American Gas Association

American Public Gas Association

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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

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[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

[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 CH_4 sources, but this capability could be added by analyzing both CH_4 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.

Respectfully Submitted,

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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

[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:

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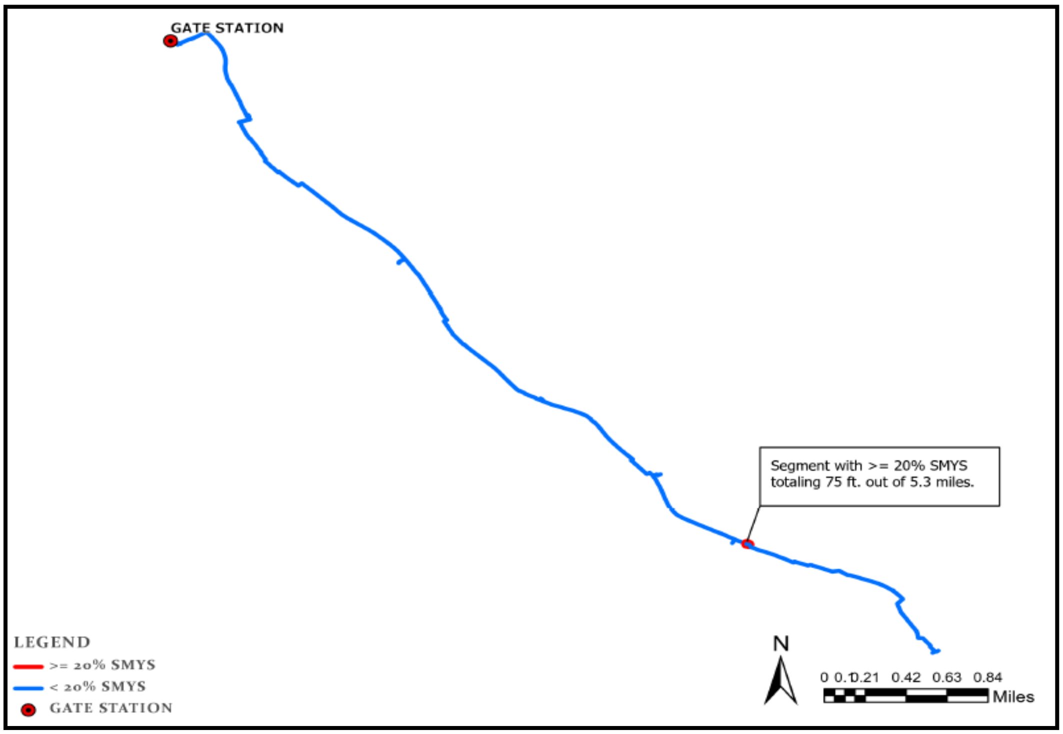
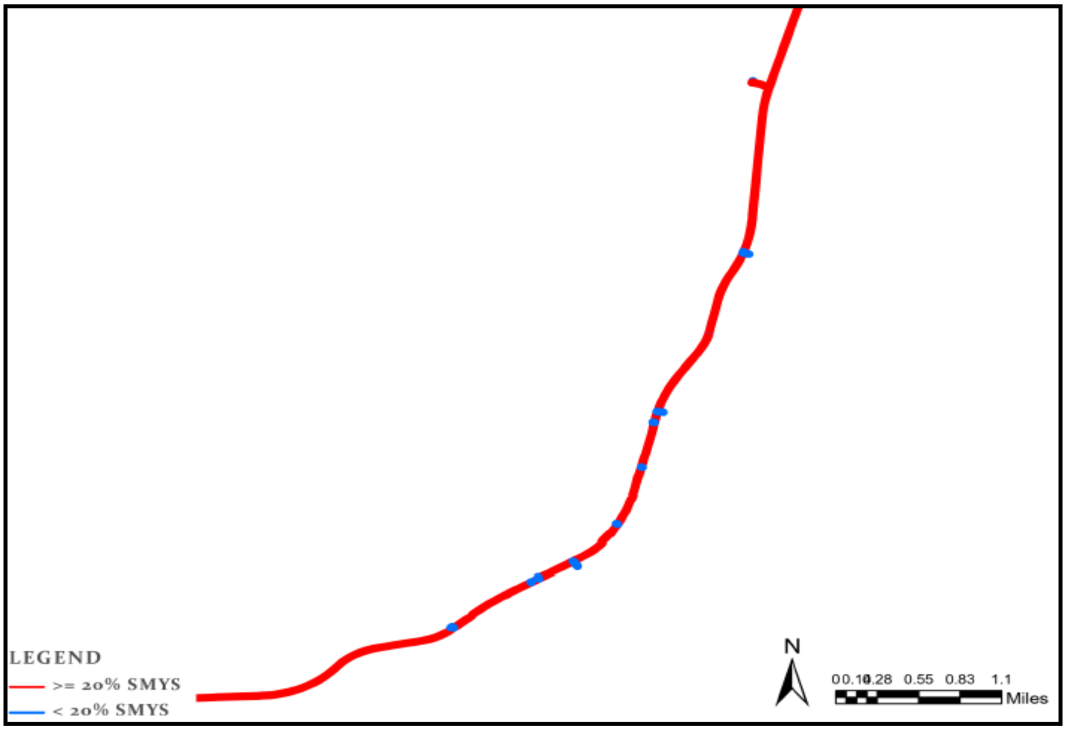
[3] 40 C.F.R. 98.237

- 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:

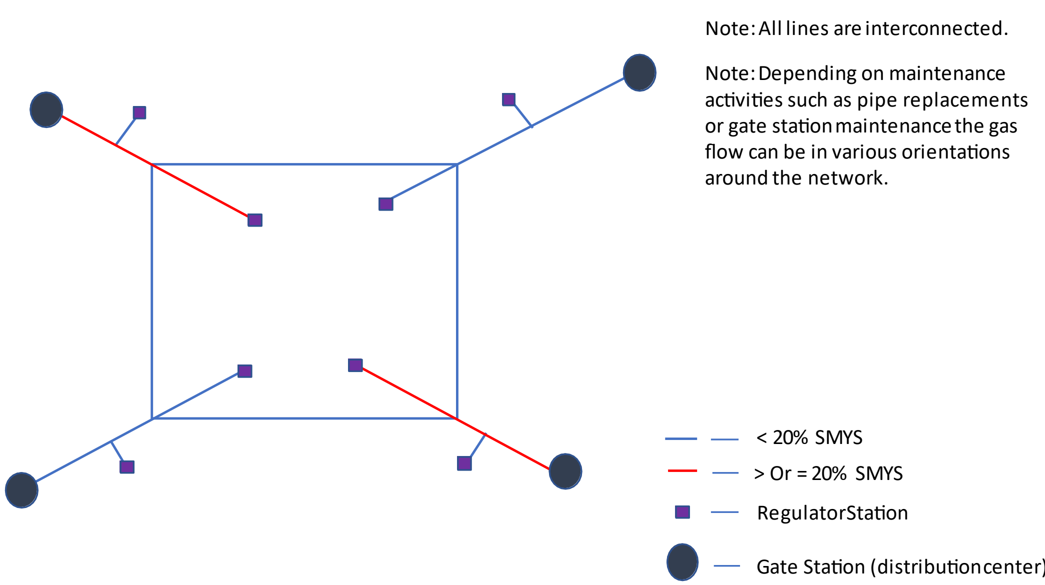


Operators acknowledge that the reverse situation may also be true. That is, a line that is predominantly > 20% SMYS with small segments of < 20% SMYS pipe:



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.

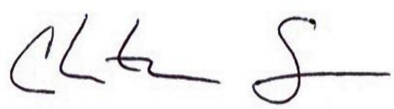
In consideration of the above, AGA seeks reconsideration of the Final Rule's nine-month implementation deadline and requests that PHMSA amend the Final Rule to provide operators 18 months from the date of publication to implement all provisions of the Final Rule.

Conclusion

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.

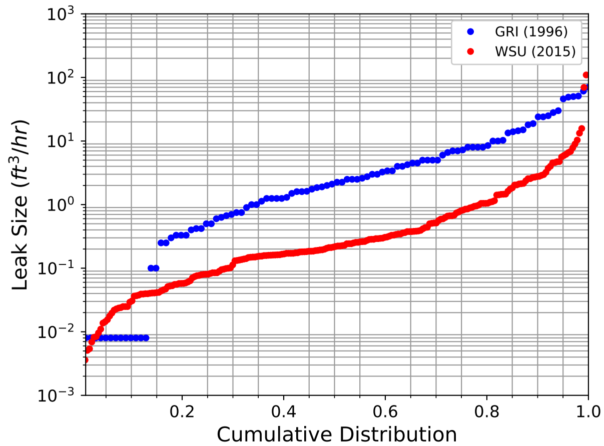

Figure 1: Cumulative distribution of leak sizes for leaks in a gas distribution network reported by Harrison et al., GRI (1996) and Lamb et al., WSU (2015).

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

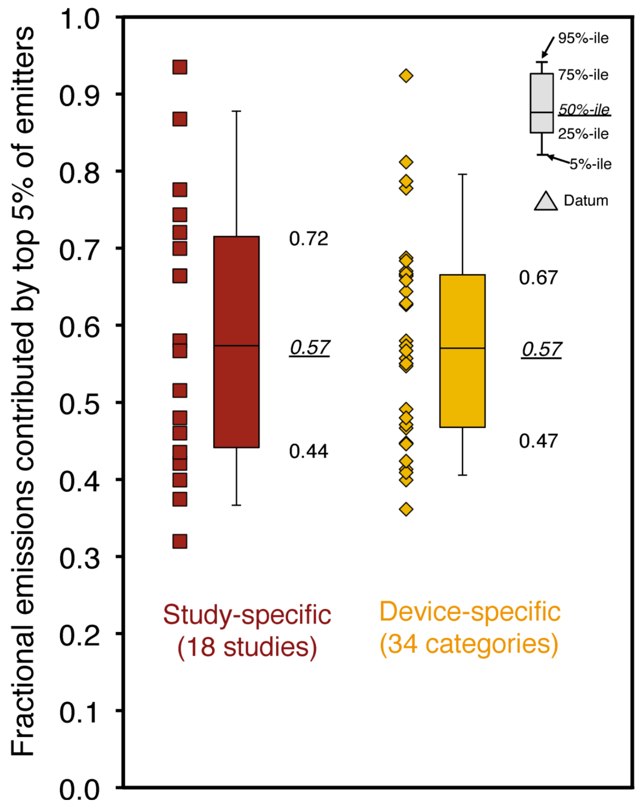

Figure 2: Share of methane emissions contributed by top 5% of emitters. Figure reproduced from Brandt et al.

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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.

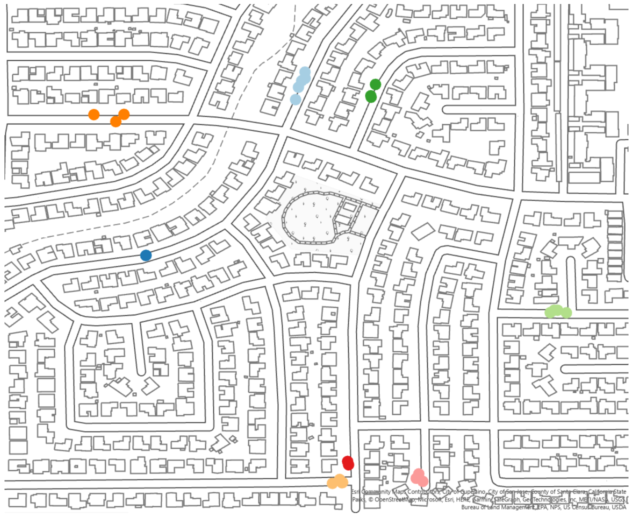


Figure 3: Example of geospatial clustering to associate one or more detections with a source. Each point represents the location where a single plume was detected. Measurements that are clustered together are shown by like colors.

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.

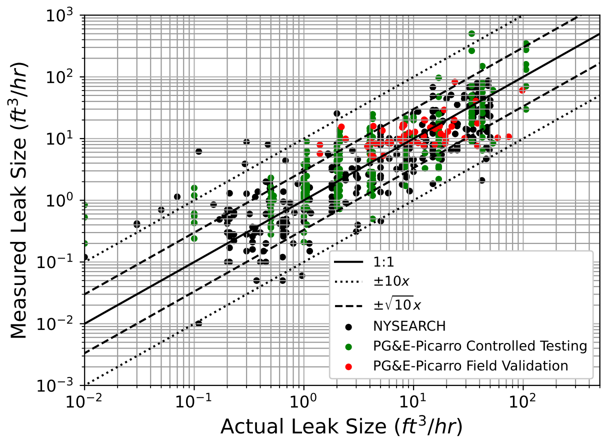


Figure 4: Validation testing unity plot. Quantification system measurements versus actual leak sizes.

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.

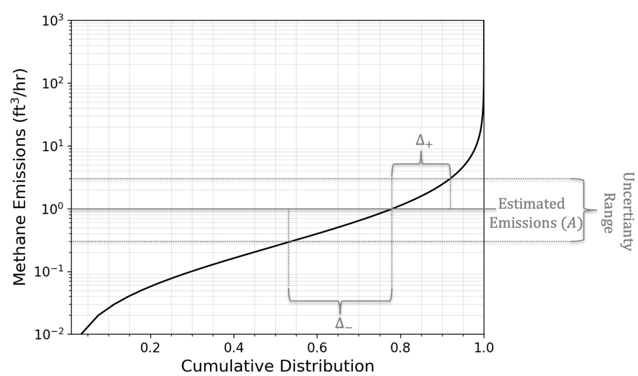


Figure 5: A single leak measured at A=1 ft^3/hr with a $\pm\sqrt{10}$x uncertainty from a skewed distribution will have a larger probability to be overestimated (Δ_-) than underestimated (Δ_+).

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} $\mathrm{ft}^3/\mathrm{hr}$. 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.

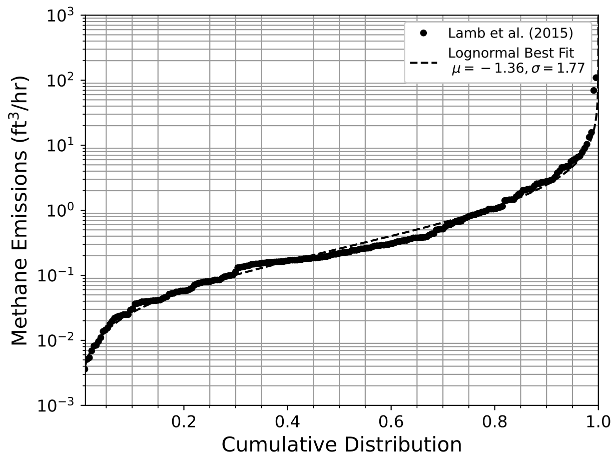


Figure 6: Experimental data from WSU fit to a lognormal distribution

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 ($\mathrm{ft}^3/\mathrm{hr}$)						
	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%
			$[0, 0.1[$	$[0.1, 1[$	$[1, 10[$	$[10, \infty[$
			B_{-2}	B_{-1}	B_0	B_1
			Measured Leak Size ($\mathrm{ft}^3/\mathrm{hr}$)			

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 ($\mathrm{ft}^3/\mathrm{hr}$)						
	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%
			$[0, 0.1[$	$[0.1, 1[$	$[1, 10[$	$[10, \infty[$
			A_{-2}	A_{-1}	A_0	A_1
			Actual Leak Size ($\mathrm{ft}^3/\mathrm{hr}$)			

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 $\mathrm{ft}^3/\mathrm{hr}$) is 5% compared to 2% of actual large leaks. Correspondingly, the average flow rate of leaks detected as large leaks is 10.0 $\mathrm{ft}^3/\mathrm{hr}$ compared to 25.2 $\mathrm{ft}^3/\mathrm{hr}$ 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 (ft^3/hr)	% Measurements $P\langle B_j\rangle$	Average Flow Rate in Bin (ft^3/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:

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

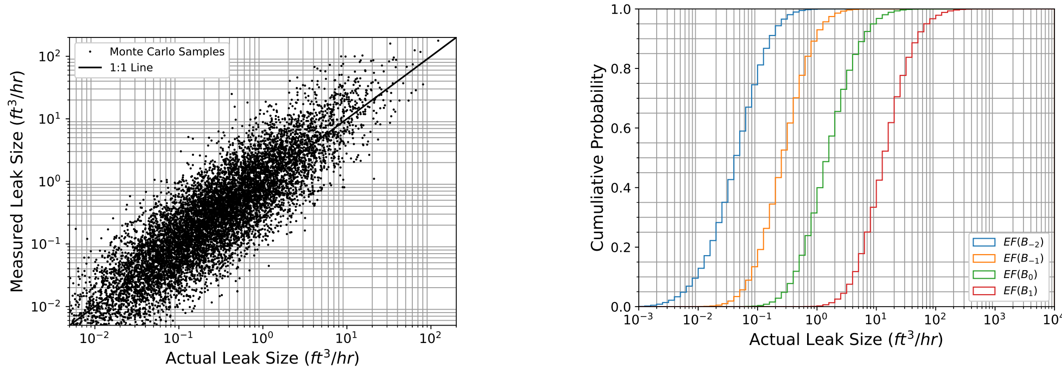
with $\forall i, \sum_j P\langle B_j|A_i\rangle = 1$. Then:

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

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.

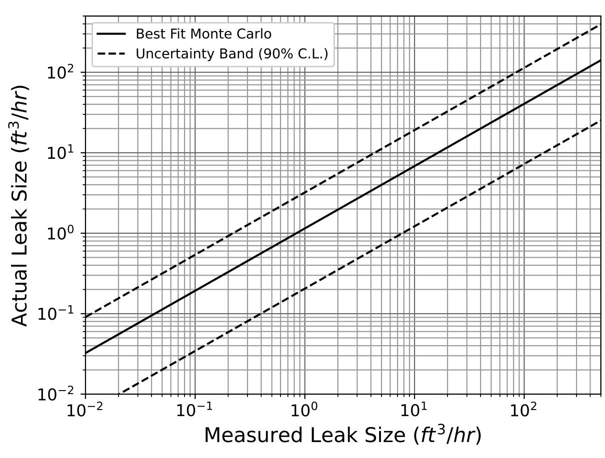


Figure 8: A relationship between actual leak size and measured leak size for leaks in a gas distribution network. This relationship is called $AdjFlow$.

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$^{\mathrm{rd}}$-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:

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

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

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

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:

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

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 ft^3/hr is assigned with the emission factor $EF(B_1)$=10.0 ft^3/hr and leaks measured by the system as less than 10 ft^3/hr are assigned with the emission factor $EF(\bar{B}_1)$=0.73 ft^3/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 $\geq$ 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 $\geq$ 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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