoidance of doubt, the Associations recommend that the Agency remove this unnecessary concept from the preamble.

E. EPA should revise the proposed throughput metric for calculating onshore natural gas transmission pipeline methane intensity.

As proposed, the input for throughput data in Equation B-4 will overstate the methane intensity for some onshore natural gas transmission pipelines. To remain consistent with the IRA's aim of accurately reflecting Subpart W emissions in WEC calculations, EPA should modify Equation B-4 and potentially modify the cross-referenced throughput section in Subpart W.

Section 136(f)(3) describes throughput as the amount of natural gas "sent to sale from or through" a facility.[59] In Equation B-4, the term $Q_{ng,Tran}$ represents throughput, which the Proposed Rule describes as "[t]he total quantity of natural gas that is sent to sale from or through the industry

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55 *See* 2023 Supplemental Proposal, 88 Fed. Reg. 32,852 (May 22, 2023).

56 *See* **Attachment 4**, AGA and APGA Comments on May 2023 GHGRP Supplemental Proposal.

57 *See, e.g.*, Proposed Rule, 89 Fed. Reg. at 5331 ("CAA section 136(f)(4) classes these segments into four groups, and is the only provision to use the term 'applicable segments'. As noted above, CAA section 136(f) establishes a set of requirements determining when and how to impose a charge on those facilities triggered into the program, depending on their industry segment and the amount of methane they emit. It follows that CAA section 136(f)(4)'s reference to 'applicable thresholds' refers to these four group-specific thresholds, and 'applicable segments' refers to the nine segments within the four segment groups. In other words, each group of segments constitutes the 'applicable' segments to their corresponding applicable threshold. This is important, again because the four groups laid out under CAA section 136(f) include only WEC applicable facilities.").

58 42 U.S.C. § 7436(f)(4) (emphasis added).

59 *Id.* § 7436(f)(3).

segment at a WEC applicable facility in the reporting year as reported pursuant to part 98, subpart W of this chapter."[60] Onshore natural gas transmission pipelines are instructed to use "the quantity reported pursuant to § 98.236(aa)(11)(iv) of this chapter, in Mscf" as the input for throughput. In the rulemaking to revise Subpart W, EPA proposed to make the following addition to § 98.236(aa)(11)(iv), shown here in track-changes style: "The quantity of natural gas **transported through the facility and** transferred to third parties such as LDCs or other transmission pipelines, in thousand standard cubic feet."[61]

For some transmission pipelines, the proposed change to § 98.236(aa)(11)(iv) will fully encompasses their throughput because all of the natural gas that is "sent to sale from or through" the facility is "transferred to third parties." However, for a company that owns the downstream entity that will receive the natural gas throughput "sent to sale from or through" their transmission pipeline, the "transferred to third parties" language makes § 98.236(aa)(11)(iv) an incomplete metric for that pipeline's throughput. This would have the effect of increasing the pipeline's methane intensity because Equation B-6 will undercount the pipeline's natural gas throughput while accurately counting the pipeline's Subpart W-reported emissions. As a result of inaccurately increasing the pipeline's methane intensity, the corresponding WEC obligation (*i.e.*, amount of money owed) will also increase.

The Associations propose that EPA address this issue in either one of two ways. EPA could amend Subpart W at § 98.236(aa)(11) to require onshore natural gas transmission pipelines to report an additional data element, such as "the quantity of natural gas transported through the facility and transferred to entities other than third parties, in thousand standard cubic feet" or "the quantity of natural gas transported through the facility and sent to sale, in thousand standard cubic feet." As shown by EPA's proposal to change some of the confidentiality determinations for Subpart W data elements as part of this WEC rulemaking,[62] the Agency appears willing to make changes to Subpart W to conform to the needs of the WEC program. The Associations believe this change is similarly required for the proper functioning of the WEC program.

Alternatively, EPA has the authority under Section 136(f) to select throughput inputs from data sources other than Subpart W; the statute is clear that emissions data must come from Subpart W reporting, but it does not specify a source for throughput data. For example, EPA could consider using U.S. Energy Information Administration ("EIA") reporting, such as form EIA-176, which summarizes all natural gas transported through a transmission pipeline.[63]

F. The WEC should exempt emissions caused by third-party excavation damages or other damages that are truly outside of a facility's control despite best efforts.

The Associations urge EPA to exempt from the WEC any emissions caused by damages that were completely outside of the facility's control and occurred despite the facility's best efforts

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[60] Proposed Rule, 89 Fed. Reg. at 5374.
[61] Subpart W Proposal, 88 Fed. Reg. at 50,435; *see also* EPA Redline Strikeout for Subpart W Proposal, (July 27, 2023), https://www.regulations.gov/document/EPA-HQ-OAR-2023-0234-0169.
[62] *See* Proposed Rule, 89 Fed. Reg. at 5358.
[63] *See* Form EIA-176, Annual Report of Natural and Supplemental Gas Supply and Disposition, https://www.eia.gov/survey/form/eia_176/form.pdf (last visited Mar. 18, 2024) and accompanying instructions https://www.eia.gov/survey/form/eia_176/instructions.pdf (same).

to avoid it. For example, the Associations are concerned about a potential scenario in which a transmission line is ruptured due to third-party excavation damage and the resulting methane emissions would cause the facility to owe a large and unexpected WEC obligation. Subpart W reporters have to report these emissions even if caused completely by a third party's actions, such the third party's failure to request pipeline locations via their local One Call Program or 811 Center prior to excavation. Third-party excavation damages to buried transmission lines can occur even when facilities implement top-notch public awareness, safety, and maintenance programs. America's natural gas utilities invest an average of approximately $90 million *every day*—and a total of about $33 billion annually—to enhance the safety of natural gas distribution and transmission systems.[64] Unfortunately, despite significant avoidance and mitigation efforts, it is impossible to completely eliminate excavation damages. In those scenarios, there is often nothing more the pipeline owner/operator could have done to prevent a methane release.

When third-party damage or another uncontrollable factor is the cause of a large methane release despite the pipeline's best efforts to avoid or mitigate it, EPA should exempt the facility from paying a WEC obligation for those emissions. This should include not only the removal of that methane release from a facility's WEC applicable emissions, but also the removal of those emissions from the Equation B-6 input for the facility's annual Subpart W-reported emissions—*i.e.*, these emissions should not count toward the 25,000 mtCO_2e annual threshold for WEC applicability. This should be easy to do because, as noted above, facilities are already required to report these releases as part of their annual Subpart W reporting. EPA could work together with the Pipeline and Hazardous Materials Safety Administration ("PHMSA") and the Common Ground Alliance ("CGA")[65] to identify minimum criteria for facilities to be able to demonstrate that (1) a facility made best efforts to prevent these kinds of pipeline damages; and (2) despite these best efforts, the methane release was truly unavoidable for the facility because it was caused by the actions of a third party or other uncontrollable factor. Based on this criteria, the facility would include information in their WEC filing to demonstrate which emissions they excluded from their WEC calculation. If EPA—in consultation with PHMSA—determines that it needs more information before it can verify the facility's filing, the facility can provide that information in a revised WEC filing pursuant to the procedures in Proposed § 99.7(e).

G. EPA should evaluate whether low-emitting natural gas facilities that provide essential functions for LDC operations can be excluded from the WEC.

As noted throughout these comments, it is clear from the text of Section 136 of the Clean Air Act that Congress intended to exclude the natural gas distribution segment from the WEC program. The Associations encourage EPA to consider whether additional natural gas equipment with low methane emissions, such as peak-shaving plants or underground storage, can be excluded from the WEC when such equipment is a key part of a facility's natural gas distribution system.

For example, some LDCs have peak-shaving facilities that allow them to liquefy natural gas and store it when customer demand is low, then regasify the LNG and inject it into the distribution system when customer demand is high (*i.e.*, at its peak), such as during severe weather

[64] 2024 AGA Playbook at 20.

[65] The CGA is a member-driven association focused on preventing damage to underground utility infrastructure in every aspect of the underground utility industry—including natural gas transmission and distribution. Both AGA and APGA are members of the CGA. Please visit www.commongroundalliance.com for more information.

events.[66] Peak-shaving plants are an important tool for maintaining the reliability of natural gas service, which LDCs have an obligation to provide to their customers. These plants are often located inside the LDC custody transfer station (sometimes called the "city gate") such that LDCs consider them part of the distribution system, they have much smaller capacity than their LNG import/export counterparts, and—of particular importance in the WEC context—peak-shaving plants are very low GHG emitters.[67] The same is true of some underground natural gas storage facilities owned or operated by LDCs. Accordingly, the Associations request that EPA evaluate the feasibility of excluding LDCs' low-emitting natural gas assets from the WEC program while remaining consistent with Congress's directives in the IRA.

H. EPA's interpretation of the Section 136(f)(6) regulatory compliance exemption is overly restrictive.

The Associations agree with the comments submitted by the Interstate Natural Gas Association of America ("INGAA") regarding EPA's proposed implementation of the exemption for regulatory compliance with the methane NSPS/EGs pursuant to Section 111 of the Clean Air Act.[68] Specifically, the Associations agree with INGAA that the Section 136(f)(6) regulatory compliance exemption should be available on a state-by-state basis rather than requiring all standards and state programs to be in place, and that the exemption should only be lost if there are substantive compliance issues—not merely minor deviations.

In addition, the Associations believe EPA is overcomplicating its implementation of the regulatory compliance exemption by reading unnecessary restrictions into Section 136(f)(6)(A)(ii). Nothing in the statutory text requires EPA to wait until all requirements are approved and in place before making its determination that compliance "will result in equivalent or greater emissions reductions as would be achieved by the proposed rule of the Administrator entitled 'Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review' (86 Fed. Reg. 63110 (November 15, 2021)) if such rule had been finalized and implemented."[69] EPA's review of each state plan submittal must be governed by the same criteria: the emission guidelines for methane emissions from existing oil and natural gas facilities that EPA promulgated under Section 111(d) of the Clean Air Act. If a state plan does not meet the EGs' criteria, EPA must reject the plan. Thus, EPA should be able to compare the 2021 proposed EGs with the 2024 final EGs *in advance* to determine whether subsequently approved state plans "will result in equivalent or greater emissions reductions." Likewise, EPA can determine in advance whether the 2024 final NSPS is equivalent to or better than the 2021 proposed NSPS.

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[66] *See* PHMSA, LNG Facility Siting (Aug. 12, 2022), https://www.phmsa.dot.gov/pipeline/liquified-natural-gas/lng-facility-siting.

[67] *See, e.g.*, EPA, GHGRP Petroleum and Natural Gas Systems Sector Profile 2011–2022 at 7, Figure 2 (Oct. 5, 2023), https://www.epa.gov/ghgreporting/ghgrp-petroleum-and-natural-gas-systems-sector-profile.

[68] *See* 42 U.S.C. § 7436(f)(6). The final Methane NSPS/EGs were published in the *Federal Register* subsequent to the publication of this Proposed Rule. *See* 89 Fed. Reg. 16,820 (Mar. 8, 2024).

[69] *Id.* § 7436(f)(6)(A)(ii).

IV. CONCLUSION

The Associations offer the foregoing comments to assist EPA in improving the implementation of the WEC program while remaining consistent with Congress's mandate under Section 136 of the Clean Air Act. We appreciate the Agency's consideration of our input and are available as a resource for EPA staff throughout the development of this rulemaking.

If you have any questions, please contact Jen Baseman at jbaseman@aga.org, AGA Deputy General Counsel Tim Parr at tparr@aga.org, or Erin Kurilla at ekurrilla@apga.org.

Respectfully submitted,

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AGA and APGA's Comments on
"Waste Emissions Charge for Petroleum and Natural Gas Systems"
Docket ID No. EPA-HQ-OAR-2023-0434

Attachment 1:
AGA Comments on IRA Section 60113 RFI

AGA
American Gas Association

Submitted via regulations.gov
Docket No. EPA-HQ-OAR-2022-0875

January 18, 2023

U.S. Environmental Protection Agency.
EPA Docket Center
Mail Code 28221T
1200 Pennsylvania Ave., N.W.
Washington, D.C. 20460

RE: AGA's Comments on EPA's Request for Information – Methane Emissions Reductions Incentives and Waste Emissions Charge (Methane Fee) under the Inflation Reduction Act §60113

The American Gas Association ("AGA") appreciates the opportunity to comment on the U.S. Environmental Protection Agency's (EPA) Request for Information (RFI) in this Docket regarding how to implement the methane emissions reduction incentives and waste emissions charge under section 60113 of the Inflation Reduction Act. Under that provision, EPA received $1.55 billion to reduce methane emissions from the oil and natural gas sector by providing financial and technical assistance. Section 60113 also directed EPA to levy a waste emissions charge for methane emissions (or methane fee) from applicable facilities in excess of certain thresholds based on the methane emissions reported under 40 C.F.R. Part 98, Subpart W of EPA's GHG Reporting Rule.

AGA, founded in 1918, represents more than 200 local energy companies that deliver clean natural gas throughout the United States. There are more than 77 million residential, commercial, and industrial natural gas customers in the U.S., of which 95 percent — more than 73 million customers — receive their gas from AGA members. AGA is an advocate for natural gas utility companies and their customers and provides a broad range of programs and services for member natural gas pipelines, marketers, gatherers, international natural gas companies, and industry associates. Today, natural gas meets more than one third of the United States' energy needs.[1]

[1] For more information, please visit www.aga.org.

I. Methane Incentives Program

EPA's RFI Methane Reduction Incentives Question 1 - How to Structure Financial and Technical Assistance to Provide the Greatest Possible Public Health and Environmental Benefit?

AGA Response: Allow Financial Incentives for Gas Utilities to Expand Programs to Reduce Methane Emissions

The financial incentives under EPA's IRA section 60113 program should be structured to include providing opportunities for grants to gas utilities to further their efforts to reduce methane emissions from their gas distribution systems. This should include particularly funding for expanding deployment of advanced leak detection and repairs and reducing emissions from blowdowns prior to repairs.

AGA's GHG Net Zero Pathways for Gas Utilities Study prepared by ICF International and released in 2021 demonstrates that "through the use of a variety of technologies and approaches, gas utilities can achieve net-zero targets and contribute to economy-wide net-zero emissions goals."[2] We are submitting a copy of the study as Appendix A to these comments in Docket EPA-HQ-OAR-2022-0875. The study evaluates four general categories of GHG emission reduction strategies that gas utilities can deploy to achieve net-zero goals.[3] The approach taken by each gas utility will likely vary depending on factors such as differing geography, structure, facilities, and customer base. However, while different company plans will vary as to the degree to which they deploy specific strategies, all will likely include some combination of strategies from all four categories – including technologies and procedures for reducing the gas utility's scope 1 direct methane emissions.

AGA and our members have long worked to develop, refine, and deploy best practices for reducing methane emissions. For example, AGA worked with members to develop a Blowdown Emission Reduction White Paper in 2020 to help share learnings and best practices.[4] AGA and many of our gas distribution members were founding participants in EPA's Natural Gas STAR program in 1993. Members of both AGA and APGA have been committed to this voluntary technology and best practices program for reducing methane emissions for more than 20 years. AGA and our members also helped establish the EPA Methane Challenge program, which calls on participating companies to set challenging best management practice (BMP) goals for reducing methane emissions across their operations. Alternatively, participating companies have set goals for reducing emissions to achieve low methane emissions intensity levels under the ONE Future track of the Methane Challenge Program. All the founding natural gas distribution participants in

[2] Net-Zero Emissions Opportunities for Gas Utilities, https://www.aga.org/wp-content/uploads/2022/02/aga-net-zero-emissions, AGA Comments Appendix A, p, 5.
[3] Id., see p. 9, Exhibit E.s.3.
[4] AGA Blowdown Emission Reduction White Paper (2020).

Methane Challenge are AGA member companies. The methane emissions strategies our members shared in Natural Gas STAR and the commitments they made in the Methane Challenge program have helped to reduce methane emissions from U.S. natural gas distribution systems by 69 percent from 1990 to 2019, down to just 0.1 percent of annual produced natural gas, as shown in the April 2022 GHG Inventory for 1990-2022.[5]

Our members are dedicated to making further progress in reducing methane emissions. As regulated utilities, their expenditures are governed by state utility commissions, and EPA funding could help bolster and supplement those regulatory programs by creating a new avenue for technology advancement. It should be remembered that by state statute, utility commissions are charged with balancing three goals for (1) improving reliability and safety, (2) maintaining affordable rates for customers, and (3) providing a reasonable rate of return for investors. State commissions have authorized utilities to make expenditures typically for the purpose of improving system reliability and safety. Some of those expenditures also have the benefit of reducing methane emissions, for example by replacing cast iron, vintage plastic, and unprotected steel pipe with modern polyethylene (PE) plastic pipe or protected steel pipe. Monitoring and leak repair programs can also help improve reliability and safety while reducing emissions.

AGA members also include small investor-owned gas utility companies and small gas utilities owned by their communities and towns. These smaller utilities and their communities would particularly benefit from access to funds to help them deploy methane reduction technologies and approaches.

EPA could help expand these methane reduction efforts further by ensuring that gas utilities have the opportunity to receive grants and other incentives from the Methane Emissions and Waste Reduction Incentive Program. We urge EPA to do so.

EPA's RFI Methane Reduction Incentives Question 2 – How can EPA ensure the incentives under the Methane Emissions Reduction Incentive Program complement rather than duplicate other federal and state programs?

AGA Answer: This could be handled through the grant application process.

In order to ensure that the incentives are complementary and not overlapping, EPA can ask gas utility grant applicants to explain how the grant funding would allow the utility to expand their methane emission reduction efforts beyond what they would be able to do based on funding already available to them through utility commission-authorized programs or other state or federal programs (including other IRA programs).

[5] *See* AGA's Analysis of the April 2022 Inventory of U.S. Greenhouse Gas Emissions and Sinks (1990-2020): **https://www.aga.org/research/reports/epa-updates-to-inventory-ghg/.**

II. Methane Waste Emissions Charge & Subpart W GHG Reporting Rule Revisions

EPA'S RFI Methane Waste Charge & Subpart W Revisions Questions 1 & 2:

1. What issues should EPA consider related to methane waste emissions charge implementation?
2. What revisions should EPA consider related to GHGRP Subpart W?

AGA Response: AGA believes these two questions are intertwined, as explained below.

Implementation will run more smoothly if the Subpart W revisions and definitions for the methane charge program are clear and if provisions related to the use of empirical data to account for company-specific methane emissions – including for gas distribution -- allow for ongoing innovation and improvement in technology and approaches in this rapidly evolving field.

Section 60113 of the IRA mandates that the EPA impose and collect a charge on methane emissions from the petroleum and natural gas sector, *upstream of gas distribution*, where methane emissions from an applicable facility exceed a pre-determined waste emissions threshold (methane fee).[6] The waste methane emissions charge (or methane fee) starts at $900 per metric ton of methane in calendar year 2024, increasing to $1,000 in 2025, and then topping out at $1,500 in 2026 and later years.

While our members' natural gas distribution operations are excluded from the methane charge under the statute, other gas utility facilities such as intrastate natural gas transmission pipelines, could be subject to the new fee if emissions exceed relevant thresholds after netting a company's facilities as called for in section 60113.

To implement the methane fee program, Congress required EPA to revise Subpart W within two years (by August 16, 2024) to ensure that reporting and calculation of the methane charge *are based on empirical data* to accurately reflect the total methane emissions and waste emissions from the applicable facilities, and to allow owners/operators to submit empirical emissions data to demonstrate the extent to which a charge is owed.

AGA has two requests. AGA asks first that EPA provide clear regulatory definitions in Subpart W to delineate the dividing line between gas "distribution" that is exempt from the methane charge as opposed to gas "transmission" that is potentially subject to the methane charge. The current definition of "distribution" in Subpart W relies on the definition in 49 C.F.R. Part 172, the pipeline safety regulations promulgated by the Department of Transportation (DOT) Pipeline and Hazardous Substance Safety Administration (PHMSA), which in turn defines distribution as a pipeline that is not a "transmission" or "gathering" line as defined by PHMSA's regulations. At

[6] *See* Sec. 60113. Methane Emissions Reduction Program.

the time AGA filed comments on the GHGRP proposed rule, PHMSA had proposed but not yet finalized a revision that would have caused significant confusion. Since then, PHMSA issued a revised final rule with a more workable definition of transmission pipeline. However, further clarification may be needed in the Subpart W definition of distribution to provide a more stable platform for companies to discern which of their facilities are exempt and which may potentially be subject to the methane waste emissions charge.

Our second request with respect to the methane charge is that when EPA crafts the new Subpart W provisions to allow GHG reporters to use empirical data to account for their company-specific methane emissions, EPA should allow flexibility for using an array of technologies so that reporters can select the empirical methodology that is appropriate for the task. To improve data accuracy, we also ask EPA to allow gas distribution reporters to use empirical data such as company-specific measurements and emission factors. EPA should also avoid locking in particular technologies so that the agency can facilitate rather than thwart ongoing innovation and improvement in this rapidly evolving field.

As AGA explained in our October 6, 2022 comments[7] on EPA's June 21, 2022 GHGRP Proposed Revisions, there are now many tools in the methane detection and quantification toolbox, and it is important to pick the appropriate tool or mix of tools for the job at hand. "Advanced mobile detection platform" (AMLD) methodology shows promise for quantifying the overall methane emissions from all leaks from a gas utility's entire system – when deployed with multiple passes of the mobile platform (whether by car, drone, airplane, or satellite) in conjunction with a robust, statistically valid sample of direct measurement data. This opens a new possibility of quantifying the collective methane emissions of a utility's *system-wide* operations across all assets with a high level of certainty. This requires a robust program encompassing multiple data captures and with the AMLD backed up with a robust, statistically valid sample of direct measurement data. AMLD is still relatively costly and sophisticated compared with the traditional leak detection and emission factor method. It also may be difficult to use this system-wide methodology to differentiate emissions from "distribution" (which is exempt from the methane fee) vs. nearby intrastate "transmission" emissions.

AMLD may not be the best tool for quantifying emissions from individual leaks or from specific types of sources, but it can be quite useful for identifying medium and larger-volume nonhazardous leaks so they can be prioritized for repairs. Satellites and drones have also been used for this purpose. Other tools, such as a high-flow sampler or a tracer gas methodology, are usually more accurate for measuring leaks from specific leaks and facilities and can be used to develop company-specific emission factors that are more accurate than national average emission factors. Activity factors based on miles of transmission pipes or equipment numbers do not

[7] AGA-APGA Comments on EPA Proposed Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule, 87 Fed. Reg. 36920 (June 21, 2022), Docket No. EPA-HQ-OAR-2019-0494.

accurately reflect real-life emission reductions. Where possible, reporters should be allowed to develop company-specific activity factors. In sum, EPA should allow companies flexibility to select a methodology that will yield useful, more accurate empirical data.

AGA appreciates the opportunity to comment. If you have any questions, please contact me or Tim Parr, Deputy General Counsel, tparr@aga.org.

Respectfully Submitted,

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AGA and APGA’s Comments on
“Waste Emissions Charge for Petroleum and Natural Gas Systems”
Docket ID No. EPA-HQ-OAR-2023-0434

Attachment 2:
APGA Comments on IRA RFIs

AMERICAN PUBLIC GAS ASSOCIATION

January 18, 2023

Office of Air and Radiation
U.S. Environmental Protection Agency
Office of Air and Radiation
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

Submitted via regulations.gov

RE: Comments Pertaining to Office of Air and Radiation's Implementation of the Inflation Reduction Act

Office of Air and Radiation staff:

The American Public Gas Association (APGA) appreciates the opportunity to provide comments in response to the U.S. Environmental Protection Agency's (EPA) feedback pertaining to the Office of Air and Radiation's (OAR) implementation of the Inflation Reduction Act (IRA).

APGA is the trade association for more than 730 communities across the U.S. that own and operate their retail natural gas distribution entities.[1] They include not-for-profit gas distribution systems owned by municipalities and other local government entities, all locally accountable to the citizens they serve. Public gas systems focus on providing safe, reliable, and affordable energy to their customers and support their communities by delivering fuel to be used for cooking, clothes drying, and space and water heating, as well as for various commercial and industrial applications.

On August 16, 2022, President Biden signed the IRA, which appropriated almost $11 billion to EPA to implement several provisions of the IRA pertaining primarily to emissions reductions and climate change. As energy providers, APGA member gas systems are environmental stewards, prioritizing sustainability, emissions reductions, and anything that may positively affect their impact on the environment. As OAR works to implement the programs created under the IRA, APGA urges the agency to leverage public utilities, especially the workforce and existing assets, and natural gas more broadly to support the goals of the IRA. To facilitate this, we offer the below comments.

[1] More information available at www.apga.org.

Comments

APGA supports goals to reduce greenhouse gas (GHG) emissions in the United States. As a cost-effective, reliable, and efficient energy source, consumers value the ability to choose natural gas as an energy solution that works best for their budgets and lifestyles. Given its growing domestic supply and safe, reliable, and efficient delivery system reaching almost every home and business in America, the direct use of natural gas is an important part of our country's energy future and a pathway to addressing climate change. In fact, natural gas has been a big driver behind our country's declines in emissions- carbon dioxide emissions from residences using natural gas are about 22% lower than those attributable to a typical all-electric home.[2]

APGA members are committed to continuously improving practices and maintaining their infrastructure to minimize GHG emissions from natural gas distribution systems. To do our part and best support the communities we serve, APGA members are taking action, such as replacing aging infrastructure with modern piping materials to minimize leaks on the system, repairing all leaks as soon as required and practicable, and following industry best practices during construction, operations, and maintenance activities to limit methane emissions.

However, in reaching the ambitious goals of the IRA, APGA cautions against misguided policies that put all our "eggs in one basket" by eliminating Americans' ability to choose the energy source best fit for their needs and budget. Many of the IRA programs for which OAR is requesting feedback do not favor one energy source over another, so APGA encourages OAR to maintain that fuel neutrality as it develops and implements these programs. Every jurisdiction has different resources and needs to serve, so overly prescriptive requirements will preclude many communities from participating in any competitive bidding processes or programs, which might lead to setbacks for our country's decarbonization goals.

To best utilize this money allotted by Congress via the IRA, OAR should keep economic energy savings and carbon reduction front of mind while also allowing eligible entities and partnerships sufficient flexibility to qualify for the competitive funding. Specific responses to select dockets are provided below, and these complete comments have been submitted in each relevant docket.

Docket 2: Transportation Programs

Natural gas also has an important role to play in reducing emissions in the transportation sector. Natural gas vehicles (NGVs) are already some of the cleanest vehicles on the road with significantly lower GHG emissions than those using gasoline or diesel engines, and they have the immediate potential to become even more environmentally friendly with additional support for the development of renewable natural gas (RNG). Blending even small amounts of RNG with fossil natural gas can produce significant emissions reductions, and RNG currently accounts for

[2] American Gas Association, "Natural Gas is Essential for Improving our Environment," https://playbook.aga.org/environment .

more than 53% of all natural gas motor fuel. Because RNG is created by recycling biomethane collected from agricultural waste, landfills, and wastewater treatment plants into a usable product, it has the potential to yield a carbon-negative lifecycle emissions result. Continuing to promote and invest in the development and use of this fuel will only further advance the already existing environmental benefits of NGVs.

NGVs are a cost-effective way to help address excessive pollution from heavy-duty vehicles and ports. Unfortunately, the transportation programs funded under the IRA regarding these areas only provide funding for zero-emission vehicle technology. Focusing only on funding for zero emission technologies imposes unnecessarily high costs and deprives stakeholders of the opportunity to maximize emission reductions by pursuing a variety of commercially available technologies. Commercially available technology that provides reductions of 90 percent or more are readily available at much less cost with more functionality than many zero emission technologies. EPA should work with stakeholders to provide the maximum amount of flexibility as it relates to deploying these technologies and, if necessary, seek Congressional assistance in modifying this overly restrictive statutory language.

Docket 3: Methane Emissions Program

Pipeline safety is the top priority for APGA members and all publicly-owned natural gas distribution systems. The natural gas industry, including APGA members, are also doing their part to reduce emissions from natural gas distribution operations. Overall, the natural gas pipeline network is getting cleaner, as emissions from the U.S. natural gas distribution system have declined 73% since 1990, while more natural gas customers continue to be added every year.

However, publicly owned natural gas systems face unique challenges in obtaining funds to support the accelerated repair and replacement of distribution system infrastructure. Ensuring that public gas systems qualify for direct funding under the Methane Emissions and Waste Reduction Incentive Program will allow APGA members to address numerous Accelerated Actions identified through their Distribution Integrity Management Programs (DIMP). Additionally, qualification for such funding can also allow them to purchase modernized leak detection equipment for their leak detection and repair programs, which will help to further minimize emissions from the distribution sector.

Furthermore, APGA and our members have long supported measures for improving the transparency and accuracy of methane emissions reporting and for promoting best practices for reducing methane emissions. Accordingly, APGA would like to reiterate its previous comments related to revisions to EPA’s GHG reporting program subpart W, as it has yet to finalize recently proposed changes, and several commenters, including APGA, urged the agency to postpone any final changes until IRA-related changes could also be incorporated.[3] Additionally, as it specifically pertains to the IRA, EPA should propose and seek comment on a definition of "empirical data." The proposed definition should recognize that emissions factors are based on empirical data and account for the current and growing number of technologies and methods that can be used to collect emissions data. Furthermore, any revisions to subpart W should make clear that "empirical data" is an *option*, not a requirement, for reporting purposes. Finally, as EPA works to update subpart W, it should also take all efforts to align its requirements to other ongoing and anticipated rulemakings.

Docket 6: Low Emissions Electricity Program & GHG Corporate Reporting

The IRA also authorized funds for EPA "to support— (1) enhanced standardization and transparency of corporate climate action commitments and plans to reduce greenhouse gas emissions; (2) enhanced transparency regarding progress toward meeting such commitments and implementing such plans; and (3) progress toward meeting such commitments and implementing such plans." APGA supports efforts to help bring consistency to this field but cautions the agency against any mandatory reporting. Not only did the IRA not authorize such requirements, but the cost burdens for many entities, such as many APGA members, would be very significant.

* * *

APGA members play a critical role in delivering Americans the clean, affordable, and reliable energy they need. OAR's use of this funding and implementation of these programs should allow states and their communities to leverage the existing natural gas distribution network and fuel delivery infrastructure to meet both the goals of the IRA and the climate goals of the current Administration.

We thank you for the review and consideration of these comments and look forward to continuing to partner with EPA as it develops a path forward. If you have any questions regarding this submission, please do not hesitate to contact us.

Respectfully submitted,

Dave Schryver

Dave Schryver
President & CEO
American Public Gas Association

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[3] Comments from APGA and the American Gas Association to EPA re: Proposed Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule (Oct. 6, 2022), https://www.regulations.gov/comment/EPA-HQ-OAR-2019-0424-0236.

AGA and APGA's Comments on
"Waste Emissions Charge for Petroleum and Natural Gas Systems"
Docket ID No. EPA-HQ-OAR-2023-0434

Attachment 3:
AGA and APGA Comments on
June 2022 GHGRP Proposal

Submitted via regulations.gov
Docket No. EPA-HQ-OAR-2019-0424

October 6, 2022

U.S. Environmental Protection Agency.
EPA Docket Center
Mailcode 28221T
1200 Pennsylvania Ave., N.W.
Washington, D.C. 20460

Re: AGA & APGA Comments on EPA Proposed Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule, 87 Fed. Reg. 36920 (June 21, 2022)

The American Gas Association ("AGA") and American Public Gas Association ("APGA") (jointly, the "Associations") appreciate the opportunity to comment on the U.S. Environmental Protection Agency's ("EPA") Proposed Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule, 87 Fed. Reg. 36920 issued on June 21, 2022 ("Proposed Rule"). Our comments focus on the proposed revisions to the greenhouse gas ("GHG") reporting rules for natural gas facilities under 40 C.F.R. Subpart W.

AGA, founded in 1918, represents more than 200 local energy companies that deliver clean natural gas throughout the United States. There are more than 77 million residential, commercial, and industrial natural gas customers in the U.S., of which 95 percent — more than 73 million customers — receive their gas from AGA members. AGA is an advocate for natural gas utility companies and their customers and provides a broad range of programs and services for member natural gas pipelines, marketers, gatherers, international natural gas companies, and industry associates. Today, natural gas meets more than one third of the United States' energy needs.[1]

APGA is the trade association representing more than 730 communities across the U.S. that own and operate their retail natural gas distribution entities. These include not-for-profit gas

[1] For more information, please visit www.aga.org.

distribution systems owned by municipalities and other local government entities, all accountable to the citizens they serve.

AGA and APGA members operate virtually all the natural gas local distribution systems across all 50 states that are subject to reporting under EPA's current Subpart W reporting rules and that will be directly affected by the proposed revisions to the gas distribution reporting rules. Members of both associations will also be affected by cost impacts on their gas supply due to the proposed revisions of the EPA's Greenhouse Gas Reporting Program ("GHGRP") reporting rules for natural gas transmission pipelines, transmission compression, and underground storage facilities. In addition, AGA members that operate state-regulated intrastate natural gas transmission, transmission compression, liquefied natural gas ("LNG") storage facilities, LNG import-export facilities, and underground storage facilities will be directly affected by the revised reporting requirements for such facilities in the Proposed Rule.

As a result, The Associations and our members have a strong interest in the GHGRP and the Proposed Rule. This strong interest is demonstrated by our participation and comments in past GHGRP and Subpart W Rulemakings. AGA has filed comments in every round of Subpart W Rulemaking relating to the oil and natural gas source category since 2008, and APGA submitted comments in 2009 relating to the initial proposed Subpart W.

The Associations and our members have long supported measures for improving the transparency and accuracy of methane emissions reporting and for promoting best practices for reducing methane emissions. For example, AGA worked with members to develop a Blowdown Emission Reduction White Paper in 2020 to help share learnings and best practices.[2] AGA and many of our gas distribution members were founding participants in EPA's Natural Gas STAR program in 1993. Members of both AGA and APGA have been committed to this voluntary technology and best practices program for reducing methane emissions for more than 20 years. AGA and our members also helped establish the EPA Methane Challenge program, which calls on participating companies to set challenging best management practice (BMP) goals for reducing methane emissions across their operations. Alternatively, participating companies have set goals for reducing emissions to achieve low methane emissions intensity levels under the ONE Future

[2] *See* AGA Blowdown Emission Reduction White Paper (2020).

track of the Methane Challenge Program. All the founding natural gas distribution participants in Methane Challenge are AGA member companies. The methane emissions strategies our members shared in Natural Gas STAR and the commitments they made in the Methane Challenge program have helped to reduce methane emissions from U.S. natural gas distribution systems by 69 percent from 1990 to 2019, down to just 0.1 percent of annual produced natural gas, as shown in the April 2022 GHG Inventory for 1990-2022.[3]

AGA and our members are also seeking to reduce methane emissions from our upstream suppliers through improving the accuracy and transparency of methane reporting. Working with institutional investors and non-governmental organizations ("NGOs"), AGA and the Edison Electric Institute ("EEI") developed an Environmental, Social, Governance ("ESG") reporting template tailored to issues relevant to gas and electric utilities, including methane. To encourage upstream suppliers to publicly disclose their methane emissions in a robust and comparable way, we developed our Natural Gas Sustainability Initiative ("NGSI").[4] NGSI provides comprehensive methane intensity metrics for five segments of the natural gas supply chain: (1) production; (2) gathering and boosting; (3) processing; (4) transmission and storage; and (5) natural gas distribution. By publicizing their NGSI methane intensity, companies can be recognized for their leadership, providing a strong incentive for companies across the natural gas supply chain to reduce methane emissions.

NGSI is designed to be complementary to other efforts to reduce methane emissions and is intended to work in concert with regulatory standards. Ensuring that methane emissions from the natural gas supply chain are minimized is a critical part of our members' efforts to decarbonize. NGSI currently relies heavily on the default emission factors in EPA's Subpart W rule augmented by emission factors EPA uses in the annual EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks ("GHG Inventory").

Additionally, AGA has long advocated for allowing an option under Subpart W to report emissions based on direct measurements and company/utility-specific[5] emission factors, as

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[3] *See* AGA's Analysis of the April 2022 Inventory of U.S. Greenhouse Gas Emissions and Sinks (1990-2020): https://www.aga.org/research/reports/epa-updates-to-inventory-ghg/.
[4] *See* https://www.aga.org/policy/natural-gas-esgsustainability/ (last accessed Sept. 8, 2022).
[5] While most AGA members are investor-owned local distribution companies, APGA members are municipal or publicly owned utilities.

discussed later in these comments. Such an option would allow for more accurate quantification of actual emissions than is currently possible using EPA's default population-based emission factors.

The Associations' members are also taking action to reduce the carbon intensity of their delivered product by acquiring natural gas that has been certified as meeting stringent emission standards by independent third-party auditors. The number of new innovative certification products has expanded rapidly in the last several years. For example, Rocky Mountain Institute ("RMI") and SYSTEMIQ announced a new certified low methane gas standard in December 2020 called MiQ ("Methane Intelligence")[6] that incorporates the NGSI methane intensity metric for production coupled with monitoring on a semi-annual or quarterly basis to detect and fix any higher-emitting sources. There are also other certified lower methane gas platforms, including Equitable Origin's Energy Certification[7] and certification by an equipment vendor's initiative, Project Canary-Trustwell™[8] and its trademarked Responsibly Sourced Gas™ ("RSG"). An increasing number of producers announced in 2021 and earlier this year that they are obtaining third party certification under these standards to offer lower methane intensity natural gas.

APGA's membership formalized their commitment to reduce methane emissions through the APGA Commitment to Environmental Stewardship. The commitment contains ten actionable elements intended to aid methane emission reduction by publicly- and community-owned gas systems. The actions include incorporating best practices for methane emission mitigation at metering and regulation states and city gate stations where appropriate and feasible and replacing aging infrastructure that is known to have a higher probability of methane leaks.

In November 2021, the Bipartisan Infrastructure Legislation introduced a new federal grant program specifically for publicly- and community-owned gas systems. Grant funds are eligible for the purchase or utilization of enhanced leak detection, investigation, and quantification equipment. The 5-year, $1 billion grant program will allow resource constrained municipalities to enhance

[6] *See* https://miq.org/ (last accessed Sept. 8, 2022).
[7] *See* https://energystandards.org/ (last accessed Sept. 9, 2022).
[8] *See* https://www.projectcanary.com/services/responsibly-sourced-gas/ (last accessed Sept. 9, 2022).

their leak detection and repair programs and further their abilities to quantify methane emissions throughout their systems.

The Associations will focus our comments on provisions in the Proposed Rule affecting methane reporting for natural gas distribution facilities and certain other intrastate Subpart W facilities operated by our member natural gas local distribution companies ("LDCs"). We also support the comments filed in this docket on the Proposed Rule by the Interstate Natural Gas Association of America ("INGAA") regarding methane and other GHG reporting for natural gas transmission, storage, and LNG facilities for the reasons stated in INGAA's comments.

Comment Overview

1. **Postpone Finalization of the Subpart W portion of the Proposed Rule:** EPA should instead develop a single Subpart W rulemaking that incorporates changes to implement the new methane fee as Congress required in the Inflation Reduction Act ("IRA").

2. **Provide more time for implementation:** EPA should provide a reasonable time – at least one year after publishing the final rule - to allow reporting entities an opportunity to establish systems to collect data to implement the new reporting requirements under Subpart W.

3. **Use the Lamb Study Emission Factors for Mains and Services, Not the Weller Study:** Proposed revisions to the default population-based emission factors for estimating methane leak emissions from natural gas distribution protected and unprotected steel mains using the Weller Study as justification are not credible, not supported by the record, and would undermine efforts to reduce actual emissions.

4. **Improve and Expand the Option for Direct Measurement for Distribution:** The Associations support EPA's proposals to allow an option for gas utilities to take direct measurements but suggest several improvements that would further the twin goals of obtaining more accurate methane emissions reporting and reducing emissions.

5. **Allow an Option for Using AMLD with Robust Data and Multiple Passes:** The Associations urge EPA to allow an option for using a robust advanced mobile leak

detection (AMLD) program combined with direct measurements to develop company-level emissions quantification for reporting under Subpart W - either through the regular program or through a Best Available Monitoring Methods BAMM 2-year pilot program. The available array of vehicles – cars, drones, planes and/or satellites – should qualify for use in the AMLD option.

6. **Clarify the Definition of "Distribution Pipeline" if PHMSA Fails to Clarify Its Newly Revised Definition of "Transmission Line:** On September 23, 2022, AGA filed a petition for reconsideration of the recently promulgated definition of "transmission line" published by the Department of Transportation ("DOT") Pipeline and Hazardous Materials Safety Administration ("PHMSA") in 49 C.F.R. 192.3. AGA's petition, attached as Appendix A hereto, explains that by adding the phrase "or connected series of pipelines" to the definition of "transmission line," PHMSA has made the definition unconstitutionally vague. If PHMSA does not remove this phrase, its definition of "transmission line" will in turn render EPA's definition of gas "distribution pipeline" void for vagueness due to its reliance on PHMSA's definitions. EPA should urge PHMSA to remove the phrase. If PHMSA does not remove it, EPA will need to clarify its definition of "distribution pipeline" to eliminate ambiguity.

7. **Make the Revisions Requested in INGAA's Comments for Gas Transmission, Storage, and LNG**: The Associations support INGAA's comments regarding EPA's GHG reporting rule proposals for natural gas transmission, underground storage operations, and LNG operations.

Detailed Comments

I. The Associations Recommend that EPA the Subpart W Portion of the Proposed Rule and Develop a New Single Subpart W Proposal that Incorporates Changes Needed to Implement the New Methane Fee as Congress Required in the Inflation Reduction Act.

On August 16, 2022, President Biden signed into law the Inflation Reduction Act (IRA).[9] The IRA mandates the EPA impose and collect a charge on methane emissions from the petroleum and natural gas sector, upstream of gas distribution, where methane emissions from an applicable facility exceed a pre-determined waste emissions threshold (methane fee).[10] The fee starts at $900 per metric ton of methane in calendar year 2024, increasing to $1,000 in 2025, and then topping out at $1,500 in 2026 and later years. While our members' natural gas distribution operations are excluded, other member gas utility operations such as intrastate natural gas transmission pipelines, compression, liquefied natural gas (LNG) peak-shaving storage facilities, and intrastate underground storage could be subject to the new fee. Congress determined that relevant aspects of the program, including *which* facilities are subject to the charge and *how* to calculate the amount of methane subject to the charge, will be based on EPA's GHGRP Subpart W.

To implement the methane fee program, Congress required EPA to revise Subpart W within two years (by August 16, 2024) to ensure that reporting and calculation of the methane charge are based on empirical data to accurately reflect the total methane emissions and waste emissions from the applicable facilities, and to allow owners/operators to submit empirical emissions data to demonstrate the extent to which a charge is owed.

Given this clear direction from Congress, EPA should postpone finalizing the portion of the Proposed Rule related to Subpart W. EPA can finalize other portions of the Proposed Rule and can justify postponing finalization of Subpart W revisions on the rational grounds that Congress mandated additional changes to Subpart W in the Inflation Reduction Act in August 2022, after EPA published the Proposed Rule. Postponement will allow EPA to develop a single Subpart W rulemaking that incorporates changes needed to comply with the Congressional mandate. This later rulemaking can include new requirements that respond directly to the IRA, as well as portions

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[9] *See* https://www.govinfo.gov/content/pkg/BILLS-117hr5376rh/pdf/BILLS-117hr5376rh.pdf.

[10] *See* Sec. 60113. Methane Emissions Reduction Program.

of the Proposed Rule related to Subpart W that EPA deems to be of continued relevance and importance to the program. A single rulemaking will reduce the burden on both industry and the Agency.

Both the Associations and INGAA advocate for improved data quality and quantification, including options for direct measurement, which aligns with Congress's goal of utilizing empirical data. Working through these (often highly complicated) issues in the context of a new rulemaking will provide EPA, regulated stakeholders, and the public at-large the needed time and proper regulatory vehicle to make a single, comprehensive update to GHGRP Subpart W.

The Associations are committed to the goals of the IRA to enhance the accuracy of methane emissions quantification and to incentivize emission reductions and welcome the opportunity to collaborate with the EPA to achieve them.

II. EPA Should Provide a Reasonable Time – At Least One Year After Publishing the Final Rule - to Allow Reporting Entities an Opportunity to Establish Systems to Collect Data to Implement the New Reporting Requirements under Subpart W.

If EPA does not withdraw the Subpart W portion of the Proposed Rule as recommended above, then EPA should allow a reasonable time for implementation. EPA's notice indicates the agency plans to issue a final rule by the end of 2022 and to require affected facility owners and operators to begin collecting data in January 2023 for reports to be filed in 2024. The Associations believe that this aggressive timeline is unreasonable and not feasible. Emission data collection processes at natural gas distribution systems are embedded in larger operations and maintenance procedures. Those procedures can only be modified within often rigorous Management of Change programs. Those programs are deliberately designed to require significant subject matter input and approval by employees or departments impacted by the change. A requirement to immediately modify the data collection procedures after the new requirements are finalized is far from a reasonable expectation. It will not be possible for reporting entities to begin collecting emissions data in January 2023 in response to a final rule issued in the last quarter of 2022. Given the complexity and extensiveness of the proposal, which is likely to be reflected in the final rule, it would not be a reasonable expectation for reporting entities to evaluate the requirements and establish systems to accurately collect the required data elements within such a short period of time.

That task will be further complicated by the interplay of the new methane fee requirements in Clean Air Act (CAA) section 136, recently enacted in the IRA. Section 136 imposes a methane fee based on emissions reported under Subpart W, which adds more complexity. Although emissions during 2023 will not be subject to the methane fee, beginning in 2024, emissions for some sources will be potentially subject to the fee. New section 136 also requires EPA to revise Subpart W to facilitate calculating the methane fee, which adds further uncertainty as to the structure of the final rule.

In addition, EPA has not provided adequate notice and opportunity for reporting entities to evaluate and comment on how portions of the Proposed Rule relate to CAA section 111 methane standards for the oil and natural gas sector that the public has not yet seen. EPA published a notice of proposed rulemaking on Nov. 15, 2021, that was more akin to an *advance* notice of proposed rulemaking, given that it did not include a proposed rule text but only provided a preamble discussion of the changes the agency is contemplating for the new source performance standards (NSPS) and existing source guidelines under to-be-proposed 40 C.F.R. Part 60, Subparts OOOOb and OOOOc. We have yet to see the methane standards proposed rule, let alone the final rule. EPA's methane standards notice in November 2021 indicated that sources inside and including the LDC custody transfer station would not be affected sources, as under the current Subpart OOOOa, but this is unknown until the actual proposed and final rules are made available. Some natural gas distribution utilities also operate state-regulated intrastate natural gas transmission pipelines, natural gas storage facilities, and compressor stations as part of their gas utility systems. A few even operate interstate transmission pipelines. These facilities could be subject to yet unknown requirements under the new methane standards. In the Proposed Rule, EPA proposes to revise "the calculation methodology for equipment leaks in Subpart W so that data derived from…monitoring conducted under NSPS OOOOb or the applicable approved state plan…would be used to calculate emissions."[11] EPA similarly proposes that the Subpart W calculation methodologies will be determined by the yet to be disclosed methane standards rule for Underground Storage facilities, LNG Storage facilities, and LNG Import-Export facilities. There is not sufficient information or notice of these undisclosed calculation methodologies to allow for adequate opportunity to comment. But the uncertainty caused by the scope of this unknown requirement adds further

[11] 87 Fed. Reg. at 36,977.

difficulty for gas utilities trying to understand what is required and to develop and deploy systems and procedures to collect and report emissions data.

Accordingly, the Associations urge EPA to allow at least one year after publication of the final rule to require affected source owners and operators to begin collecting emissions data under the newly revised Subpart W. In other words, the new Subpart W requirements would apply to emissions beginning January of the year that is at least 12 months after publication of the final rule. It would be a more efficient use of company resources to design systems and procedures once, than to chase a moving target of evolving regulatory requirements.

III. EPA's Proposed Revisions to the Default Population-Based Emission Factors for Estimating Methane Leak Emissions from Natural Gas Distribution Protected and Unprotected Steel Mains Are Not Credible, Not Supported by the Record, and Would Undermine Efforts to Reduce Actual Emissions.

A. The Weller Study Does Not Provide a Reasonable Basis for Gas Distribution Emission Factors.

EPA's proposal to blend the direct flow measurements from the Lamb Study[12] with the calculated leak frequency estimates from the Weller Study[13] yields results that are significantly inconsistent with all other previous studies. It is well-known from previous studies and experience that unprotected steel pipe has more leak emissions than modern cathodically protected steel. Both the 1996 GRI-EPA[14] study and Lamb Study demonstrate this emissions differential. Furthermore, EPA's voluntary Methane Challenge program incentivizes natural gas distribution companies or municipal utilities to replace unprotected steel pipe with cathodically protected steel pipe. EPA's Proposed Rule would undermine that incentive because it would establish a higher default emission factor for protected steel than for unprotected steel mains. *See* 87 Fed. Reg. at 36,981-82 (preamble) and proposed Table W-8, at 37,105 (1.2 scf/hr for unprotected steel mains vs. 2.3 scf/hr for protected steel mains).

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[12] Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States | Environmental Science & Technology (acs.org), Lamb et al., *Environ. Sci. Technol.* 2015, 49, 8, 5161–5169, (hereinafter, Lamb Study).

[13] A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems | Environmental Science & Technology (acs.org), Weller et. Al, *Environ. Sci. Technol.* 2020, 54, 14, 8958–8967 (hereinafter, Weller Study).

[14] Harrison et al., GRI-EPA, "Methane emissions from the Natural Gas Industry" (June 1996) (hereinafter, 1996 GRI-EPA Study).

EPA contends both studies have their advantages: the Lamb Study's advantage is its methodology – using direct measurements with a high-volume sampler, and, the Weller Study's advantage is its larger sample size. While the Weller study may have a larger sample size, numerous limitations preclude it from being used as a basis for revisions to the default emission factors for distribution mains. Simply stated, the Weller Study is not a reasonable basis for establishing national default emission factors.

First, and most importantly, the Weller Study conflated cathodically unprotected coated steel in the "coated (protected)" steel emission factor Category and did not verify pipe type, material, or cathodic protection. The Weller Study authors did not obtain information about or verify whether pipe was cathodically protected. As a result, no distinction between cathodically protected and unprotected steel pipe is made. This means leak data for *more leak-prone cathodically unprotected* (but coated) steel is arbitrarily combined in the "coated (protected)" category for calculating emission factors. The Weller Study authors failed to explain why their data indicated more leaks per mile for coated steel pipe than for bare steel pipe. This failure to distinguish cathodic protection is likely a large part of the answer to why the findings in the Weller Study are counterintuitive.

Steel pipe can be protected through cathodic protection and/or coating. Natural gas distribution pipeline operators annually report miles of steel pipe to the DOT PHMSA in four categories: cathodically protected coated pipe, cathodically protected uncoated pipe, coated steel pipe that is not cathodically protected and bare steel that is not cathodically protected. EPA's Subpart W default emission factors for steel pipe account for only two categories: protected and unprotected steel pipe, referring to steel pipe that is or is not cathodically protected.

The Weller Study also did not verify the type of pipe – distribution main or service line. The authors conceded they assumed all emissions to be caused by mains. As the authors explained: "We *assume that the leak indications and emissions observed in these surveys are derived from leaks in the gas mains … [a]lthough some of these leaks may arise from service lines or meter set* *assemblies…*"[15] As a result, main leak factors were inflated because emissions from services were not separated from the emissions assigned to distribution mains.

Verification of pipe material is important, as demonstrated in a recent study conducted by GTI for the California Air Resources Board (CARB) to develop California utility-specific emission factors for mains and service lines.[16] The CARB-GTI Study used a similar data collection and verification method as used in the Lamb Study. Field visits were conducted in the service territories of the three largest natural gas distribution utilities in California, using a high-volume sampler to measure flow rates at leak locations randomly selected from each utility's list of non-hazardous leaks, focusing on (cathodically) unprotected steel mains and services. As in the Lamb Study, pipe type, material and protection were verified.

> *"As part for the study, 78 leak sites were measured above ground. During the leak repairs by the utilities, about 1-3 years later, it was discovered that the original identifications of leak facility [pipe type] (mains vs services) or pipe material (plastic vs steel) were incorrectly classified 59% of the time. The facility and material were misclassified 40% and 31% of the time respectively."*[17]

The methodology of the CARB-GTI Study included an advanced statistical and probabilistic analysis on the leak data and the misclassifications to provide a representation of the average leak rates for underground distribution mains and services by pipe type, material, and protection.[18]

During the Lamb Study, the authors had access to utility pipe material information and were able to verify pipe material, cathodic protection, and location on the main or service line when the utility excavated the pipe after the measurements to conduct repairs. Conversely the authors in the Weller Study were not able to identify the true pipe material and type of leak that was detected (main or service; cathodically protected or not). The Weller Study evaluated four types of pipe material: "bare steel," cast iron, "coated steel," and plastic. Such a categorization is insufficient to draw conclusions from the resulting data about appropriate default emission factors for cathodically protected or unprotected steel pipe. Bare steel pipe is pipe that lacks a coating –

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[15] Weller Study, Section 2.2, p. 8960.

[16] Ersoy, Adamo, "Quantifying Methane Emissions from Distribution Pipelines in California," Final Report (Sept. 2019) ("CARB-GTI Study").

[17] Id. p. 1. *See* also p. 13 and Appendix A.

[18] Id, at p. 1.

but it may not lack cathodic protection. Coated steel may have a coating, but it may lack cathodic protection. *In other words, the Weller Study design at the outset did not actually attempt to provide emissions estimates for protected or unprotected steel pipe*.

In addition, in the Weller Study, other materials were aggregated with one of the other four categories. Copper pipe was included in the bare steel. Ductile iron was combined with cast iron. This lack of proper pipe material characterization in the Weller Study design significantly undermines its value for determining emissions factors for protected and unprotected steel pipe.

Second, the "advanced mobile detection platform" (AMLD) methodology used in the Weller Study shows great promise for the development of system-specific emission factors, but it is not an appropriate tool for assessing emission factors for specific types of pipe material. There are now many tools in the methane detection and quantification toolbox, and it is important to pick the appropriate tool or mix of tools for the job at hand. AMLD can be quite useful when used to identify and fix medium and larger-volume non-hazardous leaks. As discussed later regarding company/utility-level system emissions quantification, AMLD can also be quite useful to quantify overall emissions from all leaks from a company's entire distribution system – when deployed with multiple passes of the mobile platform (whether by car, drone, airplane, or satellite) in conjunction with a robust, statistically valid sample of direct measurement data. However, it is not the best tool for quantifying emissions from individual leaks from specific types of sources, such as distribution mains made of different pipe materials.

The methodology used in the Weller Study was initially developed in field studies as a screening tool to assign distribution leak plume detections to approximate leak rate categories of very low (4 to 9 CH4 g/min.), low (10 to 36 g/min.), medium (37 to 182 g/min.) or high (>182 g/min.) for the purpose of prioritizing repairs for non-hazardous leaks that are relatively higher emitters.[19] Under DOT PHMSA pipeline safety regulations, 49 C.F.R. Part 192, natural gas

[19] Higher emitting leaks in the distribution context are typically orders of magnitude lower than the "super emitters" in upstream operations, such as from stuck dump valves on separation tanks. This is reflected in the relatively low percentage of emissions from gas distribution as compared to other sectors of the natural gas supply chain. For example, EPA's Inventory of GHG Emissions and Sinks (1990-2020) published in April 2022 indicates that emissions from gas distribution in the U.S. contributed only 8.4 % of emissions from the natural gas sector. *See* AGA's analysis in "Understanding the EPA GHG Inventory," p. 9, https://www.aga.org/research/reports/epa-updates-to-inventory-ghg/.

distribution pipeline operators fix hazardous leaks immediately. For safety purposes, leaks that are currently non-hazardous leaks are scheduled for timely repair, and leaks that are determined to have no potential to become hazardous are either repaired within a longer timeframe or placed on a leak log and monitored. However, for purposes of reducing methane emissions to help minimize climate impacts, our members are interested in methods for identifying those non-hazardous leaks that have relatively higher emissions so that these leaks can be prioritized for repairs. Our members have found the methodology used in the Weller Study is useful for that purpose – to categorize non-hazardous leaks into approximate categories of small, medium, and larger emitters. However, our members have found that this methodology is not suited for measuring actual emission flow rates from specific leaks from specific pipe materials.

A field study conducted by NYSEARCH and a large group of natural gas utilities in 2015, with additional validation tests in late 2017 and 2018 compared the results of three AMLD technologies (including two types of cavity ring down spectrometers technologies[20] – one of which was used in the Weller Study – coupled with modeling) with direct measurements of over 300 leaks using a high volume sampler.[21] The goal of the NYSEARCH Study, co-funded by DOT PHMSA, "was to define a process for independent validation of mobile methane emissions measurement technologies."[22] The results showed AMLD – could quantify leaks within very broad ranges, which is useful as a general tool for prioritizing leaks, but for example, not to provide accurate emissions measurements for reporting or inventory purposes to develop emission factors for different pipe materials. "One of the conclusions…was that the technologies that were evaluated had a wide range of accuracy and precision…and] data analysis showed that accuracy of the predicted vs. actual flow rate indicated a 77% accuracy shown to within one order of magnitude."[23] Stated simply, the NYSEARCH Study demonstrates that the AMLD methodology

[20] The AMLD technologies evaluated in the NYSEARCH Study are described in D'Zurko and Mallia, "Measurement Technologies Look to Improve Methane Emissions," Pipeline & Gas Journal (Feb. 2018) at 55, https://pgjonline.com/magazine/2018/february-2018-vol-245-no-2/features/measurement-technologies-look-to-improve-methane-emissions.
[21] https://www.nysearch.org/white-papers/Validation-Methods-for-Methane-Emissions-Quantification-Technologies-Final.pdf (Oct. 2020) (hereinafter NYSEARCH Study).
[22] Id. P. 2.
[23] NYSEARCH Study, p. 1 referencing Figure 1.

is not as accurate as using high volume samplers to measure the flow rate of specific leaks from specific types of pipe materials.[24]

While AMLD is not the best tool for developing population- based emission factors for different types of pipe, the NYSEARCH Study[25] noted that a previous report indicated that with repeated passes, mobile technologies such as AMDL can be useful in quantifying overall system emissions:

> *"Adam Brandt et al (ii) have shown that more frequent surveys of gas systems even with less sensitive detection devices can substantially support methane emissions measurements. NYSEARCH data allows actual implementation of such an approach by defining quantitative uncertainties of mobile leak quantification systems in realistic conditions."*[26]

However, the level of frequent surveying suggested by Adam Brandt et al was not performed for the Weller Study.

Third, the Weller Study has limited data from only four cities, not the 13 cities from across the country in different geographic areas that are included in the Lamb Study. The results from those four cities were extrapolated to construct nationwide assumed emissions rates. This lack of geographic diversity can introduce significant bias. The study also did not consider differences between urban, suburban, and rural areas.

Fourth, the Weller Study exhibited a high degree of uncertainty. The Weller Study showed that the AMLD methodology was unable to document a high degree of correlation between field results and control test results. There were two to three orders of magnitude difference in flow rates between the author's predicted emission rates and confirmed actual emission rates during in-field validation studies. These validation studies were carried out using tracer-ratio methods, enclosure, and high-volume sample methods, and controlled metered releases.

Fifth, the Weller Study did not distinguish between biogenic and thermogenic sources of methane. This means the Weller Study may have included emissions from landfills, wetlands,

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[24] Id.

[25] NYSEARCH Study p. 5.

[26] Id at 5, quoting Chandler E. Kemp, Arvind P. Ravikumar, and Adam R. Brandt "Comparing Natural Gas Leakage Detection Technologies Using an Open-Source "Virtual Gas Field" Simulator" Environ. Sci. Technol. 2016, 50, 4546–4553.

sewers, and other biogenic sources rather than only leaks from the natural gas distribution systems, thereby inflating emissions and leak rates.[27]

Finally, the Weller emission factors derived from the Weller Study are unreliable because the Weller Study methodology used minimal verification for leak locations. During the field campaign, the authors assumed that a leak indication within 40 meters of a pipeline must be a leak associated with the distribution pipeline – considering the wind direction measured at the vehicle. The study design did not consider the possibility of a different wind direction at the actual location of the leak or the effect of obstructions (such as trees or structures) between the vehicle and the actual leak location. These are commonly encountered phenomena for leak detection in the natural gas distribution industry, particularly when using AMLD.

The Weller Study clearly does not provide a rational basis in the rulemaking record for EPA to revise its national default emission factors so that lower-emitting cathodically protected steel mains appear to emit more than cathodically unprotected steel gas distribution mains. Such a revision would undermine efforts to reduce actual emissions by making it appear – inaccurately – that replacing protected steel with unprotected steel would reduce emissions when the evidence shows the reverse is true.

B. To provide more accurate emissions reporting and to incentivize actual methane emission reductions, EPA should adopt the Lamb Study emission factors in the Subpart W Reporting Rule, as it did for the annual national GHG Inventory.

EPA has asked whether it should adopt the emission factors for gas distribution developed in the Lamb Study, which EPA already uses in the annual GHG Inventory, for reporting emissions with default emission factors under Subpart W. The Associations believe this is entirely appropriate because EPA already uses the Lamb Study emission factors in its annual GHG

[27] *See* Weller Study, section 2.2, p. 8960, noting that the authors "used the methane concentration data to develop NG leak indications consisting of the location of a potential leak and an estimate of its size. These data products were derived from the survey data using a set of data-processing algorithms, described in work of Weller et al. 2019." The reference in footnote 19 of the Weller Study leads to section 4.2 of the 2019 Weller et al. study, which states in paragraph 4 of section 4.2: "First, we do not distinguish between thermogenic and biogenic CH4 sources, but this capability could be added by analyzing both CH4 and ethane concentrations. There is no reference to using methane to ethane ratios in the Weller Study published in 2020.

Inventory and because it is the best basis available at present for default national average emission factors.

First, the Lamb Study reduced uncertainty through direct measurements, using a high-volume sampler methodology, which is the appropriate approach for measuring flow rates from leaks and developing emission factors for specific types of pipe materials. The Lamb Study methodology involved delineating the parameters of a leak using standard leak detection technology, covering and sealing the leak area with a tarp, and connecting a high-volume sampler to measure the flow rate of the leak. This is a highly accurate method for measuring leak flow rates, as EPA has recognized by including it in a limited list of proposed direct emissions measurement methods.

Second, the Lamb Study included nationwide data from 13 cities across the country in different climates and with a variety of distribution system configurations more representative of gas utilities nationwide. The distribution systems studied were geographically diverse and included dense urban areas as well as suburban and rural areas. The Lamb Study database of 13 cities is clearly more representative than the Weller Study that only included four cities.

Third, the Lamb Study methodology verified leak locations. Unlike the Weller Study, the Lamb Study verified leak locations before measurement by using standard, reliable leak detection methods to identify the exact area of a leak. This further helped reduce uncertainties.

Fifth, the Lamb Study research team verified pipe material and distinguished between cathodically protected and cathodically unprotected steel pipe. Because operators assisted the authors of the Lamb Study in allowing site access, providing pipe asset and operations information, and following up on leak measurements by excavating the leak locations and conducting repairs, the authors were able to view the pipe, verify the pipe material and the presence or absence of cathodic protection, and report back to the research team. This prevented confusion between cathodically protected and unprotected steel pipe that is a weakness of the Weller Study.

For the foregoing reasons, The Associations urge EPA to adopt the Lamb Study emission factors and leak frequency data – which the agency has already adopted in the annual GHG

Inventory – as the new default population-based emission factors for gas distribution mains and services for Subpart W. This will promote consistency between Subpart W and the GHG Inventory and will improve the accuracy of reported emissions.

C. For Subpart W Reported Data Filed in Previous Years for Distribution Mains and Services, EPA Should Retain the Emission Factors Used in Those Prior Reports to Better Reflect Improving Leak Detection and Repair Practices Over Time.

The Associations request that EPA adopt a practice used in its GHG Inventory to interpret emissions data across the time series of reported data. Namely, when EPA adopts new estimates in the GHG Inventory based on new emissions studies of specific sources, the agency determines whether it is appropriate to apply the new emissions estimate back to 1990or, instead, to use previous emission factors for earlier years and the new emissions data for later years. This practice recognizes that lower emissions estimates are likely due to improving leak detection and repair standards as well as adoption of other emission reduction best practices. EPA's proposed emission factor for cast iron pipe is a case in point. The 1996 GRI-EPA Study used high volume samplers to measure leak flow rates from gas distribution mains and provided a higher emissions rate calculation than was found in the Lamb Study. The lower emissions rate is likely due to the increased application of best practices for leak detection and repair standards that the Associations members have learned through industry best practices workshops and EPA's voluntary Natural Gas STAR and Methane Challenge programs. Accordingly, the more recent Lamb Study emission factors could be appropriately applied to estimate current day emissions and would not require a readjustment to previously reported emissions through the Subpart W program or other voluntary emissions reduction initiatives (such as EPA Natural Gas STAR, EPA Methane Challenge, or individual private sector GHG reduction goal programs) that were based on the original 1996 GRI-EPA Study emission factors.

IV. The Associations Support EPA's Proposals to Allow an Option for Utilities to Take Direct Measurements but Suggest Several Improvements that Would Improve Feasibility and Further the Twin Goals of Obtaining More Accurate Methane Emissions Reporting and Reducing Emissions.

A. EPA's Proposal to Allow an Option for Using Direct Measurement of Leaks in a Gas Utility Facility "Complete Leak Survey" of T-D Should Also Allow Using the Data to Create Company/Utility-Specific Emission Factors for T-Ds and Other Above and Below-Ground M&R.

We are pleased that the agency is proposing an option for reporting entities in the natural gas value chain to conduct direct measurements of leaks using technology such as a high-volume sampler or calibrated bag methodology to allow reporting more accurate emissions data under Subpart W. For the gas distribution sector, the agency is proposing to allow gas utilities to conduct their annual Subpart W survey of transmission to distribution pressure reduction stations (T-Ds) using direct measurements. The Associations believe that this is an improvement over the current method using: (1) an activity count of all leaks (detected at a concentration at or above 10,000 ppm); (2) applying a formula in the rule to calculate an average emission factor per T-D; and (3) multiplying that population-based emission factor by the number of above ground T-Ds and above ground M&R stations in the utility's gas distribution system across a single state.

EPA proposes to continue the practice of requiring a complete facility leak survey, which in the natural gas distribution sector means all the T-Ds in the entire state-wide gas distribution system operated by the same gas utility (what EPA defines as a "facility"). EPA's use of the term "facility" for the distribution sector is unique in that it is not limited to the normal fence line concept of "facility." In the current rule, a gas distribution "facility" is defined to mean "the collection of all distribution pipelines and metering-regulating stations that are operated by a Local Distribution Company (LDC) within a single state that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system." 40 C.F.R. 98.238. Recognizing that some gas utilities have hundreds or even thousands of T-Ds spread throughout a state, EPA has allowed gas utilities to conduct their T-D surveys over multiple years - up to five years - provided the utility surveys a roughly equal number of T-Ds per year. For example, a utility could survey one-fifth of its T-Ds per year over a five-year cycle. Alternatively, it could use a two-year cycle and survey half of its T-Ds per year. EPA should continue to allow spreading this task across more than one year both for traditional Subpart W T-

D surveys and for the new direct measurement option. As direct measurements using a high-volume sampler or calibrated bag are more time consuming, the ability to spread the task across more than one year will be even more important to its feasibility.

In addition, we ask that EPA allow a company to continue using its previous T-D emission factor for the T-Ds not yet subject to direct measurements and to use a blended company/utility emission factor for other metering and regulating stations (M&Rs). This blended emission factor should apply to both above and below ground structures. The Associations recommend that a utility's blended emission rates should be based on the proportion of its T-Ds directly measured versus the T-Ds still using the previous Subpart W survey method until all the T-Ds have gone through a full cycle of surveying using direct measurements.

The Associations also agree with INGAA's comments that when a leak is detected in a Subpart W leak survey and the gas utility has records demonstrating the date it was confirmed to be fixed, EPA should allow the operator to use the date the leak was fixed as its end date. That principal should apply in all industry segments, including gas distribution.

B. The Associations Urge EPA to Allow Company/Utility-Specific Emission Factors Based on Direct Measurements of Gas Mains, Services and Other Distribution Sources to Improve Accuracy and Reward Emission Reductions.

Direct measurements of leaks on gas distribution sources using high volume samplers can provide a more accurate assessment of a company's actual emissions from specific sources than population-based default emission factors. In fact, population-based emission factors (multiplied by miles of pipe or numbers of components or equipment) do not allow a company to demonstrate its actual emission reductions using improved monitoring, leak detection and repair. This inability to demonstrate reductions despite significant cost and effort could undermine what otherwise would be an incentive to achieve greater reductions. Additionally, if a natural gas utility expands its natural gas system to serve more customers or improve reliability, the additional miles of pipe or number of pressure-regulating stations will result in reporting apparent increased emissions of methane – even if actual emissions declined due to the use of best practices and improved materials. In contrast, a leaker-based, utility-specific emission factor that is multiplied by the number of detected leaks provides a more accurate emissions assessment and creates an incentive to reduce leaks in the system. A robust leak detection program can provide assurance of finding any significant “unknown” leaks not already on a utility’s leak log.

EPA is aware of this dilemma, and at least one major environmental organization has publicly expressed support for using direct measurements and technology advancements to improve the detection, quantification, and characterization of methane emissions.[28] In this rulemaking, EPA has an opportunity to promote the use of direct measurement to improve the accuracy of emissions reporting while incentivizing and rewarding emission reductions.

C. As an Alternative to Direct Measurement or Default Emission Factors, EPA Should Allow an Option to Use the Company/Utility T-D Leak Survey Emission Factor from a Traditional Subpart W Leak Survey of T-Ds for Reporting Both Below-Grade T-D and M&R Emissions.

Under the current rule, EPA directs gas utilities to use the emission factor developed in their survey of above-ground T-Ds multiplied by the count of other above-ground metering and regulating equipment to estimate methane emissions from above-ground M&Rs. However, the current rule requires using default national average, population-based emission factors to estimate emissions from below grade T-Ds and other M&Rs that are below grade, with several different emission factors depending on the inlet pressure of the station.

The Proposed Rule would somewhat streamline emission reporting for these below grade sources by using a single emission factor without correlating it to inlet pressure. The agency reasons that the Lamb Study did not find significant differences in emissions between below grade T-Ds or M&Rs with different inlet pressures. The Associations support this reasonable reform but do not think it goes far enough to improve reporting of emissions from below grade sources.

While direct measurement and AMLD campaigns may be feasible for larger utilities, this may be beyond the means of smaller gas utilities, especially those that are operated by small municipalities. Therefore, the Associations request that as an alternative to the proposed combined default national average emission factor for below grade sources or the direct measurement solution discussed above, EPA should allow a gas distribution utility to use its T-D emission factor

[28] *See*, e.g., Testimony of David Lyon, PhD, Senior Scientist, Environmental Defense Fund (EDF), before the House Committee on Science, Space, and Technology (June 8, 2022), Lyon Testimony.pdf (house.gov), p. 4.

for both above and below grade T-Ds and M&Rs. In addition, where a utility follows up a leak detection with repair, the utility should not be required to apply an emission factor that assumes the leak continues for the entire year or until the next T-D Subpart W survey. Instead, the date of documented leak repair should be used as the end point for the leak. Our members are finding that the leak rates are very low for both categories of station. They should be allowed to use their company/utility-specific Subpart W survey T-D emission factor for these M&Rs, regardless of whether they stations are above or below grade.

D. Enhanced OGI Leaker Emission Factors Based on Upstream Data Are Not Representative of Distribution T-D Operations and Should Not Be Used to Revise the Table W-7 Distribution T-D Emission Factors.

EPA proposes to apply larger leaker emission factors for onshore production and natural gas gathering and boosting where optical gas imaging ("OGI") is used to detect leaks, based on upstream studies finding OGI "identifies fewer yet larger leaks than the EPA's Method 21."[29] In addition, EPA proposes to apply these larger OGI leaker emission factors to all downstream sectors, including distribution T-D components, based on the assumption that the upstream data is equally applicable downstream. The Associations agree for the reasons given in INGAA's comments that this is not the case for downstream sectors including natural gas transmission, underground storage, LNG storage, LNG import -export facilities or distribution T-Ds. The Associations urge EPA not to add OGI enhanced leaker emission factors to Table W-7 for T-D components. Moreover, Table W-7 is labeled incorrectly and should refer to leaker emission factors for gas distribution.

V. The Associations Urge EPA to Allow an Option for Using a Robust AMLD Program Combined with Direct Measurements to Develop Company/Utility-Level Emissions Quantification for Reporting Under *Subpart W.*

While AMLD is not the best tool for measuring emission flow rates from individual sources such as a leak on a distribution main, as discussed above, there are promising developments that now open a new possibility of quantifying the collective methane emissions of a utility's *system-wide* operations across all assets with a high level of certainty. This requires a robust program encompassing multiple data captures (whether by vehicle, drone, and/or satellite) with the AMLD

[29] 87 Fed. Reg. at 36976 (preamble), 37105 (proposed revised Table W-7).

backed up with a robust, statistically valid sample of direct measurement data. It is still relatively costly and sophisticated compared with the traditional leak detection and emission factor method, so it is best introduced as an option that well-resourced utilities can opt to pioneer. As the industry gains experience and more utilities participate, economies of scale should help make this method more assessable to smaller gas utilities. Demonstration projects using this methodology are already occurring in the field by AGA members SoCalGas working under the auspices of the California Air Resources Board (CARB), Southern Company Gas based in Atlanta, Georgia, and Duke Energy's Piedmont Natural Gas Division based in North Carolina.

As an example, a recent study by AGA member company Pacific Gas & Electric Company (PG&E) and Picarro, an AMLD vendor, describes a method for using AMLD to quantify gas distribution *system-wide* emissions with a high confidence level. The procedure described in the paper also included fixing large leaks to reduce emissions reductions which were then confirmed in subsequent surveys. A copy of the paper, to be published in the Environmental Science & Technology journal by the American Chemical Society, is attached as Appendix B. It should be noted that there are now several AMLD vendors offering mobile cavity-ring down mass spectrometers or mobile laser spectroscopy technologies, coupled with sophisticated modeling and the ability to differentiate biogenic sources.[30]

In addition, GTI Energy is working with companies across the natural gas value chain, academics, and NGOs in its Veritas initiative to build a consensus segment-specific protocols to reconcile and verify uncertainty levels for bottom-up and top-down measurements and methodologies, including the AMLD and system-wide emissions quantification methodology.[31]

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[30] The Associations are aware of five currently available AMLD systems (listed alphabetically):

1. ABB MobileGuard™ - https://new.abb.com/products/measurement-products/analytical/laser-gas-analyzers/advanced-leak-detection/abb-ability-mobile-gas-leak-detection-system
2. Aeris Responder™ - Acquired by Project Canary in March 2022. -https://aerissensors.com/technology/.
3. Aclima - https://www.aclima.io
4. Heath Discover™ - https://heathus.com/products/discover-advanced-mobile-leak-detection-amld/
5. PICARRO Surveyor™ - https://www.picarro.com/sites/default/files/2017-03/Picarro_Surveyor_Brochure_0.pdf

[31] *See* https://www.gti.energy/veritas-a-gti-methane-emissions-measurement-and-verification-initiative/. The segment-specific Veritas Measurement Protocols are intended to provide a framework for quantitative measurement of methane emissions from sources and discrete sites within each segment of the natural gas value chain from production through distribution. Whole site, whole system, and focused methane measurement technologies are evolving rapidly, and the measurement protocols are not prescriptive in terms of the measurement technologies to be deployed. The Veritas measurement protocol in conjunction with the reconciliation protocol will reconcile measured emissions with emission factor-based inventories.

GTI Energy has announced plans to release the Veritas segment specific protocols in December 2022. This would allow time for companies to deploy systems and procedures to use the protocols for quantifying emissions in 2024 for Subpart W reports to be filed in March 2025. We offer this in response to EPA's request for comments "on alternative methods for quantifying leaks… along with supporting information and data."[32]

In the alternative to including this as an option for regular Subpart W reporting in the first reporting cycle under the revised final rule, should EPA decide against that path at this juncture, then The Associations urge EPA to allow this option through a two-year pilot program under the Best Available Monitoring Methods (BAMM) provisions in Subpart W to allow willing utilities to road-test and improve the emerging company/utility system-level AMLD approach. This would further build the record for adopting this as an option in the regular Subpart W reporting program in EPA's next round of Subpart W revisions.[33]

VI. EPA Should Urge PHMSA to Reconsider and Remove the Phrase "Or Connected Series of Pipelines" from its Revised Definition of "Transmission Line" to Avoid Making EPA's Related Definition of "Distribution Pipeline" Void for Vagueness and Arbitrary and Capricious.

On September 23, 2022, AGA filed a petition for administrative reconsideration of the recently promulgated definition of "transmission line" in a final rule published by the DOT PHMSA on August 24, 2022.[34] The new PHMSA Final Rule revised the definition of "transmission line" in 49 C.F.R. 192.3, which is the basis for EPA's Subpart W definitions pertaining to gas distribution. AGA's petition, attached as Appendix A hereto, explains that by adding the phrase "or connected series of pipelines" to the definition of "transmission line," PHMSA has made the definition void for vagueness under the Due Process Clause of the U.S. Constitution,[35] because a reasonable operator or owner will be unable to determine the scope of its

[32] 87 Fed. Reg. at 36,977.

[33] In the Proposed Rule preamble, EPA also requested comments to obtain "information that may aid in potential future revisions." 87 Fed. Reg. at 36,920.

[34] Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments, 87 Fed. Reg. 52224 (Aug 24. 2022) (hereinafter PHMSA Final Rule).

[35] The vagueness doctrine requires fair notice of what conduct is subject to criminal penalties. *See*, e.g., *Johnson v. United States*, 495 U.S. 575 (2015) (definition of "violent felony" included a residual clause that gave insufficient notice of the consequences of an action); *Sessions v. Dimaya*, 138 S. St. 1204 (2017) (straightforward application of Johnson rendered a residual clause's ill-defined risk threshold unconstitutionally vague).

pipeline facilities that are subject to the regulatory requirements for transmission under the Pipeline Safety Act, which carries potential criminal sanctions for violations. If PHMSA does not remove this phrase upon reconsideration, its definition of "transmission line" will in turn render EPA's definition of gas "distribution pipeline" void for vagueness due to its reliance on PHMSA's definitions. EPA defines "distribution pipeline" in 40 C.F.R. 98.238 to mean "a pipeline that is designated as such by the Pipeline and Hazardous Material Safety Administration (PHMSA) 49 CFR 192.3." PHMSA defines "distribution line" to mean "a pipeline *other than a* gathering or *transmission line*." (emphasis added). The PHMSA Final Rule injected ambiguity by adding the phrase "or connected series of pipelines" to the definition:

> *"Transmission line means a pipeline* ***or connected series of pipelines****, other than a gathering line, that:*
>
> *(1) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center;*
> *(2) operates at a hoop stress of 20 percent or more of SMYS; or*
> *(3) transports gas within a storage field.*
> *Note:*
> *A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas."*[36]

For the reasons given in AGA's Petition for Reconsideration of the PHMSA Final Rule, PHMSA's addition of the phrase "or connected series of pipelines" in the definition of "transmission line" makes it impossible to determine where the demarcation point exists between transmission and distribution line assets. If PHMSA does not remove this phrase, EPA will need to clarify its own definition of "distribution pipeline" in 40 C.F.R. 192.3 to prevent its definition from becoming void for vagueness as well as arbitrary and capricious. The simpler solution will be for PHMSA to remove the phrase from its definition. The Associations urge EPA to encourage PHMSA to do so.

[36] *Id.* (emphasis added).

VII. The Associations Support INGAA's Comments regarding EPA's GHG Reporting Rule Proposals for Natural Gas Transmission, Storage and LNG Operations.

Many of AGA's members operate intrastate natural gas transmission pipelines, transmission compression, underground storage and/or LNG storage facilities as part of the gas utility system regulated by their state's utility commission. These intrastate facilities are subject to the same Subpart W reporting regulations as the interstate counterparts operated by INGAA's members. While APGA members generally do not operate such facilities in their smaller systems, they are concerned about the potential unnecessary cost burdens on their upstream interstate pipeline suppliers that could be imposed by the proposed changes to Subpart W. Accordingly, the Associations support INGAA's comments on EPA's Subpart W proposed revisions for natural gas transmission, storage, and LNG operations as applied to both interstate and intrastate gas utility facilities.

The Associations offer the foregoing comments to assist EPA in its ongoing effort to improve the GHGRP and particularly Subpart W. If you have any questions, please contact Pam Lacey at placey@aga.org, Tim Parr, AGA Deputy General Counsel at tparr@aga.org, or Erin Kurilla at ekurrilla@apga.org.

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APPENDIX A

AGA & APGA Comments filed October 6, 2022 on EPA Proposed Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule, 87 Fed. Reg. 36920 (June 21, 2022)

Docket No. EPA-HQ-OAR-2019-0424

PETITION FOR RECONSIDERATION

Filed by AGA in Docket No. PHMSA-2011-0023

On Sept. 23, 2022

BEFORE THE
UNITED STATES DEPARTMENT OF TRANSPORTATION
WASHINGTON, D.C.

Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments	)	Docket No. PHMSA-2011-0023

PETITION FOR RECONSIDERATION

FILED BY
AMERICAN GAS ASSOCIATION

September 23, 2022

I. Introduction

Pursuant to 49 C.F.R. § 190.335(a), the American Gas Association (AGA)[1] submits this Petition for Reconsideration (Petition) of the final rule issued by the Pipeline and Hazardous Materials Safety Administration (PHMSA) titled "Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments" Final Rule ("Final Rule").[2]

AGA is deeply committed to continuing to improve natural gas pipeline safety by working collaboratively with PHMSA, and other stakeholders, to develop regulations that provide meaningful advancements in pipeline safety. This constructive relationship has resulted in numerous regulatory developments that have made significant enhancements to pipeline safety and have helped to achieve the largely positive safety performance of the nation's natural gas pipeline system.

AGA strongly supports the Final Rule, which will enhance pipeline safety and advance our industry's efforts to achieve a perfect safety and reliability record for our nation's natural gas pipelines. AGA commends PHMSA for its monumental efforts to finalize the rule. PHMSA and the entire industry worked diligently to produce this Final Rule and many other regulations that will help optimize the safety of the natural gas transmission system in our country.

Through this petition, AGA only seeks reconsideration of three specific issues regarding § 192.3 and a change in the effective date of the rule to ensure the requirements of the Final Rule are clear and that the operators have adequate time to properly implement this significant rule. After reviewing the Final Rule, AGA's members identified these issues that should be clarified and corrected based on the recommendations of the Gas Pipeline Advisory Committee (GPAC) and language included in the preamble. Of the three items that required formal action, two issues will likely require a regulatory amendment while the other can likely be resolved with an official FAQ and a clear response to this petition clarifying PHMSA's intent.

II. AGA requests reconsideration of § 192.3 - Definitions

AGA requests reconsideration of two definitions within § 192.3 – The definition of a transmission line and the definition of in-line inspection.

Definition of a Transmission Line:

AGA requests PHMSA reconsider the inclusion of the phrase "or connected series of pipelines" in the amended definition of Transmission line (ref. RIN 2137-AF39 192.3 *Definitions*). AGA is concerned that operators could be led to various interpretations of the phrase "or connected series of pipelines", with potentially vastly disparate results. Accordingly, the phrase is Consitutionally vague. Its inclusion would

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[1] The American Gas Association, founded in 1918, represents more than 200 local energy companies that deliver clean natural gas throughout the United States. There are more than 76 million residential, commercial, and industrial natural gas customers in the U.S., of which 95 percent — more than 72 million customers — receive their gas from AGA members. Today, natural gas meets more than thirty percent of the United States' energy needs.

[2] Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments, 87 Fed. Reg. 52224 (Aug 24. 2022) [hereinafter *Final Rule*].

not allow a reasonable operator to be able to determine the extent of applicable regulatory obligations under PHMSA's rule – and under EPA's greenhouse gas reporting rules for the natural gas industry (40 C.F.R. Part 98, Subpart W) which imposes reporting obligations for "distribution pipelines," as defined by PHMSA to mean those pipelines that are not defined as "transmission."[3] Of note, this phrase was not included in PHMSA's Notice of Proposed Rulemaking and the transcript of the March 27, 2018, GPAC meeting indicates that there was very limited discussion of the phrase when proposed revisions were discussed. The Industry Comments submitted in response to the March 27, 2018, GPAC meeting on May 1, 2018 ("May 2018 Comments") noted that some of the discussion during the GPAC meeting on this topic was incorrect and also recommended that the phrase be struck from the definition of transmission pipeline (for ease of reference, the relevant excerpt of the May 2018 Comments is included below). The Final Rule gives no indication that these concerns or the recommendation from the Associations were considered. Therefore, AGA respectfully requests PHMSA review the Associations' concerns associated with including the phrase "or connected series of pipelines" in the definition of "Transmission line" and remove the phrase from the definition of "Transmission" pipeline, for the reasons given in our comments.

As noted above, on May 1, 2018, the Associations submitted "Comments on Pipeline Safety: Safety of Gas Transmission Pipelines, MAOP Reconfirmation, Expansion of Assessment Requirements and Other Related Amendments" to PHMSA. Page 6 of these Comments clearly identifies the Associations concern of likely confusion resulting from inclusion of the phrase "or connected series of pipelines":

> [Regarding] "*or connected series of pipelines*":
>
> (2) *The addition adds confusion as to where a transmission line begins and ends. PHMSA did not provide GPAC members with background information on the intent of this change. This change could not only impact the demarcation between transmission and distribution lines, but also affect gathering lines, which have not yet been discussed by the GPAC.*

The intent of the clause "*or connected series of pipelines*" was discussed at the March 27, 2018, GPAC Meeting. See Transcript, page 264, clearly indicating that meeting participants agreed that:

> *"…a transmission line can, indeed, connect to another transmission line."*

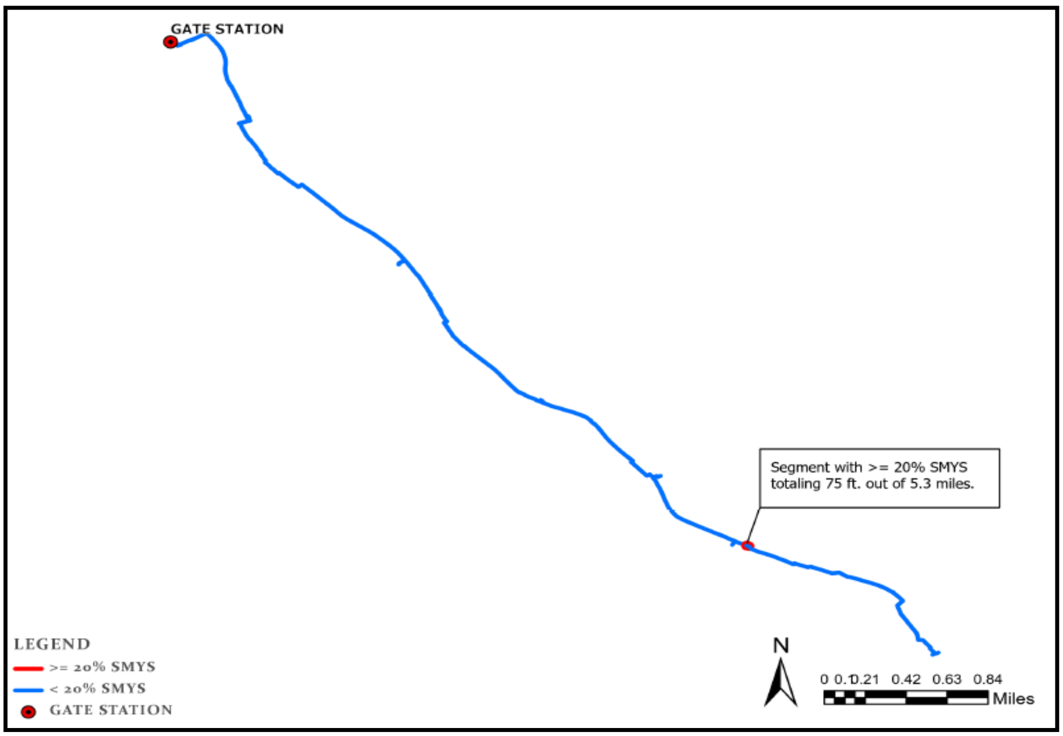
Discussions at the AGA-hosted RIN 2 Webinar on August 31, 2022, revealed complications with the meaning of the clause "or connected series of pipelines". During this meeting, PHMSA comments suggested that if a pipeline contains a connected mix of pipe segments with MAOPs producing hoop stresses both less than and greater than 20% SMYS, then the entire pipeline is a transmission line.

An open question remains: If a "mixed SMYS" pipeline system is a transmission line by virtue of being connected, what represents a "disconnection"? A city gate station is ultimately connected to a meter operating at inches water column, as natural gas constituents (e.g., methane molecules) can travel unhindered from the station to the meter. A reasonable interpretation is that a meter at low pressure is not part of the transmission system. PHMSA's interpretation also raises other questions:

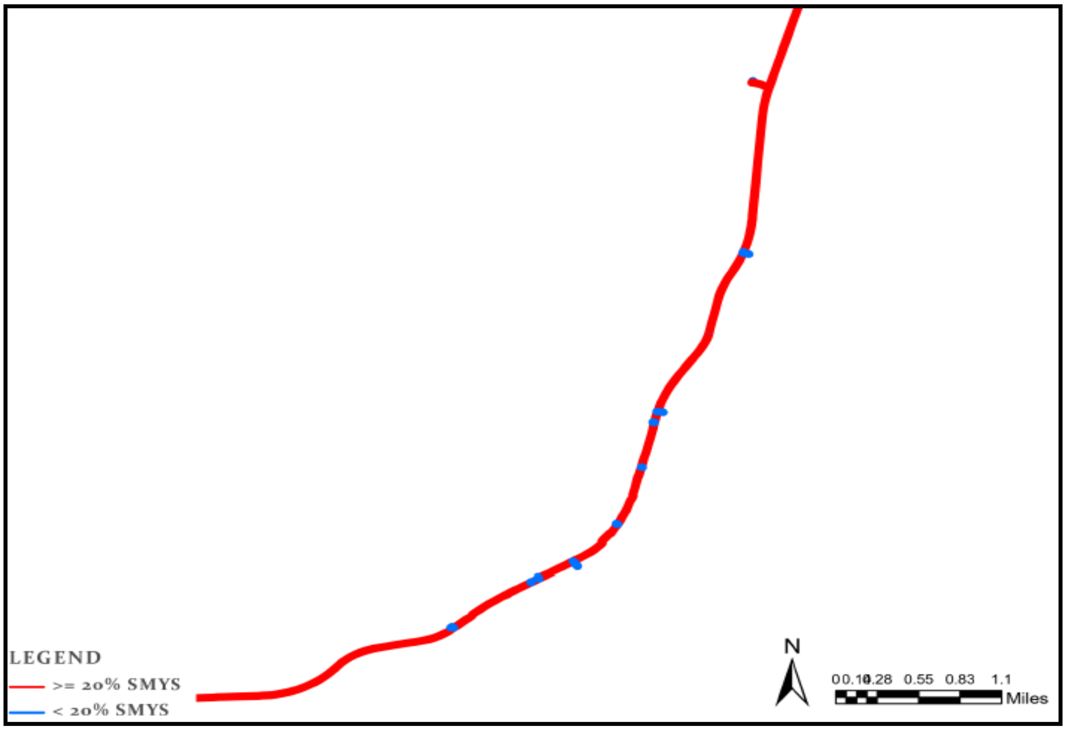
[3] 40 C.F.R. 98.237

- Is a flow control device, such as a regulator, control valve, block valve, or some combination thereof, sufficient to warrant a transmission vs. non-transmission distinction if the upstream MAOP produces hoop stress(es) of 20% SMYS or greater but downstream MAOPs produce hoop stress(es) less than 20% SMYS?
- Consider a connected series of three pipe segments:
  - 4.3 miles of 8” pipe with MAOP at 14% SMYS, connected to
  - 75-ft. of 12” pipe (drilled in) with MAOP at 22% SMYS, connected to
  - 1 mile of 8” pipe at 14% SMYS.

  The >20% SMYS 12” pipe constitutes 0.3% of the overall pipeline’s length. Is this proportion sufficient to classify the complete series of pipes as transmission? See the image below for a representation of the actual scenario:

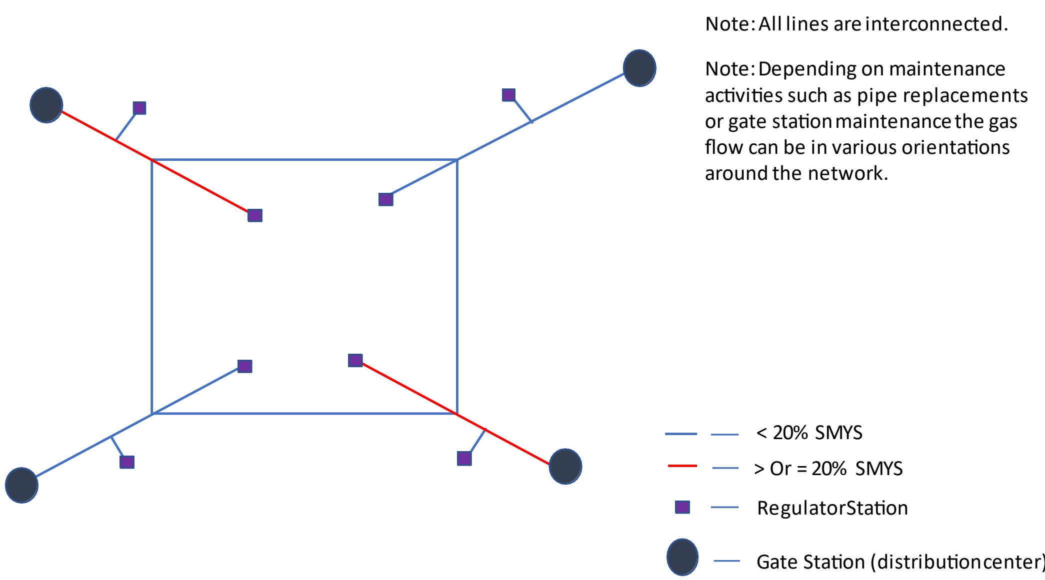


Operators acknowledge that the reverse situation may also be true. That is, a line that is predominantly > 20% SMYS with small segments of < 20% SMYS pipe:



It is important to note that these images reflect many LDC systems. That is:

- Many LDCs operate a network of pipelines with MAOPs resulting in hoop stresses in excess of 20% SMYS on their perimeter (red) and lower MAOPs (blue) as pipe travels toward the core of the system. Note that pipeline systems are "connected", and all piping is downstream of a distribution center (i.e., gate station). Below is another diagram to reflect this scenario:



- Defining the entire length of a pipeline as transmission when only a small segment operates at or above 20% SMYS presents significant issues and costs for operators that were not contemplated or justified in the final rule. Operators will now be required to operate the entire length of these pipelines as transmission, including meeting Subpart O transmission pipeline integrity requirements. Most high-pressure pipelines in distribution systems are not capable of in-line inspection due to piping restrictions, lower operating pressures, and low flows. In addition, they may be the only feed to a system or are a primary feed to a portion of a distribution system and therefore cannot be taken out of service for hydrotesting. Direct assessment may not be possible or appropriate based on the potential threats.

It should be noted that many of AGA's operators responded that PHMSA's proposed change to the definition will add hundreds to thousands of miles of transmission lines. This has not been considered in PHMSA's cost benefit analysis.

AGA is requesting that PHMSA revise the language within §192.3 to the following. Edits are highlighted in **red** below:

§192.3 Definitions

Transmission line means a pipeline ~~or connected series of pipelines~~, other than a gathering line, that:…

Definition of In-Line Inspection:

AGA is also concerned with how the new definition of "in-line inspection (ILI)" might be interpreted for its applicability to § 192.624(a)(2)(iii) and § 192.710(a)(2), specifically with respect to pipeline segments located in Moderate Consequence Areas (MCA) that can accommodate an ILI. AGA requests that PHMSA clarify that the term "***instrumented inline inspection tool"*** refers to free-swimming tools, *i.e.*, tools that do not require a permanent modification to the pipeline facility.

The Notice of Proposed Rulemaking defined the term "in-line inspection" as "the inspection of a pipeline from the interior of the pipe using an in-line inspection tool, which is also called *intelligent* or *smart pigging*.[4] During the March 27, 2018, GPAC meeting, PHMSA and the GPAC agreed to further clarify the proposed definition by adding the following a sentence stating "[t]his definition includes tethered and self-propelled inspection tools."[5] Several GPAC members expressed concern that existing language in § 192.710 and § 192.624 that refers to pipelines located in MCAs that can accommodate ILIs could be potentially mis-interpreted to require an operator make permanent facility modifications to accommodate ILI tools.[6]

To address this concern, PHMSA agreed to include language in the Final Rule's preamble that clarifies that the applicability language in § 192.710 and § 192.624 is limited exclusively to pipeline segments

[4] Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines; Notice of Proposed Rulemaking, 68 Fed. Reg. 20,722, 20,805 (Apr. 8, 2016).
[5] Safety of Gas Transmission and Gathering Pipelines, Gas Pipeline Advisory Committee Meeting, March 26-28, 2018, PHMSA's prepared slides at 126.
[6] Transcript of March 27, 2018 GPAC meeting at 209-215.

that can accommodate free-swimming ILIs, *i.e.*, tools that can be deployed without the pipeline having to be modified to accommodate an ILI.[7]

In the Final Rule, PHMSA adopted a definition of "in-line inspection" that is based on definitions in NACE SP0102-2010, including the sentence stating that the definition "includes tethered and self-propelled inspection tools."[8] While the Final Rule states that "an ILI can include both tethered and self-propelled (*i.e.*, 'free-swimming') tools,[9] the preamble does *not* clarify that the applicable language in § 192.710 and § 192.624 is limited to pipeline segments that can accommodate free-swimming ILIs.

AGA's requested clarification is important to ensure that the term "instrumented inline inspection tool" in § 192.710 and § 192.624 refers to free-swimming tools only. Without this clarification, § 192.710 and § 192.624 may be incorrectly interpreted to require that an operator physically modify a pipeline in order to accommodate ILI tools.

Notably, the preamble of the first transmission Final Rule (RIN 2137-AE72) issued on October 1, 2019, on page 52215, states:

> *PHMSA believes that the term ''piggable segment'' is very widely understood in the industry and is not including additional definitions or regulatory language to expand upon this term. PHMSA understands that a pipeline segment might be incapable of accommodating an in-line inspection tool for a number of reasons, including but not limited to short radius pipe bends or fittings, valves (reduced port) that would not allow a tool to pass, telescoping line diameters, and a lack of isolation valves for launchers and receivers. Some unpiggable pipelines can be made piggable with modest modifications, but others cannot be made piggable short of pipe replacement.*

Finally, PHMSA representatives acknowledged during AGA's RIN 2 webinar the potential confusion that can lead regulators and operators to believe that the new definition of "in-line-inspection" could be applied to the identification of MCAs and those pipelines that require MAOP reconfirmation. During the RIN 2 webinar, PHMSA representatives expressed that a correction or clarification should be issued, since this was certainly not the intention.

To resolve this issue and provide Operators clarity, AGA requests that PHMSA:

i) Respond to this Petition, affirming that the definition of "in-line-inspection" is not applicable to § 192.624(a)(2)(iii) and § 192.710(a)(2)
ii) Issue an FAQ that reflects this same position for enforcement purposes

III. <u>AGA requests reconsideration of the final rule's 9-month effective date</u>

The effective date of most of the provisions in the Final Rule is May 24, 2023, just nine months after the date of publication of the Final Rule in the Federal Register. AGA requests reconsideration of this effective date for implementing 22 code revisions and adding 2 new code sections (192.478 and 192.712) because requiring the implementation of the new regulatory requirements, including newly incorporated industry standards NACE's SP0204 (SCCDA) and SP0206 (ICDA for Normally Dry Natural

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[7] Transcript of March 27, 2018 GPAC meeting at 198, 215 (statement of Mr. Nanney).
[8] 87 Fed. Reg. at 52,267 (to be codified at 49 C.F.R. § 192.3).
[9] 87 Fed. Reg. at 52,256.

Gas), within nine months is simply not enough time to implement a successful rollout of numerous significant regulatory changes. As described in more detail below, the implementation begins with revising and developing new procedures and training modules. In addition, once these documents are approved, time is needed to change processes to inform and train those employees who are required to execute the new/revised activities as a result of the rule. Also, some of the new regulatory requirements may require the development and introduction of new computer technology which inherently takes extensive time to implement.

The scope of the Final Rule is comprehensive and broad, and as explained in the Trade Associations' June 6, 2018, comments, implementing the new requirements will be complex and time-consuming. To realize the full safety benefits of the new requirements, operators need sufficient time to correctly and successfully implement the requirements.

Compliance with the requirements of the Final Rule will not be simple. Processes and procedures affected by new requirements include design, operation, maintenance, emergency preparedness and response, integrity management, and operator qualification. Amending these procedures to reflect new regulations requires that operators examine processes across their systems and understand how they are affected by new requirements. An operator must amend existing procedures to reflect new processes, and in some cases, create new ones. Revisions to one procedure often affects other procedures that may not be directly addressed by the new regulations. Subject matter experts from across various functions and disciplines must be consulted and revised procedures must be vetted by appropriate personnel, including operating staff and management. An operator also may have to update its information technology infrastructure to accommodate new processes, including data and document management. Moreover, staff must be fully trained on the new procedures and, if necessary, qualified on new covered tasks under the operator's operator qualification procedures. In addition, an operator must develop and implement a management of change (MOC) process before implementing new procedures and processes.

AGA believes the Final Rule's nine-month compliance schedule does not allow enough time for operators to successfully implement the new regulatory requirements mandated by the Final Rule. AGA members include a wide range of natural gas utility companies, including some that operate in one state and some that operate in multiple states, which can add additional complexity to the process of implementing a comprehensive new regulatory scheme. Nine months does not reasonably accommodate all the work required to effectively implement the new requirements and does not account for the demands placed on an operator's staff.

Additionally, the challenges of implementing the Final Rule's new requirements are exacerbated by the fact that operators also are simultaneously working to implement the requirements of PHMSA' recently issued Valves Final Rule, which becomes effective October 5, 2022, and requires compliance by April 10, 2023, for the installation of rupture mitigation valves. The Valves Final Rule, which is also an extremely complex rule, requires that operators, among other things, implement enhanced valve maintenance procedures, including annual testing and response time drills, perform risk assessments and install rupture mitigation valves in HCAs if an operator determines it would efficiently protect an HCA. Operators must also implement new emergency response and post-accident procedures. Implementing the Valves Final Rule requires examination of processes, the development of new procedures, and the dedication of the same personnel who are now are called upon to implement the Final Rule.

In consideration of the above, AGA seeks reconsideration of the Final Rule's nine-month implementation deadline and requests that PHMSA amend the Final Rule to provide operators 18 months from the date of publication to implement all provisions of the Final Rule.

<u>Conclusion</u>

For the reasons stated in this petition, AGA requests modifications to the Final rule as shown in **red** below, that PHMSA respond to this Petition, affirming that the definition of "in-line-inspection" is not applicable to § 192.624(a)(2)(iii) and § 192.710(a)(2), issue an FAQ that reflects this same position for enforcement purposes, and provide operators 18 months from the date of publication to implement all provisions of the Final Rule

§192.3 Definitions:

> *Transmission line* means a pipeline ~~or connected series of pipelines~~, other than a gathering line, that:…

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APPENDIX B

AGA & APGA Comments filed October 6, 2022 on EPA Proposed Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule, 87 Fed. Reg. 36920 (June 21, 2022)

Docket No. EPA-HQ-OAR-2019-0424

MacMullin, Rongere, "Measurement-based emissions assessment and reduction through accelerated detection and repair of large leaks in a gas distribution network"

(June 10, 2022)

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Measurement-based emissions assessment and reduction through accelerated detection and repair of large leaks in a gas distribution network

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June 10, 2022

Abstract

This article describes a method to use a mobile leak detection system to quantify methane emissions from a gas distribution system and reduce them by accelerating the detection and repair of large leaks. A common practice within the current regulatory framework uses an approach where operators report their network emissions by applying an average emission factor for all leaks, sometimes sorted by pipe material and type of assets. Such an approach does not enable the prioritization of large leaks that is key for an effective emissions abatement program. In addition, it does not address specificity of gas systems and operator leak detection practices. The approach described here allows for data-driven system-wide emissions quantification that is specific to the network and not subject to operator bias. Furthermore, we show that for a sensor with a sufficiently low detection limit, the calculated emissions are independent of the

precision of the measurement if the uncertainties are correctly considered. Finally, we describe a program where only the largest leaks are rapidly identified for repair, and demonstrate how a significant methane emissions abatement may be achieved without increasing the number of repaired leaks compared to routine survey.

Introduction

Numerous studies have been performed to update methane emission estimates initially established by the Gas Research Institute (GRI) for the US Environmental Protection Agency (EPA) in 1992-1996[1] and provide a baseline for abatement efforts. They all demonstrated the same pattern; most of the leaks are small and generally only contribute marginally to the overall emissions while a small number of several order of magnitude larger leaks are dominant.

For example, Figure 1 shows the results of measurements performed by GRI in 1996 and by Washington State University (WSU) in 2015 on the pipelines of gas distribution systems.[2] First, the difference between the two curves is a testament to the progress made by gas operators across the country in reducing the leakage of their distribution networks that are today about 5 times tighter than 20 years ago. The figure also shows that leak sizes vary from less than 10^{-2} ft^3/hr up to more than 10^2 ft^3/hr (a range of more than four orders of magnitude), with a small number of large leaks that dominate the total emissions. In fact, this phenomenon is even more patent now than it was; GRI reported that 20% of leaks, greater than 10 ft^3/hr, accounted for about 80% of methane emissions while WSU observed that only 2.2% of leaks were greater than 10 ft^3/hr but they still represented 56% of total emissions.

These results were recently summarized by Brandt et al. (see Figure 2), who demonstrated that across assets of the gas value chain as well as across component types, most emissions were owing to a small fraction of leaks, typically 5% or less, that are generally called *Super Emitters*. This skewed leak size distribution represents both a challenge and an opportunity.

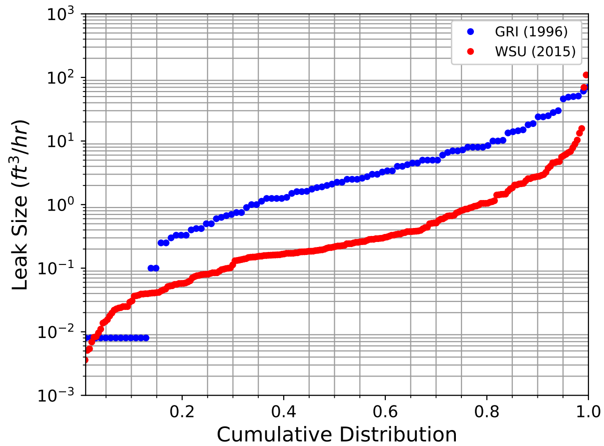

Figure 1: Cumulative distribution of leak sizes for leaks in a gas distribution network reported by Harrison et al., GRI (1996) and Lamb et al., WSU (2015).

A challenge because any attempt to characterize the methane emissions of a system must collect large samples to correctly capture the portion of large leaks. An opportunity because substantial reduction can be accomplished with an optimal repair or replacement effort if these large leaks are detected and identified rapidly.

Gas Leak Detection and Emissions Quantification

This study used a Picarro vehicle-based mobile platform that identifies the characteristic signatures of natural gas leaks by analyzing the methane plumes as they propagate in the atmosphere and intersect the path of the vehicle. The sensor is a parts-per-billion sensitivity gas analyzer based on Cavity Ring Down Spectroscopy (CRDS) measuring atmospheric gas composition and other tracers including ethane.[4] The system also measures GPS position, atmospheric conditions, and uses algorithms to combine these measurements from multiple measurement sessions within a natural gas infrastructure, taking advantage of varying atmospheric conditions (wind direction, wind speed, and atmospheric stability), and aggregates these measurements to build up statistics on the location and flow rates of measured methane sources.

As the vehicle transects the gas plume the emission (flow) rate of a source is calculated

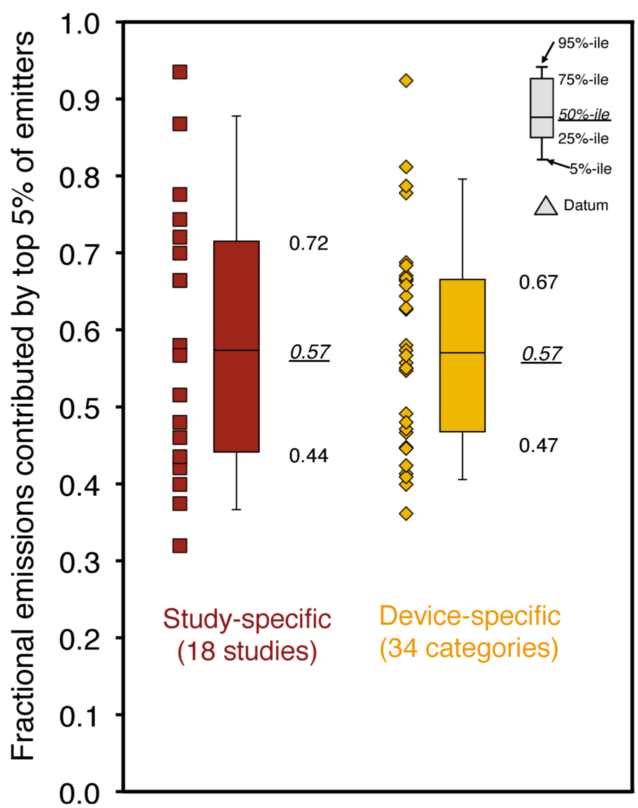

Figure 2: Share of methane emissions contributed by top 5% of emitters. Figure reproduced from Brandt et al.

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by directly measuring the concentration profile and instantaneous wind. Accurate measurements are achieved through the fast response time (4 Hz) of the methane gas analyzer, which provides good spatial resolution of the concentration signal. In standard engineering terminology this method is analogous to a control volume approach for quantifying gas flow rates.[5] The vehicle drives downwind of the leak and captures methane emissions over a control surface along the vehicle's path. The inflow condition for the control volume is determined from sensitive measurements of the background methane concentration. The methane flow rate Q is derived from the volumetric flux equation:

$$Q = \iint [C(y,z) - C_0] \cdot u(y) dy dz, \tag{1}$$

where C is the concentration at each measurement point of the cross-sectional area of the plume and C_0 is the background methane concentration. The vehicle samples the concentration along a line through the plume in the y direction and the height of the plume z is inferred from the measured width in the y direction, where the plume is assumed to be homogenous in concentration across this surface. The quantity u is the component of wind speed measured by the anemometer normal to the path of the vehicle.

The method relies on the vehicle to make multiple passages through the network to increase the probability to detect leaks. Multiple detections of a plume originating from a source are aggregated using a geospatial clustering algorithm such as DBSCAN,[6,7] HDBSCAN,[8] or OPTICS.[9,10] The parameters of the clustering algorithm indicate the spatial scale, and are adjusted to achieve as close as possible to a 1-to-1 relationship between a measurement and a gas leak. An example of the geospatial clustering is shown in Figure 3. Detecting a plume multiple times from a single source also serves to improve the precision of the emissions estimate. Using the associations determined by the clustering algorithm, multiple independent measurements of plumes from a given source are averaged to report an estimate for the leak size.

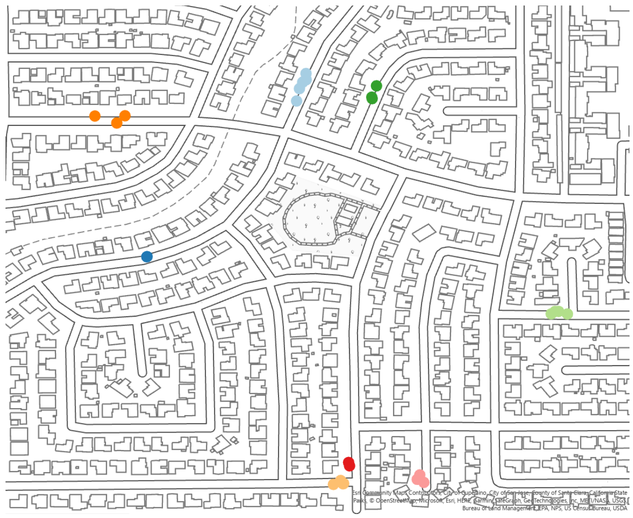


Figure 3: Example of geospatial clustering to associate one or more detections with a source. Each point represents the location where a single plume was detected. Measurements that are clustered together are shown by like colors.

Validation of the Measurement

A study performed by NYSEARCH between 2015 and 2017 on three mobile leak detection systems provided a solid validation data set.[11] The test covered three orders of magnitude in leak size consistent with observations in the field. A similar validation study using the Picarro system has been performed annually since 2018 at the Pacific Gas and Electric Company (PG&E) Gas Safety Academy in Winters, CA. Controlled leaks were setup in various above and below-ground configurations representing leaks typically found in a distribution network. An inline mass flow controller provided a precise measurement of the actual flow rate of the leak. Data were collected by the Picarro system according to the standard driving protocol which includes six passes by each leak with three in each direction. In addition to the controlled testing, 53 leaks that were identified by the Picarro system on PG&E's network were validated using a High Flow sampler. The field validation exercise focused on leaks that were measured by the Picarro system as more than 5 ft^3/hr. The purpose of these field tests was to verify that the accuracy observed in a broad range of conditions was consistent with the measurement performed during the validation tests in application of the method developed by NYSEARCH in 2018 with the support of PHMSA.[12] Figure 4 summarizes the leak flow rate as estimated by the mobile systems compared to the actual values as measured with a High Flow sampler or as set in the case of controlled leaks. It was observed that the mobile quantification systems were able to estimate the order of magnitude of the leak flow rates: 78% of the data points were within a one order of magnitude band – a factor of $\sqrt{10}$ times greater and $\sqrt{10}$ times less than actual values.

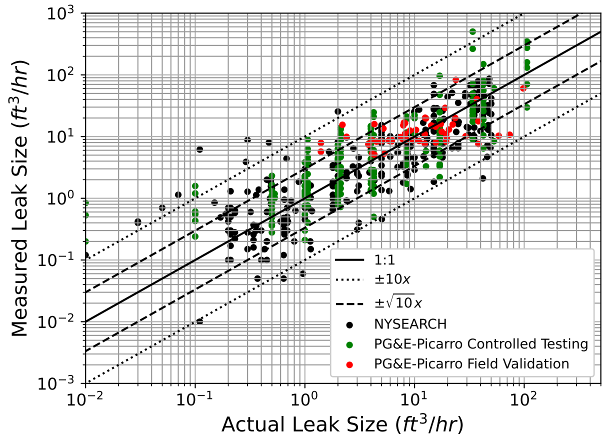


Figure 4: Validation testing unity plot. Quantification system measurements versus actual leak sizes.

Emissions Measurements in a Distribution Network

Since 2014, PG&E has used the Picarro vehicle-based methane detection system for its leak survey program.[13] Any portion of PG&E's distribution system is inspected at the minimum every three years, some areas being surveyed as often as every year. In 2018, to further reduce methane emissions, PG&E introduced a *Super-Emitter Program*, which implemented an additional survey focused only on large leaks. Performed every year on the entire distribution system, it aims to detect only leaks greater than 10 ft^3/hr and prioritize their repair to take advantage of their disproportionally large contribution to methane emissions. Based on the leak size distribution observed by WSU, rapidly detecting and repairing these leaks could lead to up to 56% emission abatement. However, special attention must be paid to the representation of uncertainties in order to correctly assess the impact of the program because, even if the quantification system is evenly calibrated, i.e. it has a symmetrical probability to overestimate or underestimate the flow rate of a given leak, the skewed leak size of the gas distribution system makes that, for a measured value of a larger flow rate especially greater than 10 ft^3/hr, the actual leak size has a much higher probability to be overestimated than underestimated.

Figure 5 illustrates this phenomenon for a leak measured by the mobile system as 1 ft^3/hr. The measurement uncertainty spans one order of magnitude (A), consistent with the validation testing. Because of the of the heavy-tailed leak size distribution, the positive interval, Δ_+, is much smaller than the negative interval Δ_-. This corresponds to approximately 70% chance to overestimate the leak compared to 30% to underestimate the leak. Therefore, the most probable value corresponding to the measurement will be less than the measured value.

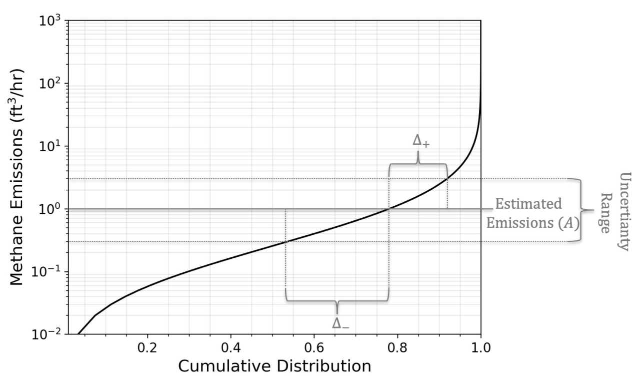


Figure 5: A single leak measured at A=1 ft^3/hr with a $\pm\sqrt{10}$x uncertainty from a skewed distribution will have a larger probability to be overestimated (Δ_-) than underestimated (Δ_+).

The mobile system covers a large range of leak sizes from less than 0.1 to more than 100 ft^3/hr. The low Minimum Detection Limit (MDL) associated with a consistent quantification precision across the full range of leak sizes in a distribution network is key to correctly capture the uneven proportion of small and large emitters. The MDL is not a fixed threshold, but varies as a function of measurement conditions such as terrain, wind speed, and atmospheric stability. It must therefore be much lower than the leak sizes that substantially contribute to the total emissions to avoid cases of missed detections and mischaracterization around the MDL that will affect the overall emissions assessment.

Measurement Based Emission Factors

To evaluate the impact to the system-wide emissions where only the largest leaks are prioritized for repair, leaks and detections are classified in four decade bins from 10^{-2} to 10^{2} ft^3/hr. These bins can be adjusted in function of the threshold used to define a large leak. The probability for actual leaks to belong in each bin can be calculated using Bayesian inference:

$$P\langle A_i|B_j\rangle = \frac{P\langle B_j|A_i\rangle \cdot P\langle A_i\rangle}{P\langle B_j\rangle}, \tag{2}$$

where A_i is the statement: *the actual size of the leak is in the bin defined by* $[10^i, 10^{i+1}[$ and B_i is the statement: *the leak size as estimated by the mobile system is in the bin defined by* $[10^j, 10^{j+1}[$. The indices i and j vary from -2 to 1; if i or $j = 1$ the interval is $[10, \infty[$, if i or $j = -2$ the interval is $[0, 0.1[$.

$P\langle A_i|B_j\rangle$ represents the probability for the statement A_i to be true if the statement B_i is true.

$P\langle B_j|A_i\rangle$ represents the probability for the statement B_j to be true if the statement A_i is true.

$P\langle A_i\rangle$ represents the probability of A_i to be true.

$P\langle B_j\rangle$ represents the probability of B_j to be true.

$P\langle B_j\rangle$ is calculated using the formula:

$$P\langle B_j\rangle = \sum_i P\langle B_j|A_i\rangle \cdot P\langle A_i\rangle. \tag{3}$$

For this analysis, the experimental data of WSU for distribution mains and services have been fit to a lognormal distribution, shown in Figure 6. The average flow rate assigned to each bin noted here as $EF(A_i)$ is obtained from the fit to the WSU distribution and is summarized in Table 1.

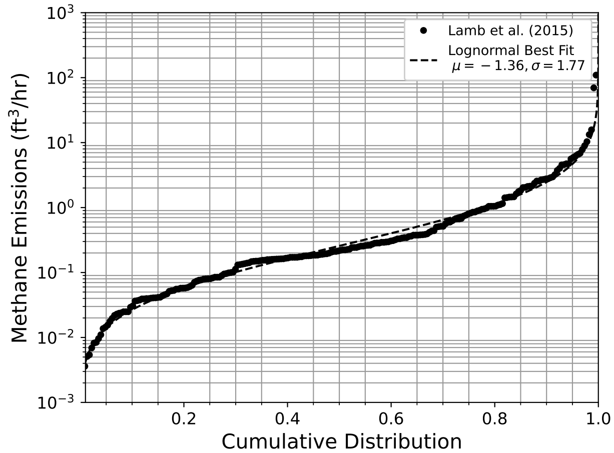


Figure 6: Experimental data from WSU fit to a lognormal distribution

Table 1: Fraction of leaks and average emissions in four order-of-magnitude bins based on a distribution of leak sizes fit to the WSU dataset.

Leak Bin	Leak Size (ft^3/hr)	% Leaks $P\langle A_i \rangle$	Average Flow Rate in Bin (ft^3/hr) $EF(A_i)$
A_1	$[10, \infty[$	2%	25.2
A_0	$[1, 10[$	20%	2.8
A_{-1}	$[0.1, 1[$	48%	0.4
A_{-2}	$[0, 0.1[$	30%	0.04

The validation data described above were used to represent the precision of the mobile quantification system. The distribution of errors observed during the tests was modeled as a lognormal function with a width, $\sigma = 0.95$. The matrix $[v_{ij}]$ defined as $v_{ij} = P\langle B_j | A_j \rangle$ is represented in Table 2. From here, we calculate the inverse matrix $[v_{ij}^{-1}]$ shown in Table 3.

In addition, the flow rate to be assigned to a leak measured as in a bin B_j is obtained by the formula:

$$EF(B_j) = \sum_i P\langle A_i | B_j \rangle \cdot EF(A_i). \tag{4}$$

Table 2: Probability a leak of size A_i is measured as size B_j

Actual Leak Size (ft^3/hr)			Measured Leak Size (ft^3/hr): B_{-2} $[0, 0.1[$	B_{-1} $[0.1, 1[$	B_0 $[1, 10[$	B_1 $[10, \infty[$
	A_1	$[10, \infty[$	0%	0%	16%	84%
	A_0	$[1, 10[$	0%	17%	66%	17%
	A_{-1}	$[0.1, 1[$	17%	66%	17%	0%
	A_{-2}	$[0, 0.1[$	84%	16%	0%	0%

Table 3: The probability a leak measured as size B_i is actually size A_j for a leak size distribution that follows WSU.

Measured Leak Size (ft^3/hr)			Actual Leak Size (ft^3/hr): A_{-2} $[0, 0.1[$	A_{-1} $[0.1, 1[$	A_0 $[1, 10[$	A_1 $[10, \infty[$
	B_1	$[10, \infty[$	0%	0%	68.0%	32.0%
	B_0	$[1, 10[$	0%	37.5%	61.1%	1.4%
	B_{-1}	$[0.1, 1[$	11.9%	79.5%	8.6%	0%
	B_{-2}	$[0, 0.1[$	75.3%	24.7%	0%	0%

Table 4 shows the percent of measurements and corresponding average actual flow rate in each order-of-magnitude bin based on the direct measurement. The impact of the precision of the measurement system can be seen here; the number of leaks detected as large leaks (> 10 ft^3/hr) is 5% compared to 2% of actual large leaks. Correspondingly, the average flow rate of leaks detected as large leaks is 10.0 ft^3/hr compared to 25.2 ft^3/hr if each leak could be perfectly classified in its respective bin.

Table 4: Fraction of measurements and average emissions in four order-of-magnitude bins based on a distribution of leak sizes fit to WSU.

Measured Leak Bin	Leak Size ($\mathrm{ft}^3/\mathrm{hr}$)	% Measurements $P\langle B_j \rangle$	Average Flow Rate in Bin ($\mathrm{ft}^3/\mathrm{hr}$) $EF(B_j)$
B_1	$[10, \infty[$	5%	10.0
B_0	$[1, 10[$	22%	2.2
B_{-1}	$[0.1, 1[$	40%	0.5
B_{-2}	$[0, 0.1[$	33%	0.09

Estimating Total Emissions

The emissions associated with each bin is given by:

$$\text{Emissions}(B_j) = N \cdot P\langle B_j \rangle \cdot EF(B_j), \tag{5}$$

where N is the total number of leaks found and $N \cdot P\langle B_j \rangle$ is the number of leaks measured in the bin B_j.

The total emission of the network may then be calculated as:

$$\text{Emissions} = \sum_j \text{Emissions}(B_j) = N \cdot \sum_j P\langle B_j \rangle \cdot EF(B_j). \tag{6}$$

When replacing $EF(B_j)$ from Equation 4 into Equation 6, we obtain:

$$\text{Emissions} = N \cdot \sum_j P\langle B_j \rangle \cdot [\sum_i P\langle A_i | B_j \rangle \cdot EF(A_i)], \tag{7}$$

then replacing $P\langle A_i | B_j \rangle$ from Equation 2 into Equation 7, we obtain:

$$\text{Emissions} = N \cdot \sum_j \sum_i P\langle B_j | A_i \rangle \cdot P\langle A_i \rangle \cdot EF(A_i), \tag{8}$$

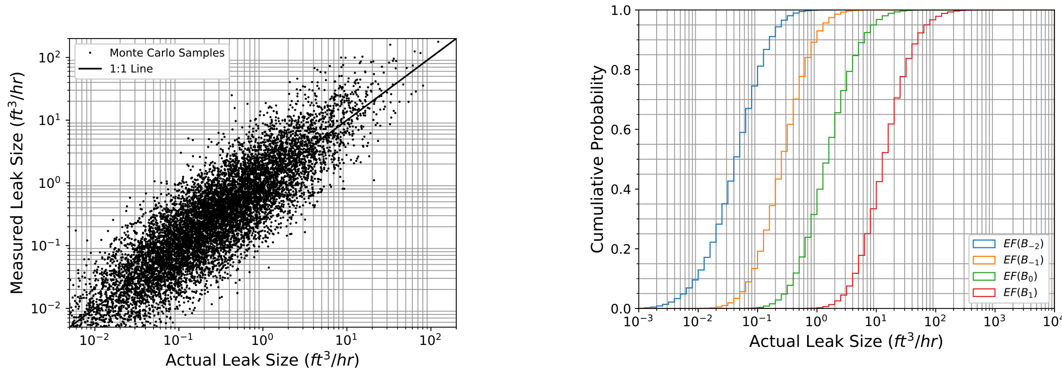
with $\forall i, \sum_j P\langle B_j|A_i\rangle = 1$. Then:

$$\text{Emissions} = N \cdot \sum_i P\langle A_i\rangle \cdot EF(A_i) = N \cdot \sum_j P\langle B_j\rangle \cdot EF(B_j). \tag{9}$$

We observe from Equation 9 that the total emissions estimated through direct measurement are equal to the actual emissions independently of the precision of the measurement if the MDL is low enough to cover the full range of emissions and if the prior (estimated distribution of leak size) and uncertainties are correctly considered. On the other hand, ignoring the impact of uncertainty on predicted emissions would lead to a very different result. For the example presented here, the estimated emissions would be 60% greater than the actual emissions. Finally, the four-bin approach implemented for the purpose of capturing methane abatement related to the early detection and repair of large leaks can be expanded to any number of bins towards a continuous approach as presented below using Monte Carlo simulations.

Monte Carlo Simulations

The simulation process starts by sampling events from the prior distribution, modeled from a lognormal fit to the WSU data with parameters $\mu = -1.36$ and $\sigma = 1.77$. Each sample was then converted to a measurement by multiplying by a sample drawn from the system precision, also modeled as lognormal distribution with parameters $\mu = 0$ and $\sigma = 0.95$. The simulation result confirms the result of the Bayesian method described in the previous sections when the results are binned according to the measured leak size, $[10^j, 10^{j+1}[$. Figure 7 shows the result of 10^5 simulated leaks and the resulting distribution of actual leak rates within each of four order-of-magnitude measurement bins. The 1-to-1 line provides a visual cue to help interpret the results. The higher point density on the left side of the 1-to-1 line, especially for actual leak sizes above 1 ft^3/hr, illustrates the higher probability for the system to overestimate the leak than underestimate it.



(a)

(b)

Figure 7: (a) The result of a Monte Carlo simulation of 10^5 leaks in a gas distribution network. (b) The simulation result represented as a cumulative distribution of the actual leak sizes split into four order-of-magnitude bins based on the measured value.

This approach may be extended to include any number of bins provided a statistically significant number samples are generated in each bin. The result may then be represented as a continuous function which may be used to evaluate the most likely flow rate and uncertainty range based on any measurement provided by the mobile system. Figure 8 shows a continuous function, which is a power law-fit to the simulation result separated into 50 log-uniform bins from 10^{-2} to 10^3 ft^3/hr.

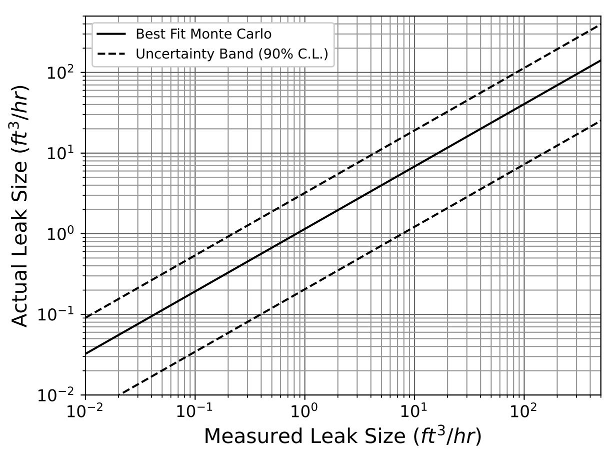


Figure 8: A relationship between actual leak size and measured leak size for leaks in a gas distribution network. This relationship is called $AdjFlow$.

Estimating Emissions from Unknown Leaks

In general, the mobile system will report more indications than there are leaks in the network. Although these indications usually represent real sources of methane, they may not be sources of interest for reporting of emissions - e.g. 3^{rd}-party sources, natural/biogenic sources, or natural-gas vehicles. Furthermore, at PG&E, only below-ground (BG) leaks are of interest to the program as meter-set assembly (MSA) emissions are currently reported separately and characterized through static emission factors.

A model for the probability that an indication was generated from a below-ground leak was developed and validated using a set of leaks that were confirmed through field investigation during the routine leak survey process. The model implemented a decision tree algorithm to determine a below-ground probability index based on properties of the detections such as methane and ethane concentration enhancement, calculated emissions, spatial profile of the concentration signal, and number of detections. Using this relationship, the total number of below-ground leaks in the network may be estimated and the reported emissions may be adjusted accordingly. Each detection is assigned a probability to be related to a below-ground leak $P\langle BG\rangle$ and its contribution is calculated as a function of its measured flow rate as:

$$\text{Flow}(BG) = P\langle BG\rangle \cdot AdjFlow[\text{Measured Flow}], \tag{10}$$

and the flow rate of all open below-ground leaks as detected with the vehicle is:

$$\text{TotalFlow}(BG) = \sum_{BG} \text{Flow}(BG) \tag{11}$$

Large gas distribution networks require a significant amount of time to be fully driven by the mobile system. At PG&E the 42,000 miles of mains and 3.6 million services are covered every year from January to December. These data do not provide a picture of the emissions at a point of time but rather a progressive scanning over the year. Detected leaks may have been open since the beginning of the year or for a shorter period. On the other hand, leaks may occur after the survey and produce methane that must be accounted for. If the leaks appear linearly with time and the survey is performed equally along the year, it can be shown that the methane emissions from leaks that opened after the measurement equals the overestimate of emission assigned to detected leaks when considering that they are open since the beginning of the year. Therefore, the annual emission of the system can be calculated from the number of leaks detected through the surveys as:

$$Emissions = \sum_{BG} \mathrm{Flow}(BG) \cdot [min(\text{end of year, time of repair}) - \text{beginning of year}]. \quad (12)$$

Using such a method it is possible to directly calculate emission of a gas network using the flow rate estimates obtained from the survey vehicles. Such a method avoids the assumption of emission factors. It also fully recognizes the prioritization efforts of gas operators accelerating the repair of larger leaks by associating the actual emissions avoided for each leak repair.

Case Study: PG&E Super-Emitter Program

PG&E in its Super Emitter Program uses the leak size estimates of the mobile methane detection system to identify large leaks in areas not scheduled for leak survey. Each leak that was measured by the mobile system as greater than 10 $\mathrm{ft}^3/\mathrm{hr}$ is assigned with the emission factor $EF(B_1)$=10.0 $\mathrm{ft}^3/\mathrm{hr}$ and leaks measured by the system as less than 10 $\mathrm{ft}^3/\mathrm{hr}$ are assigned with the emission factor $EF(\bar{B}_1)$=0.73 $\mathrm{ft}^3/\mathrm{hr}$. The large leaks are repaired in priority independently of their grade. Smaller leaks are repaired in application of the safety standard of the company.

This effectiveness of the program depends on utility practices; most importantly the time between when the leak is identified and repaired. Table 5 demonstrates an example implementation of the program and the result of a theoretical case of a network that follows a WSU leak size distribution where 1,000 leaks are found during a 5-year survey (20% of the territory is surveyed every year). It assumes that all leaks are repaired immediately after they are identified. Leaks that are found through survey are assigned with an average lifetime of six months and leaks on non-surveyed areas are assigned with a lifetime of the full year.

In this example the first year is considered as a baseline. The total number of leaks in the non-surveyed areas are estimated by assuming a linear leak appearance over five years. The total emissions are estimated using 1.23 ft^3/hr from the average of the WSU leak size distribution. In the first year of a Super-Emitter Program, the non-leak survey areas are driven with the mobile system and the large leaks prioritized for immediate repair. This process results in a 19% emissions reduction compared to the baseline with only 10% increase in the number of repaired leaks. For the second year and later, the number of large leaks found is reduced because the annual detection leaves less time for these leaks to develop. The total emissions reduced is then 29% compared to the baseline with no additional repairs since the program accelerated the detection and repair of large leaks. The large leaks would eventually been detected through routine survey but would have stayed open for a longer time. Additional emissions reduction in the third year and beyond may be realized by a combination of lowering the threshold defining large leak or increasing the measurement frequency in order to reduce the time these large leaks stay undetected.

Discussion

The method presented in this article allows for the most probable estimate of all of the leaks for a given prior leak size distribution, independent of the precision of the measurement method. In practice however, a specific network may have an actual distribution of leak size that is similar or different compared to literature. If network-specific measurements are

Table 5: Example emissions reduction scenario by implementing an annual Super-Emitter program in areas not scheduled for leak survey.

		Leak Survey Areas (20% of Network)	Non-Leak Survey Areas (80%) of Network	Total
Baseline	Number of Leaks	1,000	2,000	3,000
	Emissions (MMcf/y)	5.4	21.5	26.9
	Repaired Leaks	1,000	0	1,000
Year 1	Number of Leaks	1,000	2,000	3,000
	Number of Leaks Detected ≥ 10 ft^3/hr	50	100	150
	Number of Leaks Detected < 10 ft^3/hr	950	1,900	2,850
	Emissions (MMcf/y)	5.4	16.5	21.9 (-19% compared to baseline)
	Repaired Leaks	1,000	100	1,100 (+10% compared to baseline)
Year 2	Number of Leaks	960	1,940	2,900
	Number of Leaks Detected ≥ 10 ft^3/hr	10	40	50
	Number of Leaks Detected < 10 ft^3/hr	950	1,900	2,850
	Emissions (MMcf/y)	5.2	13.9	19.1 (-29% compared to baseline)
	Repaired Leaks	960	40	1,000 (same as baseline)

available (ex. a utility that uses mobile data for routine leak survey), the actual distribution may be estimated from the measurements themselves. The actual leak size distribution $P\langle A_i \rangle$ can be adjusted in such a way that $P\langle B_j \rangle$ coincides with the measured leak size distribution. In addition to having a model of the actual distribution that is specific to the network, this approach also offers the convenience to modify the distribution over time to reflect changes in the network owing to emissions abatement efforts. However, it must be noted that the correction of the measured distribution, $P\langle B_j \rangle$, for both measurement uncertainties and for attribution of indications to below-ground leaks is challenging because of the field validation dataset that it required and the small signal to noise ratio (i.e. below-ground leaks to MSA leaks and other false positives), especially for indications with small concentration enhancement (< 100 ppb). For this reason, using an established prior from literature such as WSU is a reasonable starting point.

With their FEAST model Kemp, Ravikumar, and Brandt[14] have argued that it can be more cost effective to accelerate surveys with low-sensitivity tools detecting only large leaks than it is to perform extensive surveys aiming at detecting all leaks such as inspections performed for safety. A key limitation of their approach, however, was the assumption that a low-sensitivity tool would only detect large leaks while, in reality, large uncertainties affect detection and quantification. Low-sensitivity tools may characterize a smaller leak as large or miss a large leak. Uncertainties would therefore substantially impact the effectiveness of their use for an accelerated repair program. The method presented here using an ultra-low MDL system, including a rigorous accounting for uncertainties, circumvents this limitation and supports the use of fast and sensitive detection systems for the estimate of total methane emissions and prioritization of repairs.

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AGA and APGA's Comments on
"Waste Emissions Charge for Petroleum and Natural Gas Systems"
Docket ID No. EPA-HQ-OAR-2023-0434

Attachment 4: AGA and APGA Comments on May 2023 GHGRP Supplemental Proposal

Submitted via regulations.gov

July 21, 2023

U.S. Environmental Protection Agency
EPA Docket Center
Mailcode 28221T
1200 Pennsylvania Ave., N.W.
Washington, D.C. 20460

Re: AGA and APGA Comments on "Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule," Docket Id. No. EPA–HQ–OAR–2019–0424-0255

The American Gas Association ("AGA") and the American Public Gas Association ("APGA") (jointly "the Associations") appreciate the opportunity to comment on the U.S. Environmental Protection Agency's ("EPA") supplemental notice of proposed rulemaking entitled, "Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule" (hereinafter, Supplemental Notice), which was published in the Federal Register on May 22, 2023.[1]

AGA, founded in 1918, represents more than 200 local energy companies that deliver clean natural gas throughout the United States. There are more than 77 million residential, commercial, and industrial natural gas customers in the U.S., of which 95 percent — more than 73 million customers — receive their gas from AGA members. AGA is an advocate for natural gas utility companies and their customers and provides a broad range of programs and services for member natural gas pipelines, marketers, gatherers, international natural gas companies, and industry associates. Today, natural gas meets more than one third of the United States' energy needs.[2]

APGA is the national, non-profit association of publicly owned natural gas distribution systems. APGA was formed in 1961 as a non-profit, non-partisan organization, and currently has over 740 members in 37 states. Overall, there are nearly 1,000 municipally owned systems in the U.S. serving more than five million customers. Publicly owned gas systems are not-for-profit retail distribution entities that are owned by, and accountable to, the citizens they serve. They include municipal gas distribution systems, public utility districts, county districts, and other public agencies that have natural gas distribution facilities.

Collectively, AGA and APGA members operate virtually all the investor-owned, publicly owned and community owned natural gas local distribution systems across all 50 states that are

[1] 88 Fed. Reg. 32,852 (May 22, 2023).
[2] For more information, please visit www.aga.org.

subject to reporting under EPA's GHG reporting program (GHGRP) and that will be directly affected by the proposed revisions to the gas distribution reporting rules. The Associations' members will also be affected by cost impacts on their gas supply due to the proposed revisions of the GHGRP reporting rules for natural gas transmission pipelines, transmission compression, and underground storage facilities. In addition, the Associations' members that operate state-regulated intrastate natural gas transmission, transmission compression, liquefied natural gas ("LNG") storage facilities, LNG import-export facilities, and underground storage facilities will be directly affected by the revised reporting requirements for such facilities in the Supplemental Notice.

As a result, AGA, APGA, and our members have a strong interest in the GHGRP and the Proposed Rule. This strong interest is demonstrated by our participation and comments in past GHGRP rulemakings, including EPA's June 2022 proposed rule that was a predecessor to this Supplemental Notice.[3] Although those comments were heavily focused on proposed revisions to Subpart W of the GHGRP, the proposed revisions included in the Supplemental Notice include other changes and modifications to the GHGRP of significant interest to natural gas distribution system operators. [4]

The Associations and our members have long supported measures for improving the transparency and accuracy of methane emissions reporting and for promoting best practices for reducing methane emissions. For example, AGA worked with members to develop a Blowdown Emission Reduction White Paper in 2020 to help share learnings and best practices.[5] AGA and many of our gas distribution members were founding participants in EPA's Natural Gas STAR program in 1993. AGA and our members have been committed to this voluntary technology and best practices program for reducing methane emissions for more than 20 years. AGA and our members also helped establish the EPA Methane Challenge program, which calls on participating companies to set challenging best management practice (BMP) goals for reducing methane emissions across their operations. Alternatively, participating companies have set goals for reducing emissions to achieve low methane emissions intensity levels under the ONE Future track of the Methane Challenge Program. All the founding natural gas distribution participants in Methane Challenge are AGA member companies. Additionally, over the past 30 years, many APGA members have joined the Methane Challenge Program, demonstrating their commitment to taking meaningful actions to reduce methane emissions. The methane emissions strategies our members shared in Natural Gas STAR and the commitments they made in the Methane Challenge program have helped to reduce methane emissions from U.S. natural gas distribution systems by 70 percent from 1990 to 2021, down to just 0.1 percent of annual produced natural gas, as shown in the April 2023 GHG Inventory for 1990-2021.[6]

The Associations and our members are also seeking to reduce methane emissions from our upstream suppliers through improving the accuracy and transparency of methane reporting. Working with institutional investors and non-governmental organizations ("NGOs"), AGA and

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[3] 87 Fed. Reg. 36,920 (June 21, 2022).

[4] The Associations have long advocated for allowing an option under Subpart W to report emissions based on direct measurements and company/utility-specific emission factors. Such an option would allow for more accurate quantification of actual emissions than is currently possible using EPA's default population-based emission factors.

[5] *See* AGA Blowdown Emission Reduction White Paper (2020) (Last accessed July 19, 2023).

[6] *See* 2023 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2021 (April 15, 2023)(2023 GHGI).

the Edison Electric Institute ("EEI") developed an Environmental, Social, Governance ("ESG") reporting template tailored to issues relevant to gas and electric utilities, including methane. To encourage upstream suppliers to publicly disclose their methane emissions in a robust and comparable way, we developed our Natural Gas Sustainability Initiative ("NGSI").[7] NGSI provides comprehensive methane intensity metrics for five segments of the natural gas supply chain: (1) production; (2) gathering and boosting; (3) processing; (4) transmission and storage; and (5) natural gas distribution. By publicizing their NGSI methane intensity, companies can be recognized for their leadership, providing a strong incentive for companies across the natural gas supply chain to reduce methane emissions.

NGSI is designed to be complementary to other efforts to reduce methane emissions and is intended to work in concert with regulatory standards. Ensuring that methane emissions from the natural gas supply chain are minimized is a critical part of our members' efforts to decarbonize. NGSI currently relies heavily on the default emission factors in EPA's Subpart W rule augmented by emission factors EPA uses in the annual EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks ("GHG Inventory").

The Associations' members are also taking action to reduce the carbon intensity of their delivered product by acquiring natural gas that has been certified as meeting stringent emission standards by independent third-party auditors. The number of new innovative certification products has expanded rapidly in the last several years. For example, Rocky Mountain Institute ("RMI") and SYSTEMIQ announced a new certified low methane gas standard in December 2020 called MiQ ("Methane Intelligence")[8] that incorporates the NGSI methane intensity metric for production coupled with monitoring on a semi-annual or quarterly basis to detect and fix any higher-emitting sources. There are also other certified lower methane gas platforms, including Equitable Origin's Energy Certification[9] and certification by an equipment vendor's initiative, Project Canary-Trustwell™[10] and its "Responsibly Sourced Gas" ("RSG"). An increasing number of producers announced in 2021 and earlier this year that they are obtaining third party certification under these standards to offer lower methane intensity natural gas.

The Associations will focus our comments on the Supplemental Notice affecting reporting for natural gas distribution facilities and certain other intrastate Subpart W facilities operated by our member natural gas local distribution companies ("LDCs").

1. Proposed Subpart B to Collect Energy Consumption Data Exceeds EPA's Authority Under The Clean Air Act and Will Not Provide EPA Useful Data.

In its 2022 Proposed Rule[11], EPA requested comment on whether the Agency should expand the GHGRP to require reporting of a source's onsite energy consumption. EPA's proposal stated that "facilities that are subject to the [rule] would be required to submit new,

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[7] *See* Natural Gas Sustainability Initiative (NGSI) - American Gas Association (aga.org) (last accessed July 19, 2023).
[8] *See* https://miq.org/ (last accessed July 19, 2023).
[9] *See* https://energystandards.org/ (last accessed July 19, 2022).
[10] *See* https://www.projectcanary.com/services/responsibly-sourced-gas/ (last accessed July 19, 2022).
[11] *See* "Proposed Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule," 87 Fed. Reg. 36920 (June 21, 2022).

summary data elements quantifying their consumption of purchased energy products and characterizing associated markets and products (*e.g.*, regulated or deregulated electricity markets and renewables attributes of purchased products)."[12] In its June 2022 Proposed Rule, EPA noted that it would not require quantification of indirect emissions, nor would these indirect emissions count towards GHGRP applicability for facilities. However, EPA did seek comment on whether the Agency should estimate indirect emissions using purchased energy data.[13] In its May 2023 Supplemental Proposal, EPA moves forward with adding new requirements for sources to report energy consumption data, including certain electricity purchases.[14] However, EPA is not, at this time, proposing to require estimation of any associated indirect emissions, nor has EPA asserted that it will use such data to make such estimates without first undertaking a separate rulemaking.[15]

Although the Associations agree with EPA's decision to not move forward with requiring quantification of indirect emissions, which are outside of EPA's regulatory authority,[16] EPA has not fully resolved the concerns raised over the scope of its statutory authority by limiting the Supplemental Proposal to energy consumption data. In its Supplemental Proposal, EPA attempts to address several concerns raised in response to its 2022 request for information about the collection of energy consumption data, particularly comments that focused on EPA's limited statutory authority to require collection of such data, by asserting an unspecified "policy" interest in this data as it may related to future regulations and the ability to regulate energy intensity. These attempts are unavailing. Congress has not authorized EPA to collect data for unspecified purposes untethered from its regulatory authority. EPA regulates direct emissions, not energy intensity, and its data collection authority must serve these purposes.[17]

[12] *Id.* at 37,018.

[13] *Id.*

[14] *See* 88 *Fed. Reg.* at 32,869 and 32,885-92. The Supplemental Notice preamble discusses different applicability criteria considered by EPA for Subpart B reporting. Alternative options considered are not warranted and will likely result in added complexity and confusion among reporting entities, with little or no benefit. For example, EPA considered, and opted not to propose, a lower annual emissions threshold for Subpart B reporting. Since such facilities are not integrated into the GHGRP, complexities would arise (e.g., regarding applicability determinations) with no indication that the added information on energy usage provides any meaningful benefit. The GHGRP already includes GHG emissions reporting from electricity generation, and Subpart B reporting may provide some limited insight into the demographics of how larger GHG emitters subject to GHGRP reporting contribute to associated electricity usage. Further detail from smaller or other facilities not currently subject to GHGRP reporting will provide minimal value to EPA and is not needed at this time.

[15] *See id*. at 32,887 and 32,888. Also, please note that a separate rulemaking, alone, does not sufficiently address the Associations' primary concern regarding estimates of indirect emissions: EPA does not currently have the statutory authority to regulate indirect emissions.

[16] Additionally, implementation of such a requirement would result in yet another conflicting regime for scope 2 emissions estimations.

[17] Indeed, with the exception of EGUs and the oil and gas production, transport, storage, and processing sectors, EPA has not proposed direct GHG emissions limitations for any source category. Moreover, EPA has ignored settlement agreements to move forward with such regulations in other sectors. Instead of focusing on data collection to serve speculative future efforts to possibly regulate these sources' energy consumption, EPA should consider directly regulating GHG emissions from these emitting sources first. Such regulations are squarely within EPA's authority, and while some sectors' indirect emissions from energy consumption might be greater than direct emissions, there are many unregulated source categories with significant direct emissions.

While energy consumption data might be useful to broader federal efforts to address climate change, this does not mean that EPA has unfettered authority to collect such information. Moreover, EPA cannot point to any provision of the CAA that provides the statutory authority to collect broad energy consumption data. However, if EPA decided to move forward with proposals to regulate direct emissions from a specific source category or type of affected sources, the Agency could collect needed data if it could show how such data was relevant to the establishment of emissions standards and limitations. Accordingly, the Associations strongly urge EPA to not finalize the proposal to collect energy consumption data under the GHGRP.

Even if EPA had the statutory authority to require the reporting of energy consumption data or related indirect emissions, the data that EPA proposes to collect will not help EPA accomplish the goals the Agency outlines for such data. As a result, it is not clear what benefit EPA would obtain in exchange for imposing this reporting burden. EPA's proposed energy consumption data collection requirements are too broad to be useful, particularly if the goal is to use this data to compare the energy intensity of different sources of the same type or class.

EPA asserts that energy consumption data "is essential for identifying the most energy efficient facilities within each sector." 88 *Fed. Reg*. at 32,887. EPA does not explain, however, how the proposed energy consumption data to be reported—which will be based on billing information for an entire facility, not just the emitting source that could be subject to regulation under EPA's CAA authority— actually will allow it to make those calculations in a way that could be considered sufficiently accurate to provide for meaningful energy efficiency comparisons.[18] It is unlikely that the emitting source that has to report energy consumption data based on contracted for, metered, and billed electricity is the only end use of electricity at that particular site.[19] Instead, it is much more likely that many end uses are "commingled" in one bill, including, for example, lighting, heating, and cooling, in addition to any electricity that might be used in a process that results in direct emissions.[20] Accordingly, EPA will have no ability, based on contracts and electricity bills, to parse how much electricity was consumed by the relevant emitting facility. To that end, while EPA claims that it can use "standard engineering

[18] As discussed above, EPA's regulatory authority is limited to addressing direct emissions. While this could include assessing the efficiency of a source's fuel consumption that results in direct emissions (e.g., the efficient consumption of natural gas by an EGU), EPA is not statutorily authorized to regulate the non-emitting use of fuels. This is committed to DOE under EPCA. Moreover, EPA has not addressed that energy consumption data could be considered by some competitors to be confidential business information. *See* 88 *Fed. Reg*. at 32,907-08 (no proposed confidentiality determinations for proposed Subpart B).

[19] EPA's proposed data reporting requirements are limited to those entities that have existing contracts for energy consumption. *See* proposed 40 C.F.R. § 98.20(b)(2). EPA uses the phrase "purchasing agreements" in this context but does not define this term. "Purchasing agreements" generally are not used between local distribution companies and their customers but are tools that are employed for wholesale purchases of power and by some larger commercial and industrial customers in states where such direct purchases of electricity are permitted by law. This would exclude a large number of sources that are otherwise required to report direct emissions under the GHGRP because they do not contract for electricity, but instead take service under the relevant tariff, as approved by the relevant public utility regulator. This places further limits on the comparability benefits of any data that could be collected. Even if EPA redefined the source category to include direct emitting source that receives an electricity bill, however, this would not overcome the challenges that EPA would have in using this data to make accurate energy intensity comparisons, as discussed in these comments.

[20] It may be important to recall here that consumption of electricity onsite to run equipment or processes does not result in any additional emissions (beyond those that were emitting when converting a fuel to electricity at an EGU).

calculations"[21] to make this data comparable to sector-specific direct emissions data, *see id.*, it is not at all clear how useful such comparisons would be given the inability to match usage to the relevant emitting facility. Although numerous commenters raised these concerns in response to last year's proposal; EPA has not addressed them in this Supplemental Proposal.

For the reasons detailed above, as well as those described at length in the EEI's detailed comments submitted to this docket, the Associations strongly urge EPA not to move forward with its proposal to require reporting of energy consumption data in new Subpart B.

2. EPA Should Exempt Natural Gas Distribution Facilities from Subpart B Requirements. Purchased Electricity is Minimal for this Segment and the Unique Nature of These Facilities Will Add Complexity and Administrative Burdens Not Fully Contemplated By EPA.

While in no way conceding EPA's statutory authority to require the reporting of energy consumption data as proposed in Subpart B, the Associations strongly urge EPA to exempt natural gas distribution facilities, if it opts to implement such a requirement in a final rule.

Natural gas distribution facilities possess unique characteristics and attributes that make them unique when compared to typical GHGRP facilities. EPA recognized these unique characteristics and attributes when it adopted a specific definition in Subpart W for "natural gas distribution" facilities that differs from the general definition of "facility" provided in Subpart A. Specifically, EPA defines a "natural gas distribution" in Subpart W as follows:

> *Natural gas distribution means the distribution pipelines and metering and regulating equipment at metering-regulating stations that are operated by a Local Distribution Company (LDC) within a single state that is regulated as a separate operating company by a public utility commission or that is operated as an independent municipally-owned distribution system. This segment also excludes customer meters and regulators, infrastructure, and pipelines (both interstate and intrastate) delivering natural gas directly to major industrial users and farm taps upstream of the local distribution company inlet.*[22]

The data sought to be collected under new Subpart B - electricity consumption – along a natural gas distribution system is relatively minor, with the potential for multiple electricity providers spanning across a utility's service territory. Billing cycles, usage periods, and other variables may vary by provider. As a result, this will likely result in significant complexity and administrative burden for natural gas utilities to gather multiple small bills and determine which portions of those bills are allocated to the natural gas distribution facility, as defined in Subpart W, to capture and report small amounts of electricity usage.[23] Additionally, the requirements in

[21] EPA provides no examples of such calculations, so it is impossible to assess whether those calculations actually provide useful data or are otherwise appropriate to achieve EPA's stated goals.

[22] *See* 40 C.F.R. §98.230.

[23] Further complicating the allocation of energy costs at a natural gas facility required to report under Subpart W, many of these facilities are jointly utilized by multiple utilities (e.g., gas and electric, gas and water, or gas, electric, and water).

Subpart B to develop a MEMP would also create additional administrative burdens on natural gas LDCs, with minimal benefits to EPA or the public.

Finally, for the reasons identified in their comments, the Associations support the Interstate Natural Gas Association of America's ("INGAA's") request that the onshore natural gas segment also be exempt from the Subpart B reporting requirements.

3. EPA Should Ensure that GHGRP Data Releases Subsequent to Any Update to Global Warming Potential (GWP) for Methane and N_2O Include a Clear Explanation Regarding Resulting Apparent but Not Actual Increases in Annual Methane Emissions Reported.

The Supplemental Notice proposes to update global warming potential (GWP) values and references the 100-year time horizon GWP from Table 8.A.1 of the IPCC Fifth Assessment Report ("AR5") for methane and N_2O. The Associations understand these updates are being completed to ensure consistency across EPA programs and with international reporting conventions. The Associations also understand that this update is necessary to ensure consistency with other national and international reporting regimes and supports using the 100-year basis for GWP. Some state programs and analysis in the literature consider other time horizons (e.g., 20 years), but it is appropriate for EPA and other federal programs to retain the 100-year basis for GWP.

For reporting, unless offset by a reduction in year-to-year methane emissions, this revision will result in an apparent "increase" in annual CO_2 equivalent methane emissions from natural gas operations, even if there is no actual emissions increase or even a decrease in actual emissions. Such reporting changes can be misconstrued by the public and third parties that review EPA data and documentation. To avoid unfounded concerns about emission trends and in an effort to provide the most accurate and accessible information, when publicly releasing GHGRP data following the GWP change, EPA should clearly communicate to the public and other stakeholder the implications of GWP on annual emission increases that are due to this computational change rather than an actual increase in methane emissions.

4. EPA Should Clearly Indicate That Emergency Generators Are Exempt from the New Requirements Under Subpart C.

For combustion emissions, the Supplemental Notice amends Subpart C to add an estimate of combustion emissions from facility electricity generation. EPA should clearly indicate that emergency generators are exempt from this requirement. Subpart C currently exempts emergency generators, and EPA should retain that exemption and clearly indicate that electricity from emergency generator use is not subject to this new reporting requirement.

When estimating emissions from electricity generation, the Associations support the proposed approach[24] that allows operators to use an engineering estimate of the percentage of combustion emissions attributable to facility electricity generation. The proposed amendments retain the ability to use aggregate, common stack, or common pipe methods for reporting

[24] See § 98.36(c)(1)(xii), (c)(2)(xii) and (c)(3)(xii) at 88 FR 32,926.

combustion emissions, and one of those methods is typically used for Subpart C combustion emission estimates at affected natural gas transmission compressor stations and storage facilities. There will typically be little or no electricity generation at these facilities, but some include auxiliary power generators. An engineering estimate is adequate for reporting the share of emissions from electricity generation, and more complex or rigorous methods are not warranted.

5. EPA Should Clarify Some of the Proposed Revised Reporting Requirements for Hydrogen Producers, Including Whether Some of the Data to Be Collected is CBI.

For Subpart P, which addresses reporting requirements for hydrogen production, EPA proposes several amendments.[25] While the Associations generally support the Agency's amendments, particularly given increased interest in hydrogen as a potential GHG reductions tool for some emitting sources, certain aspects of EPA's proposed amendments are of concern, as noted below.

First, EPA is proposing to require reporting of the annual net quantity of steam consumed per unit. However, the Agency does not provide its rationale for this proposal or indicate how it would use this information in its calculations. EPA should provide its justification for this proposal and clarify how the information would be used. To ensure that there is adequate opportunity for notice and comment on this proposal, it may be necessary for EPA to issue an additional supplemental notice of proposed rulemaking to take comment on any such justification.

Second, EPA is also proposing to remove the "off-ramp" for facilities that otherwise could stop reporting (if annual emissions were under 15,000 after three years or between 15,000 and 25,000 after five years).[26] Again, EPA does not provide any justification for the proposed removal of this "off-ramp." In addition, EPA ignores that this "off-ramp" is intended for entities that should no longer be subject to reporting requirements under the rule by virtue of the fact that their emissions fall below a reasonable threshold. It is not clear how EPA would have the authority to continue to require reporting for these entities, and EPA's interest in upstream emissions related to hydrogen production is not sufficient to overcome a lack of regulatory authority justifying the collection of such data.[27] If EPA plans to move forward with a proposal along these lines, it should provide justification for its proposal and a proposed rule on which interested parties may provide comment.

Finally, EPA proposes to collect sales information. EPA similarly does not provide justification for this proposal. Inexplicably, while this proposal targets information that very likely could be sensitive, particularly given that the hydrogen economy is developing and prices are likely to have significant variability as users compete for a scarce product, EPA does not propose any

[25] *See generally* 88 *Fed. Reg*. at 32,874-77.
[26] *See id*. at 32,876.
[27] EPA could propose a separate standard addressing emissions from hydrogen production under CAA 111. This would be more appropriate than attempting data collection fishing expeditions. If EPA needed to data to develop such standards, the Agency has other tools, outside of the GHGRP, to collect it. Moreover, EPA already has proposed to require EGUs to limit their use of hydrogen to "low GHG hydrogen" for purposes of compliance with the Proposed Section 111 Rules.

protection for this data.[28] EPA's failure to provide a confidential determination for this highly sensitive data could be because it is not an input to any emissions equation. If that is the case, EPA should consider whether such sensitive data is relevant to EPA's data collection authorities and whether it should be collected at all.

The Associations appreciate the opportunity to comment on this matter and offer the foregoing comments to assist EPA in its ongoing effort to improve the GHGRP. If you have any questions, please contact us at the contact information provided below.

Respectfully Submitted,

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[28] *See* Memorandum to the Docket, From Jennifer Bohman, Proposed Reporting Determinations for Data Elements Assigned to the Inputs to Emission Equations Data Category in Proposed Supplemental Revisions to the Greenhouse Gas Reporting Rule (May 2, 2023).

AGA and APGA's Comments on
"Waste Emissions Charge for Petroleum and Natural Gas Systems"
Docket ID No. EPA-HQ-OAR-2023-0434

Attachment 5:
AGA and APGA Comments on
August 2023 Subpart W Proposal

Submitted via regulations.gov

October 2, 2023

U.S. Environmental Protection Agency
EPA Docket Center
Air and Radiation Docket
Mail Code 28221T
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Re: AGA and APGA's Comments on "Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems," Docket ID No. EPA-HQ-OAR-2023-0234

The American Gas Association ("AGA") and the American Public Gas Association ("APGA") (jointly, "the Associations") appreciate the opportunity to comment on the U.S. Environmental Protection Agency's ("EPA" or "Agency") proposed rule titled "Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems" ("Proposed Rule"), which was published in the *Federal Register* on August 1, 2023.[1] The Associations support certain concepts in the Proposed Rule—particularly the proposal to allow the development of site-specific emission factors and emissions reporting based on direct measurements—however, the Associations have a number of recommendations to improve the accuracy and ease of reporting by local distribution companies ("LDCs")[2] under Subpart W of the Greenhouse Gas Reporting Program ("GHGRP"), which would in turn incentivize methane emission reductions.

I. INTRODUCTION

AGA, founded in 1918, represents more than 200 local energy companies that deliver safe and reliable natural gas throughout the country. There are more than 78 million residential, commercial, and industrial natural gas customers in the United States, of which 96 percent—more than 74 million customers—receive their gas from AGA members. AGA is an advocate for natural gas utility companies and their customers and provides a broad range of programs and services for member natural gas pipelines, marketers, gatherers, international natural gas companies, and industry associates. Today, natural gas meets more than one third of United States energy needs.[3]

APGA is the national, non-profit association of publicly owned natural gas distribution systems. APGA was formed in 1961 as a non-profit, non-partisan organization, and currently has

[1] Proposed Rule, 88 Fed. Reg. 50,282 (Aug. 1, 2023).
[2] Most AGA members are investor-owned LDCs, and APGA members are municipal or publicly owned utilities. Consistent with the definition of "natural gas distribution" under Subpart W, *see* 40 C.F.R. § 98.230(a)(8), the term "LDC" is used throughout these comments to refer to both publicly and privately owned natural gas distribution entities (*i.e.*, members of both AGA and APGA).
[3] For more information, please visit www.aga.org.

over 740 members in 37 states. Overall, there are nearly 1,000 municipally owned systems in the United States serving more than five million customers. Publicly owned gas systems are not-for-profit retail distribution entities that are owned by, and accountable to, the citizens they serve. They include municipal gas distribution systems, public utility districts, county districts, and other public agencies that have natural gas distribution facilities.[4]

Collectively, AGA and APGA members operate virtually all of the investor-owned, publicly owned, and community-owned natural gas local distribution systems across all 50 states that are subject to reporting under the GHGRP. Accordingly, AGA and APGA members would be directly affected by the proposed revisions to the gas distribution reporting rules at 40 C.F.R. Part 98, Subpart W. The Associations' members would also be affected by cost impacts on their gas supply due to the proposed Subpart W revisions pertaining to onshore natural gas transmission pipelines, onshore gas transmission compression, and underground natural gas storage facilities. In addition, Association members that operate state-regulated intrastate natural gas transmission, transmission compression, liquefied natural gas ("LNG") storage facilities, LNG import-export facilities, and underground storage facilities would be directly affected by the revised reporting requirements for such facilities in the Proposed Rule.

As a result, AGA, APGA, and our members are deeply invested in the GHGRP and the Proposed Rule. This strong interest is demonstrated by our participation and comments in GHGRP rulemakings over the past year, including the June 2022 proposed rule to address data quality, consistency, and gaps across the GHGRP as a whole ("2022 Proposal");[5] the November 2022 Request for Information ("RFI") to inform EPA's implementation of new Section 136 of the Clean Air Act, which was added by Section 60113 of the Inflation Reduction Act of 2022 ("IRA");[6] and the May 2023 supplement to the 2022 Proposal that, among other things, would require reporting of energy consumption data under new Subpart B and revise global warming potentials ("GWPs") for the GHGRP ("2023 Supplemental Proposal").[7] Additionally, AGA has filed comments in every round of Subpart W rulemaking related to the oil and natural gas source category since 2008, and APGA has filed comments in each round of Subpart W rulemaking since the initial Subpart W proposal in 2009.

The Associations and our members have long supported measures for improving the transparency and accuracy of methane emissions reporting and promoting best practices for reducing methane emissions. For example, AGA worked with members to develop a Blowdown Emission Reduction White Paper in 2020 to help share learnings and best practices.[8] AGA and many of our gas distribution members were founding participants in EPA's Natural Gas STAR program in 1993, and have remained committed to this voluntary technology and best practices program since its inception. AGA and our members also helped establish the EPA Methane

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[4] For more information, please visit www.apga.org.
[5] *See* 87 Fed. Reg. 36,920 (June 21, 2022); AGA and APGA Comments on 2022 Proposal (Oct. 6, 2022), https://www.regulations.gov/comment/EPA-HQ-OAR-2019-0424-0236.
[6] *See* AGA Comments on Inflation Reduction Act Section 60113 RFI (Jan. 18, 2023), https://www.regulations.gov/comment/EPA-HQ-OAR-2022-0875-0035.
[7] *See* 88 Fed. Reg. 32,852 (May 22, 2023); AGA and APGA Comments on 2023 Supplemental Proposal (July 21, 2023), https://www.regulations.gov/comment/EPA-HQ-OAR-2019-0424-0318.
[8] *See* AGA, Blowdown Emission Reduction White Paper (Aug. 5, 2020), https://www.aga.org/wp-content/uploads/2022/12/aga-blowdown-emissions-reduction-white-paper-final-8.5.20.pdf.

Challenge Program, which calls on participating companies to make commitments via one or both of the following options: (1) implementing one or more of EPA's recommended Best Management Practices for reducing methane emissions across company operations, and/or (2) reducing methane emissions to target rates established by the Our Nation's Energy ("ONE") Future Coalition. All of the founding natural gas distribution participants in the Methane Challenge are AGA member companies. Additionally, over the past 30 years, APGA members have participated in the Natural Gas STAR Program (launched in 1993) and subsequently in the Methane Challenge Program (launched in 2016), demonstrating their commitment to taking meaningful actions to reduce methane emissions. The methane emissions strategies that Association members have shared in Natural Gas STAR and the commitments they have made in the Methane Challenge Program have helped to reduce methane emissions from U.S. natural gas distribution systems by 70 percent from 1990 to 2021.[9] This brought the natural gas distribution segment's methane emissions down to a mere 0.12 percent of throughput in 2021, based on EPA's 2023 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2021 ("GHG Inventory") and data from the U.S. Energy Information Administration on total natural gas deliveries.[10] In addition, many Association members have made individual pledges to reduce their methane emissions and are working to incorporate process improvements and deploy methane detection and direct-measurement technologies to carry out those pledges.

The Associations and our members are also seeking to reduce methane emissions from our upstream suppliers by improving the accuracy and transparency of methane reporting. Working with institutional investors and non-governmental organizations, AGA and the Edison Electric Institute ("EEI") developed an Environmental, Social, Governance ("ESG") and Sustainability reporting template tailored to issues relevant to gas and electric utilities, including methane emissions.[11] To encourage upstream suppliers to publicly disclose their methane emissions in a robust and comparable way, AGA and EEI also developed the Natural Gas Sustainability Initiative ("NGSI") Methane Emissions Intensity Protocol ("Protocol").[12] The NGSI Protocol provides comprehensive methane intensity metrics for five segments of the natural gas supply chain: (1) onshore production, (2) gathering and boosting, (3) processing, (4) transmission and storage, and (5) natural gas distribution. By publicizing their NGSI methane intensity—a measure of methane emissions relative to natural gas throughput—companies can be recognized for their leadership, which provides a strong incentive for companies across the natural gas supply chain to reduce their methane emissions.

The ESG/Sustainability template and NGSI are designed to be complementary to other efforts to reduce methane emissions and work in concert with regulatory standards. Ensuring that methane emissions from the natural gas supply chain are minimized is a critical part of our

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[9] *See* EPA, 2023 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2021, at 3-95 (Apr. 15, 2023), https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2021.

[10] *See* AGA, Understanding Greenhouse Gas Emissions from Natural Gas – EPA 2023 Inventory (1990–2021) at 18 – Table 9 (Aug. 15, 2023), https://www.aga.org/wp-content/uploads/2023/09/AGA-Report_Understanding-GHG-Emssions-from-Natural -Gas_2023.pdf.

[11] *See* AGA and EEI ESG/Sustainability Templates, https://www.aga.org/research-policy/natural-gas-esg-sustainability and https://www.eei.org/issues-and-policy/esg-sustainability (last accessed Sept. 16, 2023).

[12] *See* AGA and EEI Natural Gas Sustainability Initiative, https://www.aga.org/research-policy/natural-gas-esg-sustainability/natural-gas-sustainability-initiative-ngsi and https://www.eei.org/issues-and-policy/NGSI (last accessed Sept. 16, 2023).

members' efforts to decarbonize. Version 3 of the ESG/Sustainability template, which is the most recent version, is based on emissions and sources reported to EPA under Subpart W of the GHGRP. Similarly, NGSI relies heavily on the default emission factors in the current Subpart W rule, augmented by the emission factors EPA uses in the GHG Inventory.

APGA's members formalized their commitment to reduce methane emissions through the APGA Commitment to Environmental Stewardship.[13] The commitment contains ten actionable elements intended to aid methane emission reduction by publicly and community-owned gas systems. These include incorporating best practices for methane emission mitigation at metering-regulating ("M&R") stations and city gate stations where appropriate and feasible, and replacing aging infrastructure that is known to have a higher probability of methane leaks.[14] APGA also developed an Environmental Roadmap for public gas systems, which is enclosed as **Appendix A**.[15] The Roadmap is a voluntary, written, qualitative assessment tool for public gas systems to determine the utility-specific status of environmental stewardship, compare environmentally sustainable actions and obtain ideas from other LDCs, facilitate communication of utilities' positive actions and initiatives to drive down methane emissions, and help set goals for continuous environmental sustainability efforts.

In states and communities that recognize and allow certified natural gas, the Associations' members are taking action to reduce the carbon intensity of their delivered product by acquiring natural gas that has been certified as meeting stringent emission standards by independent third-party auditors. The number of new innovative certification products has expanded rapidly in the last several years. For example, in December 2020, Rocky Mountain Institute and Systemiq announced a new certified low methane gas standard called MiQ ("Methane Intelligence"),[16] which incorporates the NGSI methane intensity metric for the production segment coupled with monitoring on a semi-annual or quarterly basis to detect and fix any higher-emitting sources. There also are other certified lower-methane gas programs, including Equitable Origin's EO100™ Standard for Responsible Energy Development[17] and Project Canary's Responsibly Sourced Gas ("RSG").[18] An increasing number of producers have announced that they are obtaining third-party certification under these standards to offer lower-methane intensity natural gas.

The Associations' commitment to reducing methane emissions throughout the natural gas value chain while increasing transparency in disclosure of our industry's GHG emissions is both well demonstrated and unwavering. Our comments on the Proposed Rule focus on opportunities for improving Subpart W with regard to the natural gas distribution segment and the facilities operated by AGA and APGA member LDCs. And, as noted above, because our members support measures to decrease GHG emissions and increase disclosure from upstream segments, we also

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[13] *See* APGA Press Release: APGA Members Are Committed to Environmental Stewardship (Aug. 3, 2021), https://www.apga.org/viewdocument/apga-members-are-committed-to-envir.

[14] *See* APGA, Excellence in Excellence in Environmental Stewardship Award, https://www.apga.org/programs/awards/environmental-sustainability-award (last accessed Sept. 29, 2023).

[15] *See* APGA, Environmental Roadmap (May 30, 2023), http://www.apga.org/resources/environmental-roadmap (enclosed as Appendix A).

[16] *See* MiQ, https://miq.org (last accessed Sept. 16, 2023).

[17] *See* Equitable Origin, EO100™ Certification Process, https://energystandards.org/eo100-certification-process (last accessed Sept. 16, 2023).

[18] *See* Project Canary, Responsibly Sourced Gas, https://www.projectcanary.com/next-gen-energy/responsibly-sourced-gas (last accessed Sept. 16, 2023).

support the comments filed by the Interstate Natural Gas Association of America ("INGAA") regarding proposed Subpart W changes for natural gas transmission, storage, and LNG facilities.

II. COMMENTS

The IRA amended the Clean Air Act to add new Section 136, titled "Methane Emissions and Waste Reduction Incentive Program for Petroleum and Natural Gas Systems" and codified at 42 U.S.C. § 7436. Section 136(c) requires EPA to collect a fee on methane ("CH_4") emissions from certain petroleum and natural gas facilities that report their emissions under Subpart W of the GHGRP.[19] Section 136(h) requires EPA to revise Subpart W by August 16, 2024, to ensure that both GHG reporting and the calculation of methane fees under Section 136(c) "are based on empirical data, . . . accurately reflect the total methane emissions and waste emissions from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data" to demonstrate the extent to which a methane fee is owed.[20]

Under Section 136(f), the natural gas distribution segment is not subject to the methane fee.[21] However, because LDC facilities that emit at least 25,000 metric tons of CO_2 equivalent ("mtCO_2e") per year must annually report their GHG emissions under Subpart W, members of AGA and APGA would be affected by any changes resulting from the Proposed Rule.

The Associations are committed to the IRA's goals of enhancing the accuracy of methane emissions quantification and incentivizing emission reductions, and we welcome the opportunity to collaborate with EPA to achieve them. Accordingly, the Associations offer the following comments on behalf of Subpart W reporters in the natural gas distribution segment.

A. The Associations support EPA's proposal to allow utilities to report emissions based on certain direct measurements; however, EPA should expand these options to include more measurement technologies and apply to additional source types, as this would increase reporting accuracy, provide greater flexibility to reporting facilities, and incentivize methane emission reductions.

As a general matter, the Associations are pleased that EPA is proposing to allow entities in the natural gas value chain to use site-specific direct measurements and emission factors to calculate certain reported emissions. The Associations provide more detailed feedback on individual, source-specific aspects of these proposals throughout our comments, but at the outset we encourage EPA to allow broader flexibility for using an array of measurement technologies so that Subpart W reporters can select the empirical tool that is appropriate for each task. Further, to improve data accuracy across the board, we request that EPA allow gas distribution reporters to develop company/utility-specific activity factors wherever possible.

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[19] 42 U.S.C. § 7436(c).

[20] *Id.* § 7436(h).

[21] *See id.* § 7436(f) (natural gas distribution not included in the list of nine oil and natural gas industry segments that are subject to the methane fee).

1. **The revisions to Subpart W should facilitate the development of new methane detection and measurement technologies and allow their use in GHGRP reporting.**

There are many tools now available in the methane detection and quantification toolbox, with more options being developed and refined, and it is important for companies/utilities to be able to pick the appropriate tool or mix of tools for the job at hand. Top-down measures like advanced mobile detection platform ("AMLD") methodology show promise for quantifying the overall methane emissions from all leaks in a gas utility's entire system when deployed with multiple passes of the mobile platform (*i.e.*, by car, drone, airplane, or satellite) in conjunction with a robust, statistically valid sample of direct measurement data. AMLD opens up a new possibility of quantifying the collective methane emissions of a utility's *system-wide* operations across all assets with a high level of certainty—in particular, it can be quite useful for detecting leaks over large swaths of natural gas assets so those leaks can be prioritized for repairs. Some current top-down methods have limitations, including that certain AMLD technologies may not provide the best quantification of emissions from individual leaks or specific types of sources, while other AMLD options are currently too costly for quick adoption by all companies/utilities. However, top-down technologies are rapidly improving and costs are expected to decrease as more deployment occurs, data is gathered and studied, and algorithms are adjusted. Technologies like top-down AMLD are beneficial but may need to be used in conjunction with traditional bottom-up technologies to provide the most accurate leak detection and quantification reporting. The benefits and drawbacks of current AMLD technology represent just one example of the need for flexible treatment of emerging technologies under Subpart W.

EPA should establish pathways for integrating new methane detection and measurement technologies into Subpart W in order to facilitate ongoing innovation and improvement in this rapidly evolving field while also increasing the accuracy of emissions reporting. Currently, the options for allowing new technologies in Subpart W reporting both involve long lead times and extensive process: EPA can conduct a rulemaking to revise Subpart W or reporters can engage in a laborious, multi-year petition process to obtain permission to use an alternative technology. Neither of these options can occur swiftly, making it nearly impossible for Subpart W to keep up with rapid and meaningful developments in leak detection and direct measurement technology. To remedy this, EPA should define a protocol for accepting new technologies that meet certain performance criteria. For example, a new technology could be deemed presumptively approvable if it shows results within specified ranges of accuracy and confidence levels in a requisite number of side-by-side tests conducted with an already-approved technology. EPA could establish an expert panel that reviews the results and confirms that the criteria is met for using a particular technology for a particular purpose, as specified in an applicant's request for approval. The panel could be given a reasonable deadline within which to decide whether to accept a new technology for use in Subpart W reporting; if a decision is not timely made by the panel, the technology would automatically be approved.

Alternatively, EPA could allow companies/utilities to pilot emerging technologies through best available monitoring method ("BAMM") provisions akin to what EPA provided when Subpart W was first implemented. Technologies like AMLD may still be costly and sophisticated compared with traditional methods, so they may be best introduced by well-resourced utilities in targeted pilot programs. A BAMM or similar pilot option would further build the record for more mainstream acceptance of new technologies in Subpart W reporting. And, as the natural gas industry gains experience with new technologies and more utilities participate, economies of scale should help make this method more accessible to smaller gas utilities—particularly municipal or publicly owned utilities with more limited budgets. A similar pilot-type mechanism could be established by reference to the technological approvals of an outside standard-setting entity, such as American Society for Testing and Materials ("ASTM") International. EPA also should coordinate with the Department of Energy ("DOE") to incorporate the results of DOE-funded research projects aiming to advance the development of new and innovative measurement, monitoring, and mitigation technologies for methane emissions.[22]

As established by the IRA, Section 136(a) of the Clean Air Act authorizes $850 million in federal funding for, among other things, financial and technical assistance to help owners and operators of applicable facilities prepare and submit their Subpart W reports; EPA-led research, testing, and development of methods for sampling, measuring, and monitoring air pollutants pursuant to Section 103; and EPA's direct and indirect costs of administering Section 136, gathering empirical data, and tracking emissions.[23] If EPA develops a streamlined pathway for obtaining Subpart W approval of new emissions monitoring technology, the Agency could use this IRA funding to not only facilitate owner/operators putting new technologies into practice such that they can gain traction in the sector, but also can use this funding for EPA's own administration of the new-technology approval program. The Section 136(a) funding is only available through September 30, 2028; the limited window to leverage this funding in connection with Subpart W monitoring is yet another reason EPA should enable a faster approval process for using new technology to gather empirical data for Subpart W reporting.

2. **EPA should allow for a broader use of site-specific, company/utility-specific, or collaboratively developed inter-company/utility emission factors based on direct measurements of emission sources.**

Whether via newly approved or well-established measurement technologies, EPA should allow the use of direct data in the development of site-specific, company/utility-specific, or even inter-company/utility collaboratively developed emission factors for as many types of sources as possible. Activity factors based on each reporter's own facilities are more accurate than national average emission factors because they reflect each facility's real-life emissions—including emission reductions. Allowing companies/utilities to accurately demonstrate the emission reductions achieved via improved monitoring, leak detection, and repair methods is itself an incentive to achieve greater reductions and creates a more accurate emissions inventory. Conversely, default emission factors do not allow a company to demonstrate its actual emission reductions. Particularly with population-based default emission factors (*i.e.*, those multiplied by miles of pipe or numbers of components), this problem is compounded when a utility expands its natural gas system to serve more customers or improve reliability. In that scenario, the additional miles of pipe or number of pressure-regulating stations will result in the calculation and reporting of what appears to be an increase in methane emissions—even if *actual* emissions declined due to the use of best practices and improved pipeline materials.

[22] DOE Press Release: DOE Invests $47 Million to Reduce Methane Emissions From Oil and Gas Sector (Mar. 13, 2023), https://www.energy.gov/articles/doe-invests-47-million-reduce-methane-emissions-oil-and-gas-sector.
[23] 42 U.S.C. § 7436(a).

Further, enabling Subpart W reporters to use emission factors that are collaboratively developed by multiple companies can open up Section 136(a) funding for these projects, which fosters cooperative innovation to the benefit of the industry at large. Making it possible to use this funding for creative methods to improve emissions estimates and increase the use of empirical data for Subpart W reporting would align perfectly with the objectives of Section 136 of the Clean Air Act. Conversely, forcing Subpart W reporters to use generic emission factors instead of data derived from direct measurement can act as a disincentive—particularly for the distribution segment, which is currently required to use emission factors that often are based on data from other, higher-emitting segments,[24] thereby inflating the amount of GHG emissions attributable to distribution equipment. In sum, EPA should allow companies sufficient flexibility to select technologies and calculation methodologies that will yield useful, more accurate empirical data.

B. The Associations support EPA's proposed methods of quantifying distribution segment equipment leaks via population count but offer additional recommendations for further improving the proposed methods.

EPA is proposing to revise the distribution segment emission factors used to quantify equipment leaks via population count under Subpart W. As it applies to the distribution segment, the population count method currently uses (1) the count of equipment components, counted individually for each facility; (2) the Subpart W population emission factors in Table W-7; and (3) the time that the equipment was operational. EPA is proposing to update the population emission factors for pipeline mains and services, below-grade transmission-distribution ("T-D") transfer stations, and below-grade M&R stations in Table W-7 (and move these emission factors to Table W-5) using the results of newer study data.[25] Notably, the proposed population emission factors for distribution mains and services rely on direct flow measurements from the 2015 Lamb et al. study ("Lamb Study")[26] and do not incorporate leak frequency estimates from the 2020 Weller et al. study ("Weller Study")[27]—this is consistent with the approach that the Associations have previously urged EPA to adopt. The Associations also support EPA's proposal to incorporate data from the Lamb Study into the population emission factors for below-grade stations. However, the Associations encourage EPA to give owners and operators the option to develop site-specific or company/utility-specific emission factors, as this would further increase the accuracy of emissions reported under Subpart W.

1. It is appropriate for EPA to use the Lamb Study to develop population emission factors for distribution mains and services.

The Associations have identified several significant limitations to the Weller Study that preclude it from being a reasonable basis for natural gas distribution factors, as well as several reasons why EPA should adopt the proposed distribution factors based on the Lamb Study. These

[24] According to the 2023 GHG Inventory, only about 7 percent of total GHG emissions from the natural gas value chain were attributable to the distribution segment in 2021. *See* GHG Inventory at 3-95 (Table 3-65).
[25] Proposed Rule, 88 Fed. Reg. at 50,349–54.
[26] B.K. Lamb et al., *Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States*, 49 ENVIRON. SCI. TECHNOL. 8 at 5161–69 (Mar. 31, 2015), https://pubs.acs.org/doi/10.1021/es505116p.
[27] Z.D. Weller et al., *A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems*, 54 ENVIRON. SCI. TECHNOL. 14 at 8491–9144 (June 10, 2020), https://pubs.acs.org/doi/full/10.1021/acs.est.0c00437.

attributes are summarized below and discussed in greater depth in the Associations' comments on the 2022 Proposal, which are enclosed as **Appendix B**.[28]

As to the Weller Study, although it had a larger sample size than the Lamb Study, it has key disadvantages, including that it: (1) did not distinguish between cathodically protected and cathodically unprotected steel pipe, which means that leak data for the more leak-prone cathodically unprotected pipe was arbitrarily combined with data for cathodically protected pipe; (2) assumed that all emissions were derived from gas main leaks, instead of distinguishing between distribution mains and service lines, which artificially inflated the leak factors for mains because their emissions were grouped in with those from services; (3) used AMLD methodology that, despite showing promise for the development of system-specific emission factors, is not precise enough to develop accurate emission factors for different types of pipe material; (4) was based on limited data from only four cities and did not distinguish between urban, suburban, and rural areas, which is insufficient geographic diversity for extrapolating the data to construct nationwide emission factors; (5) exhibited a high degree of uncertainty in correlating flow rate field results with flow rate control test results; (6) did not distinguish between biogenic and thermogenic sources of methane, thereby inflating emissions and leak rates from natural gas distribution systems; and (7) used minimal verification for leak locations by assuming that a leak indication within 40 meters of a distribution pipeline must be associated with the pipeline, instead of considering how wind direction or obstructions (*e.g.*, trees, buildings) could affect the perceived location of a leak. It is particularly important for the population emission factors to be based on data that differentiates by cathodic protection because EPA's Methane Challenge Program incentivizes natural gas distribution companies and municipal utilities to replace unprotected steel pipe with cathodically protected steel pipe as a means to reduce leaks. Use of emission factors that do not recognize the lower methane emissions from protected steel would undermine this incentive.

The Associations support EPA's use of the Lamb Study to develop Subpart W population emission factors because the study is the best currently available basis for default national average emission factors for the distribution segment. Using the Lamb Study would improve the accuracy of reported distribution segment emissions for several reasons, including that the study: (1) reduced uncertainty through direct measurements by using a high-volume sampler methodology, which is an appropriate approach for measuring flow rates from leaks and developing emission factors for specific types of pipe materials; (2) was more geographically diverse, and therefore more representative of gas utilities across the country than the Weller Study, because it included nationwide data from thirteen cities across the country in different climates, population densities, and distribution system configurations; (3) verified leak locations before measurement by using standard, reliable leak detection methods to identify the exact area of a leak; and (4) verified pipe material and distinguished between cathodically protected and cathodically unprotected steel pipe, which was possible because the study authors worked with system operators to obtain site access, pipe asset and operations information, and direct viewing of pipes during excavations conducted for repair work. Furthermore, because the Lamb Study is already used in EPA's annual GHG

[28] *See* AGA and APGA Comments on 2022 Proposal at 10–18 (Oct. 6, 2022), https://www.regulations.gov/comment/EPA-HQ-OAR-2019-0424-0236 (enclosed as Appendix B).

Inventory, the study's use in population-based emission factors for gas distribution mains and services would promote consistency between Subpart W and the GHG Inventory.

The current population emission factors for distribution pipeline mains and services are based on information from a 1996 Gas Research Institute/EPA study ("GRI/EPA Study"),[29] with additional data on plastic mains sourced from a 2005 ICF analysis.[30] For the revised emission factors for mains and services, EPA is proposing to rely on leak rates from the Lamb Study and leak incidence data from the 1996 GRI/EPA Study.[31] The Associations request that EPA rely *only* on the Lamb Study to revise these emission factors, as the Lamb Study is more recent and therefore better accounts for the improved leak detection and repair ("LDAR") best practices applied by Association members in the years since the 1996 GRI/EPA Study. This, in turn, would make the distribution mains and services emission factors more accurate than what is currently proposed, which would align with Congress's directive to EPA in the IRA.

2. **It is appropriate for EPA to use the Lamb Study to develop population emission factors for below-grade stations.**

The current population emission factors for below-grade stations are based on the 1996 GRI/EPA Study, with T-D emission factors distinguished by station component and M&R station emission factors distinguished by inlet pressure. EPA is proposing to incorporate the Lamb Study data by establishing a single emission factor for both types of below-grade stations (T-Ds and M&Rs), without regard to inlet pressure. For the reasons discussed above, the Associations support the use of the Lamb Study for these emission factors because they would facilitate a more accurate reporting of distribution segment GHG emissions. Further, the Associations support the ancillary benefit of reduced reported data elements.[32]

3. **EPA should provide an option for companies/utilities to develop their own emission factors, which would allow for even more accurate reporting and incentivize further reductions of GHG emissions from distribution mains, services, and below-grade stations.**

With regard to default national emission factors, the Associations support EPA's proposed methodology based on the Lamb Study. However, we believe that EPA should also provide an option for companies/utilities to develop their own emission factors for distribution mains,

[29] The 1996 GRI/EPA Study is presented in different volumes. The two that are relevant to Section G of the Associations' comments are: GRI/EPA, *Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines*, GRI–94/0257.2b, EPA–600/R–96–080i (June 1996), https://tinyurl.com/1996-GRI-EPA-vol9; GRI/EPA, *Methane Emissions from the Natural Gas Industry, Volume 10: Metering and Pressure Regulating Stations in Natural Gas Transmission and Distribution*, GRI–94/0257.27, EPA–600/R–96–080j (June 1996), https://tinyurl.com/1996-GRI-EPA-vol10.

[30] *Fugitive Emissions from Plastic Pipe*, Memorandum from H. Mallya and Z. Schaffer, ICF Consulting to L. Hanle and E. Scheehle, EPA (June 30, 2005), https://www.regulations.gov/document/EPA-HQ-OAR-2023-0234-0019.

[31] The Associations note that EPA did not explain why it proposes to rely on leak incidence data from the 1996 GRI/EPA Study instead of leak incidence data from the Lamb Study.

[32] The Associations note that, while a reduction in reporting burden is appreciated as a general matter, we support it in scenarios such as this one, where the accuracy of the emissions data is not inconsistent with the reduction in reporting elements. In contrast, we would not support a reduction in reportable elements just for the sake of reducing burden when they would also reduce accuracy—for example, if reporting obligations did not allow for identifying differences in pipe material where such differences have an impact on the estimated amount of GHG emissions.

services, and below-grade stations, as this would further facilitate improvement in the accuracy of reported emissions under Subpart W. In particular, we recommend that the Agency allow companies/utilities to use an emission factor developed via an LDC's survey of above-ground T-Ds to estimate emissions from below-grade stations. While emission factors based on direct measurement and top-down efforts like AMLD campaigns may be feasible for larger gas utilities, such a method may be beyond the resources of smaller gas utilities—especially those that are operated by municipalities. Allowing a utility to use its above-ground T-D emission factor for below-grade T-Ds and both above- and below-grade M&Rs is appropriate because leak rates are very low for both categories of stations.

Further, in the event of a leak, where the utility follows detection with repair, the utility should not be required to assume that the leak continued for the entire year or until the next above-ground T-D survey. Instead, the completion date of the leak repair should be used as the end point for the leak—because it *is* the end point for the leak. This approach is not only more accurate, but it also leverages data that LDCs are already required to collect regarding leak detections and repairs, and incentivizes emission reductions via speedy leak repairs.

C. The Associations agree with EPA's assessment of the current state of top-down data and support the Agency's proposal to not require its use in Subpart W reporting.

As noted in Section II.A.1. of these comments, the Associations recognize both the promise and potential drawbacks of using top-down data to estimate methane emissions. EPA recognizes this as well, and as such is not proposing to *require* the use of top-down approaches for Subpart W reporting but is instead open to the use of top-down methods "to supplement the other requirements for periodic measurement and calculation of annual emissions."[33] In support of EPA's proposed approach, the Associations offer the following information for the Agency's consideration.

Some stakeholders allege that current bottom-up methods significantly underestimate fugitive methane emissions from natural gas pipeline facilities as compared to top-down methods; however, sound science shows that this is not the case. Both a landmark, peer-reviewed study and a National Academy of Sciences ("NAS") report explain that the perceived gap between top-down studies and inventories that are based on bottom-up measurements and emission factors is largely explained by the temporal and spatial differences in the two types of measurements. The study and the NAS report each concluded that the top-down and bottom-up approaches can be reconciled when both are conducted in the same time and place.

The Associations would like to highlight the 2015 Fayetteville Basin Methane Reconciliation Study,[34] which found that the difference between the top-down and bottom-up methane measurements could be largely explained by the different time and spatial scale of the measurements. The Fayetteville Study generated eight peer-reviewed scientific journal articles, culminating in a 2018 capstone paper titled "Temporal Variability Largely Explains Difference in Top-Down and Bottom-Up Estimates of Methane Emissions from a Natural Gas Production

[33] Proposed Rule, 88 Fed. Reg. at 50,291.

[34] Colorado State University: Energy Institute, *Fayetteville Study: Basin Reconciliation*, https://energy.colostate.edu/metec/fayetteville-study-basin-reconciliation/ (last visited Oct. 2, 2023). The website contains a summary paper, a series of methodology papers, and an explanatory video.

Region."[35] The paper demonstrated how the Fayetteville Study successfully provided the first temporally and spatially aligned top-down and bottom-up methane emissions estimates for a shale gas production basin in the United States. The study reconciled top-down aircraft measurements with facility- and equipment-level bottom-up measurements on basin, site, and component scales by aligning them in the same time frame and place. The Fayetteville Study website contains a summary paper that describes, in layman's terms, the study's key findings, insights, and implications for industry practice and future studies.[36]

The Associations also wish to highlight a 2018 NAS consensus report, which recommended that other studies seeking to reconcile top-down and bottom-up methane measurements use the methodology from the Fayetteville Study.[37] The NAS report specifically recommended that researchers work with facility operators to obtain site access for bottom-up facility and equipment measurements, and then align those measurements in time and space with top-down measurements. Notably, one of the reasons that the Associations support EPA's proposal to not rely on the Weller Study—as discussed above in Section II.B.1. of these comments—is that it did not evaluate top-down measurements together with bottom-up facility measurements paired in time and space.

For further detail on this issue, the Associations invite EPA to review their recent comments on the Pipeline and Hazardous Materials Safety Administration's ("PHMSA") proposed rule titled "Pipeline Safety: Gas Pipeline Leak Detection and Repair," which were filed together with INGAA and several other oil and natural gas industry associations.[38]

D. While the Associations support EPA's proposal to allow the use of direct measurement to quantify emissions from equipment leak components, several additional improvements would increase the accuracy of distribution segment emissions estimates.

EPA is proposing to revise the method of quantifying emissions via equipment leak surveys under Subpart W. The current calculation method uses (1) the count of leakers detected using a leak detection method listed in 40 C.F.R. § 98.234(a), (2) the Subpart W leaker emission factors for specific component types and leak definitions, and (3) an estimate of the total time that the surveyed components were assumed to be leaking and operational. In the 2022 Proposal, EPA proposed to provide separate leaker factors for leaks detected using optical gas imaging ("OGI") vs. other leak detection methods. For downstream industry segments, the proposed OGI emission factors were estimated using an "OGI enhancement factor," which was estimated as the ratio between the OGI emission factors and the Method 21 emission factors that EPA proposed for the upstream industry segments. The Proposed Rule would maintain the previously proposed

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[35] Timothy L. Vaughn et al., *Temporal Variability Largely Explains Top-Down/Bottom-Up Difference in Methane Emission Estimates from a Natural Gas Production Region*, 115 PROC. NATL. ACAD. SCI. 11712–17 (Oct. 29, 2018), https://www.pnas.org/doi/10.1073/pnas.1805687115.

[36] Garvin Heath, National Renewable Energy Laboratory, *Basin Methane Reconciliation Study: Overview of Results* (Oct. 25, 2018), https://energy.colostate.edu/wp-content/uploads/sites/28/2021/03/BasinMethaneOverview.pdf.

[37] National Academies of Sciences, Engineering, and Medicine, *Improving Characterization of Anthropogenic Methane Emissions in the United States* (Mar. 27, 2018), https://nap.nationalacademies.org/catalog/24987/improving-characterization-of-anthropogenic-methane-emissions-in-the-united-states.

[38] AGA and APGA et al. Comments on Pipeline Safety: Gas Pipeline Leak Detection and Repair (Aug. 16, 2023), https://www.regulations.gov/comment/PHMSA-2021-0039-26350.

approach of having separate emission factors for OGI-detected leaks but would update the proposed downstream emission factors based on a revised "OGI enhancement factor" that uses more recent study data.[39] EPA also is proposing to apply a factor to account for undetected leaks for facilities that use the leaker calculation methods. The Associations oppose both of these proposed adjustment factors.

The Proposed Rule also would provide two alternatives to using the default leaker emission factors—either of which would be available to Subpart W reporters. One option would be to quantify emissions from equipment leak components by performing direct measurement of equipment leaks and calculating emissions using those measurement results. Another option would be for facilities to use their leak survey results to develop component-level emission factors, which would be based on a minimum of 50 individual measurements. The Associations appreciate that LDCs would be able to use direct measurements to either calculate or estimate their component-level emissions; however, the proposed criteria for developing site-specific emission factors are impracticable, making it unlikely that this option can realistically be put into practice for natural gas distribution facilities.

1. **The proposed "OGI enhancement factor" and "k factor" should not apply to LDCs because they are based on upstream segment data and are therefore unrepresentative of distribution segment emissions.**

According to EPA, OGI finds "fewer and larger leaks" at upstream facilities than Method 21 does and "the leaker emission factors for other industry segments that are based on measurements of Method 21-identified leaks may similarly underestimate the emissions from leaking equipment when OGI (or other alternative methods besides Method 21) are used to detect the leaks."[40] Consistent with the 2022 Proposal, EPA is once again proposing larger leaker emission factors for OGI screening than for Method 21 screening, which the Agency proposes to effectuate via an "OGI enhancement factor" applied to the leaker emission factors for each downstream segment. EPA is similarly using upstream study data to justify a proposed "undetected leak factor," which the Agency calls the "k factor," that purports to reflect the inherent variability in leak screening methods and survey conditions that can result in undetected, unreported leaks.[41] The k factor would be applied to the emissions quantified by leaker calculation methods. For both factors, EPA is making a baseless assumption that upstream data is equally applicable downstream. The Associations oppose the proposed application of the OGI enhancement factor and the k factor to distribution segment leak emissions estimates for the same reasons that INGAA provides with

[39] According to EPA, the Zimmerle et al. (2020) and Pasci et al. (2019) studies use more recent data and a larger dataset than what was used for the current emission factors. *See* Proposed Rule, 88 Fed. Reg. at 50,343. The Associations concur in INGAA's detailed analysis of why these studies should not be used to estimate downstream emissions.
[40] *Id.* at 50,344.
[41] "Based on the Pacsi *et al.* (2019) study data, OGI observes 80 percent of emissions from measured leaks, Method 21 at a leak definition of 10,000 ppm observes 65 percent of emissions from measured leaks, and Method 21 at leak definition of 500 ppm observes 79 percent of emissions from measured leaks. . . . [V]ery few onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities use infrared laser beam illuminated instruments or acoustic leak detection devices to conduct equipment leak surveys, so there are no data available to develop a method-specific adjustment factor, k, for these detection methods. Based on our understanding of these alternative methods, we expect that their leak detection thresholds would be most similar to OGI, so that the average emissions per leak identified by these alternative methods would be similar to the emissions estimated using OGI." *Id.* at 50,345.

regard to the transmission and storage segments. The Associations urge EPA not to add either adjustment factor to the leaker emission factors for LDC equipment.

2. The Associations support EPA's proposal to allow emissions to be quantified using direct measurement results from leak surveys.

We are pleased that the Agency is proposing an option for facilities in the natural gas value chain to calculate emissions based on the results of direct measurement of equipment leaks, as this will allow for more accurate reporting. The Associations have long advocated for such a direct measurement option, which would employ methods such as calibrated bagging or a high-volume sampler to detect leaks at above-grade T-D stations. Under this proposed option, leak quantification would be via a "complete leak detection survey," *i.e.*, facilities using this option could not use leaker emission factors for some leaks and direct measurement for others.

In recognition of the fact that a "facility" in the natural gas distribution segment is not limited to the traditional notion of a "facility" within a fence line,[42] but is instead much more expansive and may involve as many as hundreds or even thousands of T-Ds across a single state, EPA is proposing to allow LDCs to conduct leak detection surveys across multiple years[43]—provided that each year's survey monitors approximately the same number of stations each year and the entire cycle of surveying all T-Ds does not exceed five years.[44] For LDCs that use the multi-year survey option, EPA is proposing that all of the T-Ds surveyed during a calendar year would be considered a "complete leak detection survey" for the purpose of being able to use the direct measurement option.[45] This provision is important to the feasibility of the direct measurement option because using a high-volume sampler or calibrated bag is time consuming, and there are numerous components to be measured, so most gas utilities would need to spread their leak surveys over more than one year.

Recognizing that use of the direct measurement option requires a "complete leak detection survey," which for LDCs may take up to five years to complete, the Associations request that companies/utilities be allowed to continue using their previous T-D emission factors for any stations that have not yet been subject to direct measurements until such time as all of that LDC's stations have gone through one full cycle of surveying. Once the full cycle of measuring all T-Ds has been completed, the previous emission factors would no longer be used.

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[42] The current Subpart W definition of a "facility" with respect to natural gas distribution is: "the collection of all distribution pipelines and metering-regulating stations that are operated by a Local Distribution Company (LDC) within a single state that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system." 40 C.F.R. § 98.238. EPA is not proposing to change the current definition; however, it is proposing to remove the "inadvertent identical duplicative definition" from the regulatory text. *See* Table 4 to Proposed Rule, 88 Fed. Reg. at 50,364 (listing proposed technical corrections).

[43] The Associations have identified an apparent typographical error in the proposed regulatory text: proposed 40 C.F.R. § 98.233(q)(3)(viii)(B) contains a cross-reference to "paragraph (q)(3)(vii)(A)," however, neither the current nor the proposed text contain the referenced citation.

[44] *See* Proposed 40 C.F.R. § 98.233(q)(1)(vii) shown on 88 Fed. Reg. at 50,405.

[45] *See* Proposed 40 C.F.R. § 98.233(q)(1)(vi)(G) shown on 88 Fed. Reg. at 50,404–05.

3. **The Associations support the concept of site-specific leaker emission factors; however, the proposed criteria would effectively prevent LDCs from using this option.**

EPA is proposing to allow facilities to use direct measurement from leak surveys to develop component-level emission factors based on site-specific leak measurement data. The Proposed Rule would require Subpart W reporters to compile at least 50 individual measurements of natural gas flow rate for a specific component type and leak detection method (*e.g.*, gas service valves detected by OGI) before a site-specific emission factor may be used for that component type at the reporter's facility.[46] To generate the site-specific emission factor, the reporter would add the 50 (or more) volumetric measurements and divide the sum by the total number of leak measurements for that component type and leak detection method combination, resulting in an emission factor in units of standard cubic feet ("scf") per hour-component.

As noted throughout these comments, the Associations conceptually support the option to develop site-specific emission factors. We also support the proposed option to allow reporters to use a combination of default leaker factors for some component types and site-specific leaker factors for other component types, given that component types will reach the minimum measurement threshold at different rates. However, this emission factor option would benefit from additional flexibilities—specifically with regard to the 50-measurement threshold. It could take some LDCs many years or even *decades* to obtain 50 individual measurements from a particular component type, if they ever do, because of how infrequently distribution components leak relative to those in other industry segments. The 50-measurement requirement would thus prevent many LDCs from being able to use site-specific emission factors. EPA could address this issue in several different ways, including by developing sub-classes of components that may use site-specific emission factors after fewer individual measurements and/or by allowing LDCs to develop company/utility-wide emission factors—or even collaboratively developed emission factors, as discussed in Section II.A.2. of these comments. Particularly with regard to collaborative emission factors, LDCs would be able to reach the 50-measurement minimum within a reasonable time frame if they were allowed to develop emission factors together. Without more flexibility, the site-specific, component-level emission factor option is not viable for the distribution segment.

E. **The Associations request that EPA incorporate additional flexibilities and clarifications into the Subpart W requirements for combustion equipment emissions.**

The GHGRP currently requires facilities in certain segments, including the distribution segment, to report combustion emissions under Subpart W. With regard to those segments, EPA is proposing to revise the methodologies for determining combustion emissions from reciprocating internal combustion engines ("RICE") and gas turbines ("GT") to better account for combustion slip.[47] The Associations ask EPA to make the combustion slip quantification more flexible and, as a general matter, to provide further clarification on the applicability of 40 C.F.R. § 98.233(z).

For distribution sector RICE and GT that meet the criteria in current 40 C.F.R. § 98.233(z)(1) (*e.g.*, units that combust one or more of the fuels listed in Table C-1 to Part 98),

[46] Proposed Rule, 88 Fed. Reg. at 50,346–47.

[47] *Id.* at 50,356–59. Combustion slip (also called "methane slip") occurs when unburned CH_4 is entrained in the exhaust of natural gas-fired engines. *See id.*

EPA is proposing to allow reporters to select from three options to quantify emissions from combustion slip: (1) a CH_4 emission factor based on direct measurement via a performance test, (2) a CH_4 emission factor based on original equipment manufacturer ("OEM") data, or (3) a default CH_4 emission factor. To use a performance test emission factor, a facility would have to conduct a performance test pursuant to the criteria in proposed 40 C.F.R. § 98.234(i).[48] Facilities that use the default would select the appropriate emission factor by equipment type (2-stroke or 4-stroke lean-burn, 4-stroke rich-burn, or GT) provided in new Table W-7.[49] For distribution sector RICE and GT that meet the criteria in current 40 C.F.R. § 98.233(z)(2) (*e.g.*, units that combust field gas or process vent gas), reporters would be required to use a default equipment-specific combustion efficiency that would account for methane slip and be combined with fuel composition to calculate emissions.[50]

With regard to the proposed combustion slip emissions quantification methods, the Associations ask EPA to consider whether these procedures can benefit from additional flexibility. For example, Association members note that OEM data may not include methane emissions, whereas third-party service providers that work with a facility's RICE or GTs may have the requisite methane data for developing emission factors.[51] We also request that alternate forms of performance testing that are already required under other regulatory programs, such as permit conditions for RICE-driven compressors that are not EPA certified, be deemed allowable bases for developing a CH_4 emission factor. These flexibilities would reduce the administrative burden on covered facilities while maintaining reporting accuracy.

More generally, the Associations request that EPA provide more clarity regarding which combustion equipment emissions are subject to Subpart W reporting. For example, it is unclear from Subpart W whether emergency generator emissions are reportable. Such emissions are explicitly exempt from Subpart C reporting[52] and the Associations believe Subpart W should contain the same clearly phrased exemption. Subpart W is similarly unclear about whether emissions flared from RICE or GTs are reportable as combustion emissions. While Subpart W as a whole could benefit from reorganization to make its requirements clearer to regulated entities, the Subpart W reporting obligations for combustion emissions are particularly unclear.

[48] The Associations have identified an apparent typographical error in the proposed regulatory text: proposed 40 C.F.R. § 98.234(i) references "paragraphs (j)(1) through (3) of this section," but there is no paragraph (j) in that section. We believe the text should refer to "paragraphs (i)(1) through (3) of this section."

[49] This refers to a new table that would be numbered W-7 if the Proposed Rule is finalized. EPA is proposing to modify and renumber *existing* Table W-7 as Table W-5.

[50] EPA is proposing the following default combustion efficiencies by equipment type: 2-stroke lean-burn RICE (0.953), 4-stroke lean-burn RICE (0.962), 4-stroke rich-burn RICE (0.997), GTs (0.999). *See* Proposed Rule, 88 Fed. Reg. at 50,411 (equations W-39A and W-39B).

[51] The Associations concur in INGAA's comments on the issue of OEM and service-provider emission factors.

[52] *See* 40 C.F.R. § 98.30(b)(2) ("This source category does not include . . . [e]mergency generators and emergency equipment, as defined in § 98.6.").

F. **Subpart W reporters should have the option of using measured data to calculate their emissions or improve estimated emissions from crankcase venting.**

EPA proposes to require reporting of CH_4 emissions from crankcase ventilation from RICE and GTs used in the distribution segment,[53] among others.[54] The Proposed Rule describes crankcase ventilation as the process of venting or removing blow-by from the void spaces of an internal combustion engine outside of the combustion cylinders to prevent excessive pressure build-up within the engine, but not including ingestive systems that vent blow-by into the engine where it is returned to the combustion process. EPA is proposing to provide a component-level average emission factor approach for estimating emissions from crankcase ventilation based on the number of crankcase vents in the facility.

The Associations request that EPA add the option for reporters to develop site-specific emission factors based on direct measurements for crankcase venting. The proposed CH_4 emission factor for crankcase ventilation is 2.28 scf/hour/source, which was developed based on data measured at gas processing plants, gathering compressor stations, and well sites—*i.e.*, facilities that are upstream from LDCs. For distribution segment facilities that wish to devote time and resources to developing their own emission factors for crankcase venting, this would allow for a more accurate reflection of methane emissions for this source type.

In addition, the Associations concur in INGAA's comments on the applicability of crankcase venting requirements—*i.e.*, crankcases and vents are associated with RICE, not GTs, therefore GTs should be removed from proposed 40 C.F.R. § 98.233(ee) and § 98.236(ee).

G. **As proposed, EPA's requirements for reporting blowdown stack emissions from dig-ins are unworkable with respect to the distribution segment.**

EPA is proposing to add distribution to the industry segments that are required to report blowdown vent stack GHG emissions.[55] For other industry segments, Subpart W currently requires reporting of blowdowns using either flow meter measurements or unique physical volume calculations by equipment or event types. EPA is essentially proposing to drop the distribution segment into the existing blowdown requirements at 40 C.F.R. § 98.233(i), which is akin to trying to fit a square peg into a round hole. Both the applicability determination and manner of calculating blowdown emissions depend on calculating unique physical volume between isolation valves; however, isolation valves are uncommon in the distribution segment, so it is not possible to derive a unique physical volume. EPA must revise its proposed language for § 98.233(i) so that it includes applicability criteria and calculation methodology that is actually workable for estimating blowdown emissions due to dig-ins (*i.e.*, excavation damage) at distribution pipelines.[56]

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[53] Proposed Rule, 88 Fed. Reg. at 50,308–09.

[54] In addition to their distribution operations, many AGA member companies also operate transmission compression, underground storage, and/or LNG storage facilities as part of the gas utility system regulated by their state's utility commission. Each of those other segments also would be affected by the proposed addition of crankcase venting as a reportable emission source under Subpart W.

[55] Proposed Rule, 88 Fed. Reg. at 50,324–25.

[56] The Associations' comment on applicability is specific to the "unique physical volume" threshold. We support EPA's proposal to retain the existing reporting exemptions for "blowdown vent stack emissions from depressurizing

The current blowdown emissions applicability language, which EPA does not propose to change, states that "[e]quipment with a unique physical volume of less than 50 cubic feet" is not subject to the blowdown emission reporting requirements and that facilities must "calculate each unique physical volume . . . between isolation valves, in cubic feet, by using engineering estimates based on best available data."[57] The lack of isolation valves means that LDCs have no way to calculate unique physical volume, so there is no way to determine which dig-ins have reportable blowdown emissions under Subpart W. It would be extremely burdensome for LDCs to have to report *all* blowdown vent stack emissions due to dig-ins—which are generally caused by third-party activities, not by LDCs themselves. EPA has previously recognized that including "tiny blowdown sources would be a substantial burden for little contribution to emissions," which was not the Agency's intent in establishing the original blowdown vent stack reporting requirements under Subpart W.[58] Distribution line dig-in emissions can typically be mitigated quickly by pinching off the pipeline until a full repair can be completed, and the lower pressure in distribution lines also reduces emissions, therefore most dig-ins would be the type of "tiny blowdown sources" that EPA did not intend to include in Subpart W. EPA should establish a separate threshold for distribution segment dig-ins that appropriately excludes these types of minor blowdown emissions.

Without a unique physical volume, blowdown emissions calculations W-14A and W-14B are each missing required inputs, so the calculations cannot work. To facilitate the estimation of blowdown emissions for distribution segment dig-ins that are reportable under Subpart W, EPA should provide an engineering calculation that relies on pipeline diameter, pressure, temperature, and event duration. Alternatively, EPA could establish dig-ins as a separate emission source under Subpart W; however, the Agency would have to do this via a supplemental rulemaking to give LDCs and other stakeholders sufficient notice and opportunity to comment. Yet another option would be to exclude distribution dig-in emissions altogether in light of how minimal they are. In any event, EPA's current proposal for addressing distribution dig-in emissions under Subpart W is not viable as written.

H. If EPA adds pneumatic device venting as a reportable source for the distribution segment, the Agency should provide more flexibility for the manner of determining emissions from LDCs' pneumatic devices.

EPA is proposing to add distribution to those industry segments required to report their GHG emissions vented from pneumatic devices, and also proposes to revise the calculation methods for all segments that are subject to this requirement.[59] Subpart W currently requires the calculation of GHG emissions from pneumatic device venting using default population emission factors multiplied by the number of devices and the average time those devices are in gas service. Under the Proposed Rule, emissions from pneumatic devices would be calculated based on direct measurements and leak screening. The existing default population emission factors for intermittent bleed natural gas pneumatic devices would no longer be applicable and the default population emission factors for continuous bleed natural gas pneumatic devices would only be

to a flare, over-pressure relief, operating pressure control venting, blowdown of non-GHG gases, and desiccant dehydrator blowdown venting before reloading." 40 C.F.R. § 98.233(i).

[57] *Id.*

[58] *See* EPA Memorandum: Equipment Threshold for Blowdowns (Nov. 1, 2010), https://www.regulations.gov/document/EPA-HQ-OAR-2009-0923-3581.

[59] Proposed Rule, 88 Fed. Reg. at 50,310–16.

applicable for the leak screening method. EPA is proposing three new calculation methods: Calculation Method 1 for pneumatic devices that use a flow monitoring device; Calculation Method 2 for pneumatic devices that do not use a flow meter, which includes a proposed facility-specific emission factor for facilities that conduct vent measurements over several years; and Calculation Method 3 for facilities that monitor for malfunctioning intermittent bleed pneumatic devices (analogous to a "leaker factor").

Pneumatic device venting is a notable source of GHG emissions in the upstream segments of the natural gas value chain but is a much lesser contributor further downstream—particularly in the distribution segment. EPA should consider whether requiring pneumatic device reporting is worthwhile for the distribution segment and, if it is, the Agency should provide a less burdensome manner of estimating those emissions. LDCs should not be required to spend significant time and resources to conduct direct measurements of such low-emitting devices.

If pneumatic device reporting is finalized for the distribution segment, then the Associations request that EPA offer additional methods of meeting Subpart W reporting obligations. Some options to consider are: (1) BAMM reporting, (2) a more streamlined manner of developing facility-specific emission factors, and/or (3) a "sunsetting" of reporting obligations after a set period of time. As to sunsetting, the Associations believe that if LDCs can demonstrate that their pneumatic device emissions are relatively trivial (*e.g.*, not exceeding a specified percentage of overall segment or sector emissions), then facilities should not be required to conduct measurements each year for Subpart W purposes. EPA should consider sunsetting pneumatic device reporting obligations for LDCs after a specified number of years or a large enough data set is accumulated such that a durable facility-specific emission factor can be established. Alternatively, for segments that have relatively low pneumatic device emissions—such as the natural gas distribution, transmission, and storage segments[60]—EPA could maintain the current default emission factors for calculating reportable pneumatic device emissions.

I. The proposed threshold for reporting "other large release events" is too low and the presumptive release duration is too long for the stated purpose of capturing super-emitter event emissions.

EPA is proposing to add "other large release events" as a new emissions source subject to reporting under Subpart W for all segments of the oil and natural gas industry.[61] The Agency intends for "other large release events" to cover emissions from abnormal emission events or "super-emitters," such as well blowouts, well releases, releases from equipment rupture, fire, or explosions. As proposed, "other large release events" would include planned releases, such as those associated with maintenance activities, for which there are not already emission calculation procedures in Subpart W, or releases from equipment for which the existing Subpart W calculation methodologies would significantly underestimate the episodic nature of those emissions. Under the Proposed Rule, the threshold for an "other large release event" is either a release of at least 250 mtCO_2e per event or a CH_4 emission rate of at least 100 kg/hour at any point during the event. These thresholds are much lower than what is typically considered a "super-emitter" event, including the Aliso Canyon (100,000 mt CH_4) and Ohio well blowout (40,000 to 60,000 mt CH_4)

[60] INGAA's comments on the Proposed Rule contain further detail on pneumatic device emissions in the natural gas transmission and storage segments.
[61] Proposed Rule, 88 Fed. Reg. at 50,296–301.

examples that EPA provides in the preamble to the Proposed Rule.[62] EPA should revise the thresholds to more closely align with the underlying purpose of adding "other large release events" as an emissions source under Subpart W. The Associations believe that the PHMSA definition of "incident" as an "[u]nintentional estimated gas loss of three million cubic feet or more"[63] is a more reasonable threshold; however, we note that this is still orders of magnitude lower than EPA's super-emitter examples.

The Associations support the flexibility that EPA proposes for the manner of calculating emissions of "other large release events," which is to use measurement data if it is available, or a combination of engineering estimates, process knowledge, and best available data to estimate both the amount and composition of released gas.[64] It is reasonable and sound to allow the estimates to be tailored to the type of release at issue and rely on the expertise of the facility staff, particularly given how broad the "other large release events" category is. However, the Associations believe that the proposed presumptive release duration of 182 days (*i.e.*, six months) prior to the documented end of a release—a duration that would be used in the absence of more definitive information on the start time—is excessive. Given that most large releases are intermittent and typically only several hours or several days in duration,[65] EPA should consider a presumptive duration that is closer to the typical event length, as that would result in a more representative emissions calculation to be used in charging the Section 136(c) methane fee.

J. The Associations oppose the proposed inclusion of the natural gas distribution segment in new Subpart B for energy consumption reporting because it exceeds EPA's Clean Air Act authority while providing little informational benefit.

The 2023 Supplemental Proposal would create a new Subpart B for reporting the quantity of metered electricity and thermal energy purchased by a facility, which would apply to all facilities that report their direct emissions under other GHGRP subparts.[66] The Proposed Rule would add language "to clarify the intent for subpart W reporters to also report under subpart B."[67] The Associations reiterate our opposition to EPA's proposal to require natural gas distribution facilities to report their energy consumption under the GHGRP.[68]

EPA does not have authority under the GHGRP to collect broad energy consumption data and, in any event, has not shown how such data would be relevant to establishing emission standards and limitations. Congress has not authorized EPA to collect data for unspecified purposes untethered from its regulatory authority and, even if the Agency had authority to collect such energy consumption data, it is not clear what regulatory benefit EPA would obtain in exchange for imposing this broad reporting burden on facilities. If, in spite of the lack of authority to do so,

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[62] *Id.* at 50,296.
[63] 49 C.F.R. § 191.3.
[64] Proposed Rule, 88 Fed. Reg. at 50,297.
[65] *See id.*; *see also* Greenhouse Gas Reporting Rule: Technical Support for Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule; Proposed Rule – Petroleum and Natural Gas Systems at 27.
[66] *See* 2023 Supplemental Proposal, 88 Fed. Reg. 32,852 (May 22, 2023).
[67] Proposed Rule, 88 Fed. Reg. at 50,296.
[68] More extensive discussion on these points is available in the Associations' comments on the 2023 Supplemental Proposal. *See* AGA and APGA Comments on 2023 Supplemental Proposal (July 21, 2023), https://www.regulations.gov/comment/EPA-HQ-OAR-2019-0424-0318.

EPA finalizes proposed new Subpart B, it should exempt natural gas distribution facilities from this reporting requirement. Imposing electricity reporting on the distribution segment would entail undue complexity, as it requires gathering the relevant portions of multiple small bills from multiple providers, yet it would yield minimal useful information because of the minor amount of electricity consumed by the distribution segment. There is little indication that this energy consumption information would provide any benefit to EPA or the public.

K. The Associations support the removal of certain throughput reporting elements from Subpart W that are duplicative of Subpart NN.

According to the Proposed Rule, there are no LDCs that report under Subpart W that do not also report under Subpart NN of the GHGRP.[69] EPA has determined that Subpart W contains several throughput reporting requirements that are duplicative of data elements in Subpart NN. To eliminate reporting redundancies and reduce burden—and because Subpart NN has been in effect for LDCs longer than Subpart W's throughput requirements—EPA is proposing to remove certain data elements from Subpart W and retain the analogous requirements in Subpart NN. Specifically, the Proposed Rule would eliminate the Subpart W requirement for LDCs to report the quantities of natural gas (1) received at all custody transfer stations, (2) withdrawn from in-system storage, (3) added to in-system storage, and (4) delivered to end users. EPA also is proposing to remove the requirement to report the volume of natural gas used for operational purposes and the volume of stolen natural gas, as EPA has not used these elements for its analyses of Subpart W data. The Associations support the proposed removal of these Subpart W throughput reporting requirements for the distribution segment for the reasons set out in the preamble to the Proposed Rule.[70]

L. The Associations request that EPA provide a reasonable time—at least one year after publication—before facilities must comply with the new Subpart W requirements.

The IRA requires EPA to finalize the Subpart W revisions by August 16, 2024; however, it does not specify a particular effective date or compliance deadline for these revisions.[71] EPA is proposing to make the Subpart W amendments effective on January 1, 2025, with reporters implementing the resulting changes beginning with reports prepared for Reporting Year 2025 and submitted by March 31, 2026.[72] This is an aggressive timeline given the extent of processes that would have to be changed by LDCs in order to comply with the new direct measurement requirements and calculation methods. The Associations urge EPA to establish either an effective date or a compliance deadline that is no shorter than one year after publication of the final rule.

Emission data collection processes at natural gas distribution systems are embedded in larger operations and maintenance procedures. Those procedures can only be modified within often rigorous Management of Change ("MOC") programs, which are deliberately designed to require significant subject matter input and approval by employees or departments impacted by a given change. A requirement to immediately modify the data collection procedures after the new requirements are finalized (followed by training for employees implementing the new procedures) is far from a reasonable expectation. Additionally, given the technological elements of the

[69] Proposed Rule, 88 Fed. Reg. at 50,362.
[70] *See id.* at 50,361–63.
[71] *See* 42 U.S.C. § 7436(h).
[72] Proposed Rule, 88 Fed. Reg. at 50,364–65.

Proposed Rule, LDCs will need to work closely with contractors to implement permanent measuring equipment and/or significantly change their monitoring programs and related IT systems. Companies/utilities across the country will all be seeking new or modified measuring equipment at the same time as one another, which could cause both labor shortages and supply-chain issues. It is not reasonable to expect reporting entities to be able to evaluate the new requirements and establish systems to accurately collect the required data elements within such a short period (roughly four-and-a-half months, as currently proposed). Further, in certain jurisdictions, public utility commission approval may be needed to deploy certain leak detection technologies.[73] The Associations ask EPA to provide at least one year for compliance with the new Subpart W requirements. Given that the reporting year aligns with the calendar year, this means that compliance with the Subpart W revisions would not be required until January 1 of the year that is at least 12 months after publication of the final rule (*e.g.*, assuming the final rule is timely published on August 16, 2024, the compliance deadline would be no earlier than January 1, 2026).

EPA has chosen to implement the Section 136(c) methane fee through a separate rulemaking from the Subpart W revisions; EPA is targeting October 2023 for issuing a proposed rule and May 2024 for issuing a final rule.[74] Because the rulemaking process and schedule of these two regulations have been decoupled from one another, EPA clearly recognizes that it is not necessary to tie the effective date of the Subpart W revisions to the statutory start date of the methane fee program.[75] This is particularly true with regard to Subpart W compliance for the distribution segment, which is not subject to the methane fee.[76] Therefore, if EPA determines that it will not extend the proposed effective date for the entire source category, it could still provide a longer compliance date with respect to natural gas distribution facilities.

The compliance deadline for the Subpart W revisions also should align with deadlines for forthcoming regulations—two in particular—that are expected to require similar, yet not identical, methane emission monitoring requirements for the natural gas industry. First, PHMSA recently closed a public comment period on its proposed rule titled "Pipeline Safety: Gas Pipeline Leak Detection and Repair."[77] The PHMSA proposal would regulate methane emissions from new and existing gas transmission pipelines, distribution pipelines, underground natural gas storage facilities, LNG facilities, and certain gas gathering pipelines. PHMSA has proposed new leakage survey and patrolling requirements; performance standards for advanced leak detection; leak

[73] For example, in New York, leak detection instruments must be approved by the Department of Public Service ("DPS"). *See* 16 NYCRR Part 255.3; *see also* NY DPS, Gas Leak Detection Instruments and Devices, https://dps.ny.gov/gas-leak-detection-instruments-and-devices (last accessed Sept. 29, 2023).

[74] *See* Spring 2023 Unified Agenda, RIN 2060-AW02: Methane Emissions and Waste Reduction Incentive Program for Petroleum and Natural Gas Systems, https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202304&RIN=2060-AW02. The Associations believe that this separate rulemaking process makes sense, as the IRA directive to ensure that methane reporting is accurate and based on empirical data is broader than just the methane fee. *See* 42 U.S.C. § 7436(h) (stating that EPA "shall revise [Subpart W] to ensure the reporting under such subpart, . . . [is] based on empirical data . . . [and] accurately reflect[s] the total methane emissions and waste emissions from the applicable facilities . . . ."). For the distribution segment, which is not statutorily subject to the methane fee, the separate rulemaking reaffirms Congress's intent for all Subpart W facilities to be able to use empirical data in their reporting.

[75] The projected timing of the methane fee regulatory program is not even tied to the start of the statutory program: Section 136(g) of the Clean Air Act states that the methane fee "shall be imposed and collected beginning with respect to emissions reported for calendar year 2024 and for each year thereafter," 42 U.S.C. § 7436(g), yet EPA is targeting mid-2024 for issuing the final methane fee rule.

[76] *Id.* § 7436(f) (distribution not identified as a segment subject to the methane fee).

[77] 88 Fed. Reg. 31,890 (May 18, 2023) (comments accepted through August 18, 2023).

grading and repair criteria with mandatory repair timelines; requirements for mitigation of emissions from blowdowns; pressure relief device design, configuration, and maintenance requirements; clarified requirements for investigating failures; and expanded reporting requirements for all gas pipeline facilities within PHMSA's jurisdiction. PHMSA has not yet indicated when it aims to finalize its proposal.

Second, by the end of 2023, EPA is expected to issue a final rule on new source performance standards ("NSPS") and emission guidelines ("EGs") for methane emissions from the oil and natural gas sector under 40 C.F.R. Part 60, Subparts OOOOb and OOOOc. In their capacity as LDCs, Association members do not expect to be covered by this forthcoming final rule.[78] However, many AGA member companies also operate equipment within industry segments other than distribution, including onshore natural gas transmission compression, both intrastate and interstate transmission pipelines, underground natural gas storage, and LNG storage. Thus, many natural gas facilities will be subject to as-yet undetermined requirements for methane monitoring, emissions calculations, and reporting—meaning that they will have to develop and deploy new or modified systems, equipment, and procedures to comply with the new NSPS and EG requirements, the PHMSA rule, *and* the new Subpart W requirements. It would be much more efficient, cost-effective, reasonable, and technically effective for companies to be able to make the requisite changes all at once instead of doing so in a manner that is both rushed and piecemeal.

M. The Associations support INGAA's comments regarding EPA's proposals for natural gas transmission, storage, and LNG operations.

As noted above, many of AGA's members operate intrastate natural gas transmission pipelines, transmission compression, underground storage, and/or LNG storage facilities as part of the gas utility system regulated by their state's utility commission. These intrastate facilities are subject to the same Subpart W reporting regulations as the interstate counterparts operated by INGAA's members. And, although APGA members generally do not operate such facilities in their smaller gas utility systems, they are concerned about the costs that their upstream interstate pipeline suppliers could face from proposed changes to Subpart W—whether via inflated methane fee charges resulting from insufficiently accurate measurement methods or unnecessarily excessive new reporting burdens. Accordingly, the Associations support INGAA's comments on EPA's proposed revisions to Subpart W for natural gas transmission, storage, and LNG operations as applied to both interstate and intrastate gas utility facilities.

III. CONCLUSION

The Associations offer the foregoing comments to assist EPA in improving the accuracy of Subpart W reporting and carrying out the Agency's mandate under Section 136 of the Clean Air Act. We appreciate the Agency's consideration of our input and are available as a resource for EPA staff throughout the development of this rulemaking. If you have any questions, please

[78] For facilities inside and including the LDC custody transfer station, EPA has proposed to maintain the methane NSPS exemption, which has been in place since the methane NSPS was first established for the oil and natural gas source category. *See* 86 Fed. Reg. 63,110 (Nov. 15, 2021) (proposed rule); 87 Fed. Reg. 74,702 (Dec. 6, 2022) (supplemental proposed rule).

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