BEFORE THE
UNITED STATES DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
WASHINGTON, D.C.

Pipeline Safety: Gas Pipeline Leak Detection and Repair	)	Docket No. PHMSA-2021-0039 RIN: 2137-AF51

COMMENTS ON PIPELINE SAFETY: GAS PIPELINE LEAK DETECTION AND REPAIR

FILED BY
AMERICAN GAS ASSOCIATION
AMERICAN PETROLEUM INSTITUTE
AMERICAN FUEL & PETROCHEMICAL MANUFACTURERS
AMERICAN PUBLIC GAS ASSOCIATION
GPA MIDSTREAM ASSOCIATION
INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA
NORTHEAST GAS ASSOCIATION

August 16, 2023

Table of Contents

Pipeline Safety: Gas Pipeline Leak Detection and Repair
Notice of Proposed Rulemaking
Docket No. PHMSA-2021-0039

I. Introduction

The American Gas Association (AGA)[1], American Public Gas Association (APGA)[2], Interstate Natural Gas Association of America (INGAA)[3], American Petroleum Institute (API)[4], GPA Midstream[5], American Fuel & Petrochemical Manufacturers (AFPM)[6], and Northeast Gas Association (NGA)[7] (jointly "the Associations") submit these comments for consideration by the Pipeline and Hazardous Materials Safety Administration (PHMSA) regarding PHMSA's Notice of Proposed Rulemaking, "Pipeline Safety: Gas Pipeline Leak Detection and Repair" ("proposed rule" or "NPRM")[8].

---

[1] Founded in 1918, AGA represents more than 200 local energy companies committed to the safe and reliable delivery of clean natural gas to more than 180 million Americans. AGA is an advocate for natural gas utility companies and their customers and provides a broad range of programs and services for member natural gas pipelines, marketers, gatherers, international natural gas companies, and industry associates. Today, natural gas meets more than one third of the United States' energy needs.

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

[3] INGAA is a trade association that advocates regulatory and legislative positions of importance to the interstate natural gas pipeline industry. INGAA is comprised of 26 members, representing the vast majority of the U.S. interstate natural gas transmission pipeline companies. INGAA's members operate nearly 200,000 miles of pipelines and serve as an indispensable link between natural gas producers and consumers.

[4] API is the national trade association representing all facets of the oil and natural gas industry, which supports 9.8 million U.S. jobs and 8 percent of the U.S. economy. API's more than 625 members include large integrated companies, as well as exploration and production, refining, marketing, pipeline, and marine businesses, and service and supply firms. They provide most of the nation's energy and are backed by a growing grassroots movement of more than 25 million Americans.

[5] Shaping the U.S. midstream energy sector since 1921, GPA Midstream sets standards for natural gas liquids; develops simple and reproducible test methods to define the industry's raw materials and products; manages a worldwide cooperative research program; provides a voice for our industry on Capitol Hill; and is the go-to resource for technical reports and publications.

[6] AFPM is the leading trade association representing the makers of the fuels that keep Americans moving and the petrochemicals that are the essential building blocks for modern life. Our industries make life better, safer, healthier and — most of all — possible.

[7] NGA is a regional trade association that focuses on education and training, technology research and development, operations, planning, and increasing public awareness of natural gas in the Northeast U.S. It represents natural gas distribution companies, transmission companies, liquefied natural gas importers, and associate member companies that provide natural gas to over 13 million customers in nine states

[8] Pipeline Safety: Gas Pipeline Leak Detection and Repair, Federal Register Vol. 88, No. 96 (May 18, 2023).

Pipeline safety continues to be the top priority of the Associations and their members. The Associations support the intent of the proposed rule and share PHMSA's goal of addressing methane emissions. However, the Associations have significant concerns with PHMSA's proposed rule, its proposed implementation of the Congressional mandates included in sections 113 and 114 of the Protecting our Infrastructure of the Pipelines and Enhancing Safety Act of 2020 ("PIPES Act"), and its expanded interpretation of its regulatory reach in the NPRM which is far beyond Congress' mandate. In fact, several of the proposed requirements contradict the clear directives included in the PIPES Act. Some of the Associations' more significant concerns with the proposed rule include:

- The six-month timeframe proposed in the NPRM is not realistic or achievable. PHMSA should provide a three-year effective date for the Final Rule.
- Eliminating all detectable leaks, including those so inconsequential that they pose no potential hazard to public safety and no or de minimis impact on the environment;
- Managing all detectable leaks as hazardous leaks;
- Exceeding the authority in the PIPES Act of 2020 in selecting the leak detection requirements;
- Using "advanced leak detection" methodologies that only yield small incremental improvements in public safety or environmental safety;
- Requiring unrealistic timeframes for operators to implement and train to the many significant new actions and new technologies and equipment required by the proposed rule;
- Unreasonable and, in some cases, infeasible standards for alternative detection technology and the necessity to align those requirements with EPA's anticipated final rule, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review", and other regulations aimed at reducing methane emissions. Specifically, the Associations recommend PHMSA review and consider the tiered matrix methane emissions monitoring approach in Table 1 of the Environmental Protection Agency's (EPA) proposed rulemaking for Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources (EPA-HQ-OAR-2021-0317) as a baseline and adjust the detection threshold and frequency of patrols/surveys to meet the intent of the PHMSA rule, considering the aerial survey methodology for the vast majority of associated inspections;
- Inapplicability of pure hydrogen in the rulemaking due to limitations in hydrogen sensor technologies, which require further R&D and development before pipeline operators can effectively implement these technologies as part of an effective, practical hydrogen leak detection and repair program;
- PHMSA's flawed accounting of the costs and benefits of the proposed rule;
- For Offshore pipelines, BSEE has recently requested emissions reporting for DOT operator transportation platforms on the OCS. They further require written reporting for [30 CFR 250.188(9)(b) (2)]. All gas releases that initiate equipment or process shutdown. There are proposals in this rule that would overlap with these DOI BSEE requirements leading to duplicative reporting and general confusion. PHMSA should coordinate with BSEE on requirements for offshore pipeline reporting; and

- Offshore transmission and offshore gathering lines should be exempt, due to the difficulty in assessing leaks with proposed technologies in rule used for onshore lines and are unlikely to impact people or the environment. Additionally, post repair check would be challenging to be done underwater.

Extensive changes must be made to PHMSA's proposed rule in order for it to be consistent with Congress' intent in the PIPES Act of 2020 and for it to be technically and economically feasible. The comments offered by the Associations below provide alternatives, recommendations, and modifications that, if implemented, can help accomplish both goals, are technically feasible, economically viable, seek better alignment with EPA rules that are already regulating methane emissions, and are clearly consistent with Congress' intent in the PIPES Act. Additionally, these recommendations would appropriately balance public safety and environmental protection and would protect the interests of the more than 200 million Americans and our global allies who rely on natural gas to be delivered safely, reliably, and affordably.

II. PHMSA's Misinterpretation of the PIPES Act of 2020

The Associations support the PIPES Act of 2020 and initiatives which protect the public and the environment. The Associations worked closely with Congress in the development of PIPES Act Section 113, "Leak detection and repair," and Section 114, "Inspection and maintenance plans," which PHMSA seeks to implement and codify in regulation in the proposed rule. Unfortunately, the proposed rule does not accurately reflect Congress's intent of the PIPES Act[9].

Section 113 of the PIPES Act requires operators of regulated non-rural gas gathering lines, new and existing gas transmission pipeline facilities, and new and existing gas distribution pipeline facilities to conduct leak detection and repair programs that meet the need for gas pipeline safety and protecting the environment. In the requirements for the leak detection and repair programs, Congress specified that the programs should focus on the ability to "identify, locate, and categorize all leaks that – (i) are <u>hazardous</u> [emphasis added] to human safety or the environment; or (ii) have the potential to become explosive or otherwise hazardous to human safety." Section 113 also requires operators to use advanced leak detection technologies and practices and "include a schedule for repairing or replacing each leaking pipe, <u>except a pipe with a leak so small that it poses no potential hazard"</u> [emphasis added], with appropriate deadlines. Therefore, Congress made it clear that not all leaks were to be deemed hazardous, and not all leaks should be required to be repaired. As the proposed rule is written, a leak would only be exempted from the "hazardous" designation and from repair scheduling if it is so small that <u>it cannot be detected</u> [emphasis added] by the very low minimum leak detection sensitivity threshold proposed by PHMSA. As described in detail below, PHMSA's proposed rule does not follow the clear intent of Congress for Section 113.

[9] See, for example, the letter submitted by the U.S. House of Representatives Committee on Transportation and Infrastructure submitted to this docket expressing significant concerns with certain aspects of PHMSA's proposed rule.

Section 114 of the PIPES Act requires that the inspection and maintenance plans carried out by owners and operators of gas and hazardous liquid pipeline facilities meet the requirements of the leak detection and repair regulations promulgated pursuant to Section 113 of the statute. The Congressional summary of H.R. 133, which contains the PIPES Act of 2020, makes it clear that Congress envisioned that a rulemaking on Section 113 be completed before Section 114 would go into effect.[10] Section 114 requires that PHMSA consider in its review of an operator's inspection and maintenance plan "the extent to which the plan will contribute to - (i) public safety; (ii) eliminating hazardous leaks and minimizing releases [emphasis added] of natural gas from pipeline facilities; and ''(iii) the protection of the environment". Like in Section 113, Congress was focused on hazardous leaks and did not deem all leaks to be hazardous.

Furthermore, Section 114 of the PIPES Act 2020 required several steps to be taken before PHMSA updated its regulations. For instance, Congress required PHMSA to submit to Congress a report within 18 months after the Act's date of enactment discussing the best available technologies or practices to prevent or minimize the release of natural gas, without compromising safety, when making planned repairs, replacements, or maintenance, and when intentionally venting or releasing natural gas including during blowdowns; as well as pipeline facility designs that mitigate the need to intentionally vent natural gas. To date, this report has neither been published nor submitted to Congress. After this report is completed, PHMSA is required within 180 days to update its regulations as it determines appropriate.

Moreover, Congress required the Comptroller General to prepare a report no later than 1 year after PHMSA completed its inspections of pipeline operators mandated by Section 114 to focus on evaluating PHMSA's procedures used to conduct inspections and to provide recommendations for further ways to minimize releases of natural gas from pipeline facilities without compromising pipeline safety. Then, PHMSA is directed to prepare a report in response to the Comptroller General's findings and recommendations. To date, neither the Comptroller General report nor PHMSA's response have been completed. The Associations believe that the current proposed rule includes several provisions that seek to regulate areas that Congress intended to be studied further prior to PHMSA moving forward with the rulemaking process. The Associations believe that PHMSA's current rulemaking would be well informed by the studies mandated by the PIPES Act of 2020.

III. Industry's Commitment to Reducing Methane Emissions and Addressing Climate Change.

The Associations and their members share the Administration's goal of reducing greenhouse gas (GHG) emissions. Natural gas plays an important role in the clean energy transition and is an essential component of that transition.

[10] H.R. 133 DIVISION-BY-DIVISION SUMMARY OF AUTHORIZING MATTERS, Page 7 - 8: https://appropriations.house.gov/sites/democrats.appropriations.house.gov/files/Summary%20of%20H.R.%20133%20Authorizing%20Matters.pdf

Natural gas and the extensive infrastructure network that supports it have been increasingly important cornerstones of America's energy economy for more than a century and will be needed into the future. Today, hundreds of millions of Americans rely on natural gas infrastructure and the energy it delivers to heat their homes, power their businesses, and manufacture goods. Policymakers' increased emphasis on addressing climate change and reducing emissions has complemented the natural gas industry's focus on safety and reliability and enabled a steep decline in methane emissions through pipeline replacement and modernization efforts as well as reducing the amount of gas vented to the atmosphere[11]. The operators of America's natural gas networks are working to address the challenges of climate change now and into the future.

The Associations and their members are committed to reducing GHG emissions through implementation of reasonable leak detection and repair requirements consistent with the congressional mandate, smart innovation, new and modernized infrastructure, instituting best practices for emission reductions and the faster detection and repair of leaks, and deployment of advanced technologies that maintain reliable, resilient, and cost-effective energy service choices for consumers. In collaboration with policymakers and regulators, the Associations support the modernization of the nation's natural gas infrastructure to distribute safe, reliable, and cost-effective energy.

Since 2005, carbon dioxide emissions in the electric power sector have declined by about 35 percent, with a switch from coal to natural gas accounting for about two-thirds of the decline[12]. Moving forward, natural gas will continue to enable the United States to maintain electric reliability while expanding its fleet of renewable energy resources. The North American Electric Reliability Council concludes that "*[n]atural gas is the reliability fuel that keeps the lights on, and natural gas policy must reflect this reality*[13]."

Methane emissions from natural gas distribution systems across the country have declined by 70 percent from 1990 – 2021[14]. The data reflects the significant work AGA and APGA member gas utilities have been completing to modernize their systems and implement best practices.

Each Association and its members have publicly committed to reducing GHG emissions. Below are some of the more recent, and historic, actions that have been taken by the Associations and their members:

---

[11] Overall, methane emissions from the natural gas distribution segment have been declining since 1990, even as the size of the system has grown significantly. Methane emissions from distribution systems were 13 MMTe in 2021, a decline of 70 percent from 1990 levels. This drop occurred as the industry added 815,100 miles of pipelines to serve 22.3 million more customers. *See* 2023 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2021 (April 15, 2023) (2023 GHGI).

[12] Congressional Budget Office, *Emissions of Carbon Dioxide in the Electric Power Sector* (Dec. 2022), https://tinyurl.com/6pptpedr.

[13] NERC, Long Term Reliability Assessment at 5 (Dec. 2021), https://tinyurl.com/csu6zwsb.

[14] *See* 2023 GHGI.

AGA

AGA and its members are committed to reducing GHG emissions through innovation, investment in technology, energy efficiency measures, renewable natural gas development and use, modernization of the natural gas infrastructure, third-party damage prevention programs, and promotion of best practices for reducing methane emissions[15]. For example:

- AGA worked with its members to develop a Blowdown Emission Reduction White Paper in 2020 to help share learnings and best practices[16] .
- 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 its members helped establish the EPA Methane Challenge program, which calls on participating companies to set challenging best management practice (BMP) goals for reducing methane emissions across their operations. Alternatively, participating companies have set goals for reducing emissions to achieve low methane emissions intensity levels under the ONE Future track of the Methane Challenge Program. All the founding natural gas distribution participants in the Methane Challenge are AGA member companies.
- AGA established an Excavation Damage Executive Task Force to create resources and guidance for reducing excavation damage, a significant cause of methane emissions from distribution systems.
- AGA Member companies are committing millions of dollars annually on research and development of technologies to reduce methane emissions and transition our industry to a low-carbon future.

The methane emissions strategies our members shared in Natural Gas STAR and the commitments they made in the Methane Challenge program have helped to reduce methane emissions from U.S. natural gas distribution systems by 70 percent from 1990 to 2021, down to just 0.1 percent of annual produced natural gas[17].

AGA and its members have also long supported measures for improving the transparency and accuracy of methane emissions 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.

---

[15] *See* AGA's Climate Change Position Statement: https://www.aga.org/natural-gas/environment/climate-change-commitment/. (Last accessed August 13, 2023) and enclosed as Appendix A.
[16] *See* AGA Blowdown Emission Reduction White Paper (2020) at https://www.aga.org/wp-content/uploads/2022/12/aga-blowdown-emissions-reduction-white-paper-final-8.5.20.pdf. (Last accessed August 13, 2023) and enclosed as Appendix B.
[17] *See* 2023 GHGI.

To encourage AGA members and upstream suppliers to publicly disclose their methane emissions in a robust and comparable way, AGA developed the Natural Gas Sustainability Initiative (NGSI)[18]. 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. Striving to reduce methane emissions from the natural gas supply chain is a critical part of our members' efforts to lower their own emissions.

In February 2022, AGA published a study, *Net-Zero Emissions Opportunities for Gas Utilities* (Net Zero Study)[19], which presents a national-level approach that leverages the advantages of gas technologies and distribution infrastructure. The study underscores the range of scenarios and technology opportunities available as the nation, regions, states, and communities develop and implement ambitious emissions reduction plans. AGA is submitting a copy of this important study as Appendix C to these comments.

The Net Zero study evaluates four illustrative pathways using different GHG reduction strategies that gas utilities can deploy to achieve net-zero goals[20]. These strategies include methane emission reductions, energy efficiency, innovative technology, and net-zero gaseous fuels such as renewable natural gas (RNG) and clean hydrogen. The approach taken by each gas utility will likely vary depending on factors such as differing geography, structure, facilities, state regulatory oversight and customer base. However, while different company plans will vary as to the degree to which they deploy specific strategies, all will likely include some combination of strategies from all four categories – including technologies and procedures for reducing the gas utility's scope 1 direct methane emissions.

The key findings in the study include the following:

1. Pathways that utilize natural gas and the vast utility delivery infrastructure offer opportunities to incorporate renewable and low-carbon gases, provide optionality for stakeholders, help minimize customer impacts, maintain high reliability, improve overall energy system resilience, and accelerate emissions reductions.
2. The ability of natural gas infrastructure to store and transport large amounts of energy to meet seasonal and peak day energy use represents an important and valuable resource that needs to be considered when building pathways to achieve net-zero GHG emissions goals.
3. Continued utilization of natural gas and the vast utility delivery infrastructure can increase the likelihood of successfully reaching net-zero targets while minimizing customer impacts.

---

[18] *See* https://www.aga.org/research-policy/natural-gas-esg-sustainability/ (last accessed Aug. 15, 2023).
[19] "Net-Zero Emissions Opportunities for Gas Utilities," AGA, February 8, 2022, available at Pathways to Net-Zero - American Gas Association (aga.org) and included as Appendix C.
[20] *Id*., see p. 9, Exhibit E.s.3.

4. The U.S. can achieve significant emissions reductions by accelerating the use of tools available today, including high-efficiency natural gas applications, renewable gases, methane reduction technologies, and enhanced energy efficiency initiatives.
5. Large amounts of renewable and low-carbon electricity and gases, and negative emissions technologies, will be required to meet an economy-wide 2050 net-zero target.
6. Supportive policies and regulatory approaches will be essential for natural gas utilities to achieve net-zero emissions.

APGA

APGA's membership formalized their commitment to reduce methane emissions through the APGA Commitment to Environmental Stewardship,[21] included as Appendix D. 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 sites and city gate stations where appropriate and feasible and replacing aging infrastructure that is known to have a higher probability of methane leaks.

APGA also developed an Environmental Roadmap for public gas systems, included as Appendix E. The Environmental Roadmap is a voluntary written qualitative assessment tool for public gas systems to:

- Determine the current utility-specific status of environmental stewardship;
- Compare environmentally sustainable actions and potentially obtain ideas from other LDCs;
- Facilitate communication of the many positive actions and initiatives your utility is or will be taking to continue to drive down methane emissions; and
- Help set goals for continuous environmental sustainability efforts.

APGA and its members support and participate in EPA's Methane Challenge program. APGA also has joined the Gas Technology Institute's (GTI) Center for Methane Research (CMR), it hosts roundtables and webinars for members to learn about best practices and new technologies for methane detection and reduction.

APGA members are demonstrating their commitment to methane emission reduction through APGA's voluntary programs and awards, such as the System Operational Achievement Recognition Program and the APGA Award for Environmental Stewardship.

INGAA

INGAA members have historically implemented measures to minimize GHG emissions. According to data reported to USEPA, these efforts have resulted in a reduction of CO_2-equivalent emissions from transmission and storage compressor stations that is the equivalent of removing more than one million passenger vehicles from the road. INGAA and its members have made a series of

[21] https://www.apga.org/viewdocument/apga-members-are-committed-to-envir, also included as Appendix D.

Methane Emissions Commitments, including the implementation of measures such as those found in EPA's Natural Gas STAR program to minimize methane emissions from pipeline blowdowns, pneumatic controllers, and transmission and storage compressor stations as well as transparent reporting.[22] Many INGAA members are also members of EPA's Natural Gas STAR and Methane Challenge Programs, ONE Future Coalition, The Environmental Partnership and various state GHG reduction programs.[23]

INGAA commitments include an active effort to do even more to address climate change by supporting renewables, as well as new and innovative technologies and process enhancements that will further reduce emissions. Working together, we are determined to support sound public policies that protect the environment while ensuring a safe, reliable, and resilient energy transmission system that provides the affordable energy so many of our businesses and families need. INGAA's leadership has led to the development of forward-thinking policies that are driving continuous improvement in the natural gas industry. Those policies are contained in INGAA's 2021 Vision Forward Statement, INGAA Greenhouse Gas Emissions Commitments, and INGAA's Climate Report.

The INGAA Greenhouse Gas Emissions Commitments include the following operational and maintenance practices that are reducing INGAA members' overall climate footprint:

> **Pipelines**: Conducting surveys on transmission pipelines at least once per calendar year to detect leaks and make environmentally beneficial repairs or take proactive measures to mitigate emissions associated with the leaks identified. INGAA members commit to using leak detection methods, technologies or other agency-approved methods during these surveys, including handheld equipment, equipment mounted on mobile platforms, or other technologies as appropriate.
>
> **Blowdowns**: Maintaining safe and efficient operations while minimizing methane emissions from interstate natural gas pipelines during maintenance, repair or replacement (a practice commonly referred to as a "blowdown") by evaluating and implementing voluntary practices, such as reducing pipeline pressure or utilizing cross-compression prior to conducting planned maintenance and other recommendations found in the U.S. Environmental Protection Agency's (EPA's) Natural Gas STAR Program.
>
> **Pneumatic Controllers**: Selecting air-driven, or no-bleed, low-bleed or intermittent pneumatic or electric controllers when installing new controllers, unless a different device is required for safe or reliable operations. For existing high-bleed pneumatic controllers, INGAA members will evaluate the feasibility of replacing them with air-driven, no-bleed, low-bleed, intermittent pneumatic or electric controllers. INGAA members shall repair or replace malfunctioning pneumatic controllers.
>
> **Storage & Compressor Stations**: Minimizing methane emissions from natural gas transmission and storage compressor stations, where practical, such as, during planned

[22] See INGAA's Methane Emissions Commitments at https://www.ingaa.org/File.aspx?id=38582
[23] See description of methane initiatives in which INGAA members participate at https://www.ingaa.org/File.aspx?id=37866&v=e53e63b4

maintenance, when conducting the PHMSA required emergency shutdown system tests, or through installing and utilizing vent gas recovery (VGR) systems.

Rod Packing Seals: Minimizing methane emissions from rod packing seals on all reciprocating compressors at transmission and storage facilities. Member companies agree to replace rod packing on all transmission and storage reciprocating compressors by utilizing one of the following options: (1) a condition-based replacement approach; (2) replacing packing every 26,000 hours of operation; (3) replacing packing 36 months from the date of the most recent rod packing replacement or (4) installation and utilization of rod packing vent gas recovery (VGR).

Leak Surveys: Conducting leak surveys at transmission and storage compressor stations. INGAA member companies shall evaluate leaks detected during such surveys and take corrective actions to reduce emissions by repairing or replacing leaking valves and fittings. INGAA member companies will perform leak surveys using optical gas imaging (OGI) cameras or other agency-approved methods at all transmission and storage compressor stations owned and operated by INGAA member companies before January 1, 2023. Subsequent leak surveys shall be conducted at least every two years or more frequently as otherwise required by law.

Natural Gas Storage Wells: Minimizing methane emissions from natural gas storage wells and inspecting all natural gas storage wells owned and operated by INGAA members for leaks at least annually.

Reducing CO2 emissions from natural gas transmission and storage compressor stations while maintaining safe operations and meeting contractual and reliability commitments.

R&D: Supporting the development of new technology and effective practices and sharing information.

By investing in and adopting innovative technologies and encouraging and working with other portions of the natural gas value chain to do the same, we can drive emissions even lower. INGAA's members are committed to reducing both the carbon intensity of the natural gas network and supporting the reduction of the absolute quantity of global GHG emissions derived from the energy we deliver. Reducing both the carbon intensity and the overall emissions will be important as economies around the world convert to a lower carbon future.

INGAA analyzed the methane emissions data that the transmission and storage sector reported to EPA between 2011-2019 under Subpart W of the mandatory Greenhouse Gas Reporting Rule. The data showed that between 2011 and 2019, average methane emissions from transmission and storage natural gas compressor stations decreased by 31 percent, even with the number of these reporting facilities increasing from 465 to 661 over the same time period. This reduction is equivalent to removing a total of 1.5 million passenger vehicles from the road between 2011 and 2019.

INGAA's members are determined to modernize our nation's interstate natural gas delivery network infrastructure, reduce emissions from our operations and address the climate crisis by working together as an industry towards achieving net-zero GHG emissions by 2050. INGAA has developed multiple white papers for its member companies to reduce methane emissions and reduce environmental impacts. Those documents cover topics such as Transportation and Storage of Hydrogen, Transportation and Storage of RNG, Managing Methane Emissions from Maintenance and Integrity Work, and Regulatory Acceptance of Non-Traditional Pipe. These documents support reduction in greenhouse gas emissions by capturing waste methane and putting it to use in our natural gas pipeline system or seeking processes to minimize natural gas venting during integrity related work. Regulatory acceptance of non-steel pipe would provide operators with more options to minimize environmental impacts by using existing steel pipe and installing a composite pipe inside existing pipe to safely deliver gas. Lastly, the existing natural gas system can support the transition to hydrogen gas delivery and storage to reduce carbon emissions.

API

The natural gas and oil industry is working to further reduce emissions and keep methane in the pipe throughout its operations. Through individual company actions and collective, industry-led initiatives like **The Environmental Partnership**, our industry is working to better understand, detect, and mitigate emissions by developing new technologies and practices. Launched by API in 2017, The Environmental Partnership is an industry-led coalition of oil and natural gas companies that have voluntarily committed to continuously improve the industry's environmental performance. Through the Partnership, companies are taking action by implementing performance programs within their organizations, learning and sharing best practices and new technologies, and fostering collaboration. Its key value to the industry is providing a platform for operator peer-to-peer sharing across the four critical elements of facility design, operations and maintenance, measurement and detection, and data integrity.

Since its inception, the Partnership has quadrupled in industry participants and now represents more than 70% of total U.S. onshore natural gas and oil production. From **leak detection and repair programs** to collaboration with leading research institutions and an **initiative to reduce flaring**, The Partnership is leading the way toward a cleaner future.

API member companies are committed to reducing methane emissions as a key component of responsibly producing oil, natural gas and petrochemical products. Companies are working diligently to reduce methane emissions through innovative facility design, improvements in operational practices and procedures, advancements in detecting and measuring emissions, and improved accuracy in emissions reporting data. By strategically focusing efforts on these four critical areas, our industry is establishing a blueprint to continuously drive methane emissions reductions.

- **Facility Design:** Our industry is investing resources to evaluate, enhance, and optimize facility designs to minimize methane leakage, and identify cost-effective opportunities to retrofit existing facilities.

- **Operations and Maintenance:** Through investments in research and collaboration, our industry is identifying and advancing improvements in operations and maintenance practices and procedures to drive reductions in methane intensity.

- **Measurement and Detection:** The natural gas and oil industry innovates monitoring, detection, and measurement technologies and techniques to enhance and expand methane detection and emission reduction capabilities.

- **Data Integrity:** Trust in the industry's reported methane inventory is a priority for our members. We support voluntary efforts in measurement, reporting and verification (MRV) to accurately quantify emissions. This focus includes sharing best practices regarding new and evolving independent data verification services and continued advances in methane monitoring, detection, and measurement technologies and protocols.

GPA Midstream

GPA Midstream has an annual Environmental Excellence Award to encourage its members to use best practices and innovation to improve environmental performance, including methane emissions reductions[24].

AFPM

AFPM represents the U.S. refining, petrochemical, and midstream industries. *AFPM members are committed to reducing emissions and addressing climate change by improving their operations and the products they produce.* In the last decade, U.S. refineries invested more than $100 billion to improve refinery efficiency, reduce emissions, and produce cleaner fuels[25] . As a result, emissions were dramatically reduced; in fact, reported total U.S. carbon intensity of operating refineries decreased by 12 percent during this period[26]. Despite historic expansion, U.S. petrochemical greenhouse gas (GHG) emissions remained relatively flat[27]. Industry is not complacent with these reductions. AFPM members are setting their sights even higher, making historic commitments to significantly reduce emissions over time. Specifically, members are:

- Advancing breakthrough technologies, including carbon capture, sequestration, and utilization. Carbon capture and storage (CCS) could reduce up to 15 percent of global emissions by 2040, and global decarbonization efforts are estimated to double in cost without CCS, according to the U.N. Intergovernmental Panel on Climate Change (IPCC)[28].

- Investing billions of dollars in new products and processes to reduce the carbon footprint of the fuel and petrochemical manufacturing industries. To meet increasing demand for lower-carbon fuels increases, U.S. fuel refiners continue to scale and make new investments and breakthroughs in fuels such as renewable diesel, sustainable aviation fuel (SAF), and lower-carbon hydrogen. SAF, for example, has the potential to reduce lifecycle GHG emissions by up to 80 percent, compared with conventional jet fuel[29].

- Incorporating renewable feedstocks into their products to lower their carbon footprint without compromising quality or performance[30].

---

[24] See GPA Midstream Environmental Excellence Award at
https://www.gpamidstream.org/awards/environmental-excellence-award
[25] Industrial Information Research
[26] John Beath Environmental
[27] U.S. Environmental Protection Agency
[28] International Energy Agency
[29] International Air Transport Association
[30] Learn more about AFPM Member's efforts to address GHG Emissions and Climate Change
https://www.afpm.org/data-reports/publications/sustainability-report

- Employing and planning to deploy a full spectrum of low-emission energy resources – from wind and solar to small modular nuclear technology – and improving processes to maximize energy efficiency and reduce our carbon footprint.

- Protecting surrounding communities by utilizing technologies that enable early detection and mitigation of emissions sources, even small ones.

While the roadmaps to achieve further reductions may vary, these sectors and companies are collaborating with each other, as well as with government, academic institutions, and non-governmental organizations (NGOs), among other stakeholders, to innovate and scale promising technologies that have the potential to drive even more significant emissions reductions.

IV. Participation by the Associations in the Leak Detection and Repair Rulemaking Docket

The Associations have consistently supported PHMSA's technical and rulemaking efforts, and this rulemaking is no exception.

A. Participation in PHMSA's May 5-6, 2021, Public Meeting on Pipeline Leak Detection, Leak Repair, and Methane Emission Reduction

In May 2021, PHMSA held a public meeting on "Pipeline Leak Detection, Leak Repair, and Methane Emission Reduction". As stated in the Federal Register Notice, PHMSA expected "to cover subjects that include examining the sources of methane emissions from natural gas pipeline systems, current regulatory requirements for managing fugitive and vented emissions, industry leak detection and repair practices, and the use of advanced technologies and practices to reduce methane emissions from gas pipeline systems."[31] This discussion was "intended to inform a rulemaking and report to Congress on natural gas pipeline leak detection and repair mandated by Sections 113 and 114 of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020."[32]

From the moment the public meeting was announced, the Associations promoted the event to our members and committed to active participation. AGA, APGA, INGAA, and GPA Midstream all presented during the May 5, 2021, portion of the workshop, demonstrating our support and offered important industry insights and experiences to help guide PHMSA as it drafted its proposed rule. Highlights of each presentation are below:

- AGA showcased how pipeline replacement programs support pipeline safety, reliability, and a reduction in emissions; that excavation damage continues to be a leading cause of pipeline incidents and its impact on the environment (per PHMSA's 2020 data, excavation damage caused the release of approximately 245,000 Mcf, the equivalent of 34 MM miles driven, 15 MM pounds of coal burned, or enough electricity to power over 2600 homes for

[31] Federal Register/ Vol. 86, No. 65 / Wednesday, April 7, 2021 / https://www.govinfo.gov/content/pkg/FR-2021-04-07/pdf/2021-07152.pdf
[32] *Id.*

a year). AGA recommended that PHMSA focus on the repair of larger leaks which could be hazardous to the environment and that PHMSA not detract from current replacement programs[33].

- PHMSA's 2022 annual report indicates that excavation damage is the primary cause of hazardous leaks on both distribution mains and service lines. There were 17,120 hazardous leaks on distribution mains and 65,107 hazardous leaks on distribution services in 2022 alone. For natural gas transmission systems, PHMSA's 2022 annual report data indicates there were 29 leaks due to excavation damage, and 1 leak and 6 failures due to previous damage caused by excavation activity. For gas gathering lines, PHMSA 2022 annual report data indicates there were 11 leaks due to excavation damage and 6 failures due to previous damage caused by excavation activity.

- APGA's representative, Knoxville Utilities Board (KUB), highlighted its success in utilizing Distribution Integrity Management Program (DIMP) to determine what portions of its system need more frequent leak surveys, the resources utilized for those surveys, how its replacement program has led to a dramatic decline in leaks, and the large impact of excavation damage on methane emissions[34].

- INGAA publicly supported the PIPES Act. INGAA highlighted its members historic commitment to minimizing methane emissions and how these efforts have reduced emissions 35% from 1990 to 2019 even while production increased 91% during that time. INGAA recommended that PHMSA's rulemaking consider site specificity, risk specificity, and setting frequency of leak monitoring based on threat level[35].

- GPA Midstream highlighted its work with Congress on Sections 113 and 114 of the PIPES Act, the provisions in each section that pertain to gathering lines, current leak detection and repair requirements for gathering lines, current leak detection and repair practices for gathering lines, and emphasized that PHMSA's future regulation should be risk based and cost effective[36].

Following the public meeting, the Associations submitted comments to the docket[37]. These comments included the following recommendations:

---

[33] Presentation can be found on PHMSA's Pipeline Leak Detection, Leak Repair and Methane Emission Reductions Public Meeting website https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=1139
[34] Presentation can be found on PHMSA's Pipeline Leak Detection, Leak Repair and Methane Emission Reductions Public Meeting website https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=1140
[35] Presentation can be found on PHMSA's Pipeline Leak Detection, Leak Repair and Methane Emission Reductions Public Meeting website https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=1148
[36] Presentation can be found on PHMSA's Pipeline Leak Detection, Leak Repair and Methane Emission Reductions Public Meeting website https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=1145
[37] PHMSA-2021-0039-0008; https://www.regulations.gov/comment/PHMSA-2021-0039-0008 , included in these comments as Appendix F.

- That PHMSA let the “tool fit the task.” A simpler, less costly technology or practice may achieve safety and environmental goals as well or better than a technology that has recently become commercially available;

- The public must remain PHMSA’s top priority during emergencies or in response to issues that affect pipeline integrity. For example, in the PIPES Act of 2020, Congress required operators to eliminate a common mode of failure and cites a relief valve as one appropriate method to achieve this goal[38];

- Focus on large leaks since studies indicate that most methane emissions in any source category are produced by a small minority of leak sources;

- Focus on accelerated replacement of leak-prone pipelines since data proves this has driven down emissions;

- Concentrate efforts to reduce excavation damages to drive down emissions and increase public safety;

- Understand that Grade 1, 2, and 3 leaks focus on the leak’s hazard to public safety. Current leak detection technologies capture the concentration of gas within the atmosphere, which indicates if the concentration is nearing or exceeding the lower explosive limit. For environmental purposes, the flow rate is far more important for determining the volume of methane emitted to atmosphere;

- Consider the impact of new regulatory requirements on ratepayers (e.g., low-income, historically disadvantaged communities); and

- Avoid prescriptive regulations that could limit or impede technological innovation

Additionally, the Associations provided information on the following topics:

- Industry initiatives to reduce methane emissions;

- Existing and proven operational practices that minimize leaks and enhance pipeline safety: Leak investigations, replacement of cast iron and bare steel, excavation damage prevention;

- An example of an operator’s leak investigation procedure;

- Lost and unaccounted for gas (LAUF): For natural gas utilities and regulators, LAUF is an accounting and ratemaking issue, not an operational issue. EPA has rejected the

[38] See, e.g., ”Protecting our Infrastructure of Pipelines and Enhancing Safety (PIPES Act) of 2020”, Division R, SEC. 206. PIPELINE SAFETY PRACTICES, Page 2721).

idea that unaccounted for gas could provide an indication of fugitive methane emissions;

- How environmental conditions impact leak detection; and

- EPA's emission factors and the need for EPA to update these emission factors to help provide all interested stakeholders with more accurate data.

B. Support of PHMSA's June 2021 Advisory Bulletin and February 2022 Webinar

On June 10, 2021, PHMSA published an advisory bulletin, "Pipeline Safety: Statutory Mandate to Update Inspection and Maintenance Plans To Address Eliminating Hazardous Leaks and Minimizing Releases of Natural Gas From Pipeline Facilities"[39]. The advisory bulletin stated, PHMSA issued this advisory bulletin "to remind each owner and operator of a pipeline facility that the ''Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020'' (PIPES Act of 2020) contains a self-executing mandate requiring operators to update their inspection and maintenance plans to address eliminating hazardous leaks and minimizing releases of natural gas (including intentional venting during normal operations) from their pipeline facilities. Operators must also revise their plans to address the replacement or remediation of pipeline facilities that are known to leak based on their material, design, or past operating and maintenance history. The statute requires pipeline operators to complete these updates by December 27, 2021." The Associations broadly distributed the advisory bulletin to our members and highlighted the bulletin in meetings with our members.

On February 17, 2022, PHMSA held a webinar "Addressing Inspection of Operators' Plans to Eliminate Hazardous Leaks, Minimize Releases of Methane & Remediate/Replace Leak-Prone Pipe." As stated in the Federal Register Notice[40], the webinar addressed the following topics: "(1) Key elements of Section 114; (2) Significant sources of natural gas (primarily methane) emissions from pipelines; (3) Discussion of which types of pipeline facilities must comply with each portion of Section 114; (4) PHMSA and state inspections, including reviews of a pipeline operator's programs and procedures to reduce methane emissions; (5) Inspection topics related to methane reduction and leak-prone pipes; (6) General review of how operators' programs and procedures will be inspected; and (7) The timelines for actions required by Section 114." The Associations promoted the webinar to our members and encouraged our members to participate in the event.

During the webinar, several of the questions shared by PHMSA for its inspection of operator plans were beyond the scope of the self-executing provisions within Section 114 or the PIPES Act of 2020. The questions appeared to be for data gathering purposes and focused on how operators are performing certain practices related to their systems. For example, some of the questions related to compressors; leak collection and data analysis – including leaks that

---

39 https://www.govinfo.gov/content/pkg/FR-2021-06-10/pdf/2021-12155.pdf
40 https://www.regulations.gov/document/PHMSA-2021-0123-0001

operators eliminate by lubrication, tightening and adjustment; repair procedures; lost and unaccounted for gas (LAUF); and a variety of other detailed topics. Section 114 does not outline specific practices that operators are required to implement, but rather requires operators to show how their individual O&M plans help minimize the release of natural gas.

Following the webinar, the Associations submitted comments to the webinar's docket that included:

- Suggestions on how PHMSA could provide clarity between the inspection of an operator's execution of the Section 114 mandate and the separate data gathering efforts;
- A request that PHMSA ensure that new protocols and regulations are not duplicative of existing measures; and
- Information regarding AGA's white paper, "Considerations for Eliminating Hazardous Leaks and Minimizing Releases of Natural Gas" (included as Appendix G). The white paper was created to provide consistency in industry's implementation of the self-executing provisions within Section 114 of the PIPES Act.

V. Corrections to Information Contained in PHMSA's Preamble

In the preamble to the proposed rule, there are numerous assertions, statements, and conclusions that are misleading or incorrect. Given the significant and expansive scope of this proposed rule and the potential impact implementation of this rule will have on regulated entities, natural gas utilities, and the millions of customers they serve, it is imperative that this rulemaking be based on accurate, transparent, and unbiased information. Below are the statements within the preamble that are the most concerning to the Associations:

A. *"Recent research using modern leak detection equipment indicates that overall fugitive emissions from gas pipeline facilities may be significantly underestimated in current methane emissions estimates[41]"*

PHMSA asserts in the preamble that "*[r]ecent research using modern leak detection equipment indicates that overall fugitive emissions from gas pipeline facilities may be significantly underestimated in current methane emissions estimates.*"[42]. The studies PHMSA cites for this alleged significant underestimate are those that use top-down methods that measure concentrations in the air, and that do not compare these measurements with bottom-up equipment and facility measurements in the same timeframe and location. Both a landmark peer-reviewed study and a National Academies of Science (NAS) report explain that the perceived gap between top-down studies and inventories based on bottom-up measurements and emission factors is largely explained by the temporal and spatial differences in the two types of measurements. They concluded

[41] 88 Fed. Reg. at 31900.
[42] *Id*.

that the way to reconcile the two approaches is to conduct both at the same time and place.

The Associations recommend that PHMSA review the landmark, peer-reviewed Fayetteville Basin Methane Reconciliation Study[43] which found that the difference between the top-down and bottom-up methane measurements could be largely explained by the different time and spatial scale of the measurements. The study generated eight peer-reviewed scientific journal articles, culminating in the capstone paper: "*Temporal Variability largely Explains Difference in Top-down and Bottom- up Estimates of Methane Emissions from a Natural Gas Production Region*" published in the Proceedings of the National Academy of Sciences (PNAS) on October 29, 2018,[44] that demonstrated how the study successfully provided the first temporally- and spatially-aligned top-down and bottom-up methane emission estimates for a shale gas production basin in the United States. The study reconciled top-down aircraft measurements with facility and equipment level bottom-up measurements on basin, site, and component scales – by aligning them in the same time frame and place.

The Fayetteville Basin Reconciliation Study's key findings, insights, and implications for industry practice and future studies are described in layman's terms in a short Summary Paper provided on the study's website[45]. The key findings were as follows:

1. *"While both top-down and bottom-up measurements are equally valid approaches to estimate methane emissions on a regional scale, this study illustrates that the measurements must be carefully aligned in both time and space to be compared. This alignment requires adjustments to measurement protocols – namely requiring near- simultaneous measurements at all scales – and also requires access to highly-resolved operational data on the timing and location of emissions during the study period. As such, this study showed excellent agreement between these two approaches to methane emission quantification, without requiring guesswork or statistical assumptions that have been used to close the gap in prior research."*

   "The key source that explained the difference between top-down and bottom-up estimates in the Fayetteville play are manual well-clearing activities (called "liquids unloading" by industry, where "manual" refers to operator initiation and supervision). Emissions from these sources systematically occur during daytime operator shifts,

[43] See Colorado State University Energy Institute website for links to the summary paper and a series of methodology papers as well as an explanatory video, Fayetteville Study: Basin Reconciliation - Energy Institute (colostate.edu), https://energy.colostat.edu/metec/fayetteville-study-basin-reconcilitation/

[44] Vaughn, TL, Bell, CS, Pickering, CK, Schwietzke, S, Heath, GA, Pétron, G, Zimmerle, DJ, Schnell, RC, Nummedal, D (2018) Temporal variability largely explains top-down/bottom-up difference in methane emission estimates from a natural gas production region. Proc Natl Acad Sci USA 115: 11712-1717. Temporal variability largely explains top-down/bottom-up difference in methane emission estimates from a natural gas production region| PNAS, https://www.pnas.org/doi/10.1073/pnas.1805687115.

[45] See BasinMethaneOverview.pdf (colostate.edu), https://energy.colostate.edu/wp-content/uploads/sites/28/2021/03/BasinMethaneOverview.pdf

which is also when meteorological conditions are ideal for basin-scale aircraft methane emission measurements. Bottom-up inventories that follow the standard practices of representing averages of daily, monthly or annual periods do not capture the diurnal coincidence of aircraft top-down measurements during peak emission periods. Collecting information about where and when liquids unloadings occurred during the study was critical to ensuring accurate bottoms-up emissions modeling and for proper temporal and spatial alignment for comparison with the top-down aircraft measurements."

2. *"The study for the first time deployed multiple measurement methods in a systematically designed method intercomparison framework to provide guidance on the accuracy and use cases for each. The study found systematic trends for three methods designed to quantify site-level methane emissions: two ground-level, downwind methods, one of which required site access to release a tracer gas at a known release rate which is measured along with methane downwind of the site ("tracer") and another only measuring methane downwind of the site ("OTM33A"); the third site-level method sums emissions measured at the equipment and activities existing within a site ("onsite")."*

    a. *"At production sites (well pads), on average, the downwind OTM33A method estimates lower (and is less accurate) than onsite estimates while the tracer method estimates higher than both. Based on the tests performed in this study, OTM33A can be best deployed to discern "large" and "small" emissions. The study also found a similar systematic estimation trend for compression stations (in the gathering segment of the natural gas value chain) where tracer method estimates slightly lower than onsite estimates."*

    b. *"While these first-of-kind, site-level comparisons provide high confidence that both onsite and downwind methods can do an adequate job of capturing total site emissions, the methods have different use cases and more method intercomparison is needed to discern when each can be most accurately deployed, considering the desired level of accuracy required of the measurement."*

3. *"When focused on science, strong safeguards for integrity coupled with robust and regular knowledge sharing between researchers, industry and government can lead to unprecedented advances in understanding of the role of industrial practices in GHG emissions. This in turn provides industry opportunity to improve profitability and sustainability from reducing the loss of natural gas through controllable emissions."*

4. *"Operator direct participation in field studies, including providing physical access to sites as well as sharing data on location, count, timing, duration and strength of emissions sources is critical to the development of high-resolution spatio-temporal inventories of methane emissions. We were able to achieve kilometer-scale, hourly-*

resolution inventories based on contemporaneous measurements, yet note that an even higher temporal resolution could further improve top-down and bottom-up alignment (e.g., to better understand sources whose emission rate can vary significantly within an hour).”

Nevertheless, the resolution achieved in this study improved the identification of specific large emission sources.”[46]

A National Academies of Science (NAS) consensus report in 2018 recommended using the methodology used in the Fayetteville Basin Reconciliation Study for other studies seeking to reconcile top-down and bottom-up methane measurements.[47] Specifically, the NAS report recommended working with operators to obtain site access for bottom-up facility and equipment measurements and to align those measurements in time and space with top-down measurements.

The studies PHMSA cites in the preamble to the proposed rule do not follow this best practice for reconciling top-down with bottom-up measurements. As a result, they do not provide a rational basis for assertions about national emissions being “significantly” larger than EPA’s Greenhouse Gas Inventory (GHGI) estimates or for justifying rule revisions to require gas utilities to eliminate all detectable leaks, even “fizz” leaks that are barely detectible, can be measured in terms of “bubbles per minute,” and neither pose a safety risk nor contribute appreciably to methane emissions.

The Associations also note that because EPA’s Subpart W methane emission factors under the current GHG Reporting Rule are still based on the much older 1996 GRI-EPA Study rather than the updated 2015 Lamb Study emission factors used in the GHGI for distribution systems, individual gas utilities are limited in their ability to use that reported data to fully demonstrate the significant progress they have made in lowering emissions[48]. More fundamentally, the current reporting approach limits the ability of a company to provide a more accurate report of company emissions, because in most cases Subpart W currently requires a company to multiply national average emission factors by miles of pipe or equipment numbers. Even if a company reduces its real emissions, that information will not show up in the reported numbers. In fact, if a company installs new pipelines, the reported numbers may appear to increase even if the company’s practices result in actual real-life reductions. In joint comments to EPA, AGA and APGA urged EPA to allow an option for companies to report emissions based on

[46] See BasinMethaneOverview.pdf (colostate.edu), https://energy.colostate.edu/wp-content/uploads/sites/28/2021/03/BasinMethaneOverview.pdf (Key Findings).
[47] National Academies of Sciences, Engineering & Medicine, *Anthropogenic Methane Emissions in the United States: Improving Measurement, Monitoring, Reporting, and Development of Inventories* (April 2018), p. 138, available at Anthropogenic Methane Emissions in the United States Improving Measurement Monitoring Reporting and Development of Inventories | National Academies. Link: https://www.nationalacademies.org/our-work/anthropogenic-methane-emissions-in-the-united-states-improving-measurement-monitoring-reporting-and-development-of-inventories.
[48] *See* 40 C.F.R. §§98.230 – 98.238.

company-specific measurements and company-specific emission factors multiplied by a leak count activity factor. This would reward and incentivize cost-effective methane emission reductions and improve the accuracy of overall methane emission estimates for individual companies and the nation. The Associations would welcome PHMSA's support for this approach in the interagency review of EPA's upcoming revisions to 40 C.F.R. Part 98, Subpart W.[49]

B. "For example, recent analysis using top-down methods from the IEA released in early 2022 found that global methane emissions from the energy sector are about 70% greater than the official statistics reported by national governments." (p. 31900 of the NOPR).

PHMSA has incorrectly used the International Energy Agency Global Methane Tracker to assert that current estimates of methane emissions are underestimated. The methodology employed by the IEA Global Methane Tracker renders it incapable of providing evidence supporting claims of underestimation or overestimation of methane emissions derived from natural gas systems, inclusive of transmission and distribution pipelines.

Methane emission data from the U.S. is used as the initial benchmark for the IEA's estimates of country-level methane emissions. The IEA Global Methane Tracker generates comprehensive estimates of methane emissions from all forms of human activity, including coal, oil, and natural gas production or use. The IEA employs a methodology wherein the upstream and downstream oil and gas emissions intensities in the U.S. are used as the starting point. These emissions intensities are then indexed as "1" and are proportionately adjusted to generate emissions intensities for other countries. As a result, it's not feasible for the IEA's U.S. estimates to be deemed as overestimated or underestimated using this data source since U.S. government estimates form the foundation to their overall analytical framework.

PHMSA incorrectly indicates that top-down approaches are superior to bottom-up (component or facility-level measurements or estimates) development of methane inventories. There are limitations to both component measurement and quantification from a top-down approach (measurements taken at spatial scales greater than the component). Moreover, temporal variability may explain the difference between top-down and bottom-up differences in methane emissions estimates[50]. Methods employing a combination of approaches that could be characterized as bottom-up <u>and</u> top-down are necessary to measure and report total emissions associated with natural gas systems accurately.

It should also be noted that claims related to natural gas system methane emissions underestimation can only be applied in aggregate and do not necessarily apply to

[49] August 1, 2023; 88 Fed. Reg. 50282
[50] https://www.pnas.org/doi/10.1073/pnas.1805687115

individual facilities. The methane emissions from an individual facility can be higher or lower than inventory estimates[51].

C. Methane Emissions from Gas Distribution Are Not Significantly Higher than the 0.1 Percent Rate Shown in the 2023 EPA GHGI

1) ***The Weller Study Does Not Provide a Reasonable Basis for Evaluating Methane Emissions from Gas Distribution Mains by Material, Particularly for Protected and Unprotected Steel Mains***

In the preamble to its proposed rule, PHMSA repeatedly cites to a 2020 study by Weller *et al* (the Weller Study) to advance the assertion that methane emissions from natural gas distribution are significantly higher than the 0.1 percent reported in the 2023 EPA GHGRI.[52] [53] However, this reliance is not justified. Due to several shortcomings, the Weller Study yields results that are significantly inconsistent with all other previous studies and should not be used to support rulemaking decisions. In particular, the Weller Study's estimated emissions from distribution mains are wildly skewed by errors made in its evaluation of protected and unprotected steel mains as well as limitations on the use of top-down measurements that are not paired in time and place with bottom-up facility and equipment measurements together with operational information.

The most glaring problem with the Weller Study is the authors' misidentification and misunderstanding the categories of protected and unprotected steel pipe as defined under 49 C.F.R. §§192.455, 192.457, and 192.479 and how gas distribution companies annually report their mileage of distribution pipe by material and level of protection to PHMSA under 49 C.F.R. §191.11 on DOT Form PHMSA F 7100.1-1 (Annual Distribution Report)[54]. The reports are due by March 15 each year and cover data for the previous year. Part B of the Annual Distribution Report, titled "System Description," requires a gas distribution utility to report miles of main and number of services in the system at the end of the previous year by material type. For steel mains and services, Part B requires a distribution utility to report whether the steel pipe is "unprotected" or "cathodically protected" – clearly indicating that steel pipe that is not cathodically protected – even if coated – is considered to be unprotected steel.

---

[51] https://pubs.acs.org/doi/10.1021/acs.est.2c06211
[52] 88 Fed. Reg. at 31901.
[53] 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, Correction published *Environ. Sci. Technol.* 2021, 55, 1, 806 (correcting estimated total number of leaks from pipeline mains in text to match value in Table 2), Publication Date: December 17, 2020 (hereinafter, Weller Study).
[54] The version of DOT Form PHMSA F 7100.1-1 that was used for annual distribution mileage reports through 2020, and thus would provide the mileage data relevant to the time period examined in the Weller Study , is available on the DOT PHMSA website under https://www.phmsa.dot.gov/forms at: ANNUAL REPORT FOR CALENDAR YR (dot.gov). While some portions of the Annual Distribution Report were revised in the version used in 2021 and later, Part B has remained unchanged.

The Weller Study did not make this important distinction between cathodic protection and the lack of cathodic protection. As a result, the authors included leak measurements on unprotected coated steel in their category of protected steel. As a result, they calculated a very inflated emissions leak rate for what they (wrongly) assumed came from "protected" steel. This led them to conclude – illogically – that protected steel leaks more than unprotected steel. In fact, the opposite is true.

It is well-known from previous studies and operator experience that cathodically unprotected buried steel pipe has more leak emissions than modern cathodically protected steel. Both the 1996 GRI-EPA study[55] and 2015 EDF Lamb *et al.* Study (Lamb Study) clearly demonstrate this emissions differential. EPA has recognized this well-known fact as well. EPA's voluntary Methane Challenge program incentivizes natural gas distribution companies or municipal utilities to replace cathodically unprotected steel pipe with cathodically protected steel pipe.

In EPA's June 2022 Notice of Proposed Rulemaking to revise the GHG Reporting Rules in 40 C.F.R. Part 98, EPA sought comment on whether to revise the methane emission factors local distribution companies use to calculate and report their methane emissions from distribution mains based on a blend of the Weller Study and the Lamb Study. EPA contended that 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.

AGA and APGA explained in our October 2022 comments why EPA should reject this approach. For the same reasons, we urge PHMSA not to rely on the Weller Study in this rulemaking. While the Weller study may have a larger sample size, numerous limitations preclude it from being used as an accurate basis for assessing methane leak rates from gas distribution pipelines or to justify the proposed revisions to the default emission factors for distribution mains. Simply stated, the Weller Study is not a reasonable basis for rulemaking for the following reasons:

- First, and most importantly, the Weller Study conflated cathodically unprotected coated steel in the "coated (protected)" steel emission factor Category and did not verify the pipeline type, material, or cathodic protection. The Weller Study authors did not obtain information about or verify whether the pipe was cathodically protected. As a result, no distinction between cathodically protected and unprotected steel pipelines 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

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

large part of the answer to why the findings in the Weller Study are counterintuitive - and counter-factual.

Steel pipelines can be protected through cathodic protection and/or coating. Natural gas distribution pipeline operators annually report miles of steel pipeline to the DOT PHMSA in four categories: cathodically protected coated pipe, cathodically protected uncoated pipe (the two types of “protected steel”), coated steel pipe that is not cathodically protected and bare steel that is not cathodically protected (the two types of “unprotected steel”).

The Weller Study also did not verify the type of pipeline – distribution main or service line. The authors conceded they assumed all emissions to be caused by distribution 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…”* [56]

As a result, distribution 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[57]. 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 PA 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[58].“*

The methodology of the CARB-GTI Study included an advanced statistical and probabilistic analysis on the leak data and the misclassifications to provide a

---

[56] Weller Study, Section 2.2, p. 8960.
[57] Ersoy, Adamo, “Quantifying Methane Emissions from Distribution Pipelines in California,” Final Report (Sept. 2019) (“CARB-GTI Study”).
[58] *Id*. p. 1. *See* also p. 13 and Appendix A.

representation of the average leak rates for underground distribution mains and services by pipe type, material, and protection[59].

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. A bare steel pipe is a pipe that lacks a coating – 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 pipelines.

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 and emission estimates for protected and unprotected steel pipe.

- Second, although the “advanced mobile detection platform” (AMLD) methodology used in the Weller Study shows great promise for the development of system-specific emission factors, 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. Additionally, AMLD can also be quite useful to quantify overall emissions from 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, AMLD, as currently available, 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 CH_4 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-

[59] *Id.*, at p. 1.

hazardous leaks that are relatively higher emitters[60]. Under DOT PHMSA pipeline safety regulations, 49 C.F.R. Part 192, natural gas 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, 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[61] – one of which was used in the Weller Study – coupled with modeling) with direct measurements of over 300 leaks using a high-volume sampler[62]. 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."[63] 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."[64] Stated simply, the NYSEARCH Study demonstrates that the

---

[60] 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 (1990-2021) published in April 2023 indicates that emissions from gas distribution in the U.S. contributed only 8.5 % of emissions from the natural gas sector. *See* AGA's analysis in "Understanding the EPA GHG Inventory," p. 13,Understanding Greenhouse Gas Emissions From Natural Gas - EPA 2023 Inventory (1990-2021) - American Gas Association (aga.org), enclosed as Appendix H.

[61] 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

[62] https://www.nysearch.org/white-papers/Validation-Methods-for-Methane-Emissions-Quantification-Technologies-Final.pdf (Oct. 2020) (hereinafter NYSEARCH Study).

[63] *Id*. p. 2.

[64] NYSEARCH Study, p. 1 referencing Figure 1.

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

While AMLD is not the best tool for developing population- based emission factors for different types of pipelines, the NYSEARCH Study noted that a previous report indicated that with repeated passes, mobile technologies such as AMLD 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*."[65]

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, sewers, and other biogenic sources rather than only leaks from the natural gas distribution systems, thereby inflating emissions and leak rates[66].

---

[65] *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.

[66] *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

- 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 (about 130 feet) 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 basis 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. In fact, EPA explicitly acknowledges the challenges and shortcomings associated with using the Weller study to establish national emissions factors in its recently released proposed rule, "*Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems*[67]*.*" In that proposed rule, EPA reached the following conclusion:

> *In the 2022 Proposed Rule, we proposed to revise the pipeline main equipment leak emission factors using a combination of data from Lamb et al. (2015) and Weller et al. (2020). We sought comment on the approach of combining data from these two studies. We received numerous comments regarding the classification of pipeline materials and respective quantified leaks in the Weller et al. (2020) study. In response to these comments and as discussed in more detail below, we agree with commenters that the categorization of pipeline leaks by material type likely resulted in inaccuracies specifically for the unprotected and protected steel pipeline material types. In this rulemaking, we are continuing to propose revisions of the equipment leak pipeline main emission factors using more recent study data, but instead of combining data from Lamb et al. (2015) and Weller et al. (2020), we are proposing to rely only on the Lamb et al. (2015) study*[68].

Similarly, PHMSA should base its proposed rule on the best available evidence. For the reasons described in detail above, PHMSA's reliance on the findings in the Weller

4.2 of the 2019 Weller et al. study, which states in paragraph 4 of section 4.2: "First, we do not distinguish between thermogenic and biogenic CH4 sources, but this capability could be added by analyzing both CH4 and ethane concentrations. There is no reference to using methane to ethane ratios in the Weller Study published in 2020.

[67] 88 Fed. Reg. 50282 (Aug. 1, 2023).

[68] *Id.* At 50352.

Study is misplaced. As discussed in detail below, the Lamb Study provides a more accurate assessment of methane emissions from the gas distributions sector.

2) ***The Lamb Study and EPA GHGI Provide a More Accurate Assessment of National Methane Emissions from Gas Distribution***

EPA currently uses the Lamb Study emission factors in its annual GHGI, and this is appropriate because the Lamb Study provides the best basis available at present for national average emission factors.

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.

In addition, 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.

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.

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. The failure to distinguish between cathodically-protected and cathodically unprotected steel pipe and the failure to verify other types of pipe material or locate leaks on services vs. mains were all key weaknesses of the Weller Study.

For the foregoing reasons, PHMSA should not use the Weller Study to support its assertion of alleged higher emissions from gas distribution mains or to justify a mandate to fix all leaks, even those that pose no safety hazard and are very low emitting. PHMSA should use the EPA GHGI estimates for evaluating nationwide emissions from gas distribution and for assessing appropriate regulatory changes.

D. "Pipeline operator leak detection and repair practices are similarly insufficient to meet the risks to the environment and public safety from leaks of methane and other gases from gas pipeline infrastructure.[69]*"*

The Associations strongly disagree with PHMSA's assertions in the preamble that "*pipeline operator leak detection and repair practices are … insufficient to meet the risks to the environment and public safety from leaks of methane*" and that voluntary methane reduction initiatives "*exhibit shortcomings*" such as "*meager participation,*" "*absence of meaningful leak reduction target*s[70]" or lack transparency. As noted previously, the Associations and our members have robustly participated in the programs such as EPA Gas STAR and Methane Challenge programs to reduce methane emissions, have developed leading practices to reduce methane emissions, have invested in R&D to develop best practices and invested in new technologies for methane detection and emissions reduction[71]. Each Association, and many of our members, has publicly committed to reducing GHG emissions, even setting net-zero methane emissions goals. EPA's programs are transparent, and the list of participants appears on EPA's website. For EPA's updated Methane Challenge initiative, each company's leak reduction goals and achievement of the goals are also transparently posted on the website. Additionally, many of the Associations members have published their specific emission reduction activities and goals on their websites and in company specific climate and ESG reports.

PHMSA notes there are still 18,314 miles of cast or wrought iron distribution mains in the ground based on the 2021 reports. This represents a reduction of 39,978 miles of main since 1990.

PHMSA's own Natural Gas Distribution Infrastructure Safety & Modernization (NGDISM) grant program for publicly and community owned natural gas systems will greatly reduce the mileage of pipelines in operation that are most prone to leakage. In the Tier 1 environmental assessment, PHMSA estimates 1,000 miles of pipe will be replaced during the five-year program. This equates to a reduction of 4,166,930 kg of methane emissions over 20 years. While there is more work to be done, gas utilities are continuing to reduce this mileage, working within the parameters set by their rate setters, such as state public utility commissions, utility boards, and city councils, and balancing the need to maintain affordable energy costs for customers.

[69] 88 Fed. Reg. at 31919
[70] *Id*.
[71] E.g., Operations Technology Development (OTD) Research Project Summaries 2020: https://www.otd.org/wp-content/uploads/2021/10/OTD-Research-Project-Summaries-2020.pdf; Pipeline Research Council International Years in Review: https://www.prci.org/About/YearsinReview.aspx; Northeast Gas Association NYSEARCH 2021 Annual Report: https://www.nysearch.org/tech-brief-pdfs/2NYSearchBookUPDATEDFINALWEBFILE.pdf

The Associations members have also been leaders in developing, testing, and deploying new methane leak detection and quantification technologies such as AMLD. While AMLD is currently not the best tool for quantifying emission flow rates from individual sources, as discussed above, there continue to be technological developments with the promise of accurate quantification of collective methane emissions across all natural gas 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 supported by a robust, statistically valid sample of direct measurement data. Presently, this is costly and sophisticated compared with the traditional leak detection and emission factor methods, but more companies are beginning to experiment with these new technologies and business practices. As the industry gains additional experience and more utilities participate and share experiences with industry peers, and economies of scale drive down price, this method should become more accessible to smaller gas operators.

Demonstration projects using AMLD are already occurring in the field by Association members such as 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 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 which were then confirmed in subsequent surveys. A copy of the Atmospheric Environment: X study,[72] is attached as Appendix I. It should be noted that there are various AMLD technologies and vendors offering an array of products including drones, satellite technologies, mobile cavity-ring down mass spectrometers or mobile laser spectroscopy technologies, coupled with sophisticated modeling and the ability to differentiate biogenic sources of methane[73].

In addition, GTI Energy is working with companies across the natural gas value chain, academics, and NGOs in its Veritas initiative to build 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

---

[72] MacMullin & Rongère, "Measurement-based emissions assessment and reduction through accelerated detection and repair of large leaks in a gas distribution network", *Atmospheric Environment: X* (Jan. 2023), https://www.sciencedirect.com/science/article/pii/S2590162123000011

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

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

quantification methodology[74]. GTI Energy recently released the Veritas segment specific protocols and is working with AGA members and others in the natural gas value chain to road test and improve the protocols.

In sum, contrary to PHMSA's assertion in the preamble, the industry continues to demonstrate its seriousness to address methane leaks and remediation by incorporating methane leak detection and repair practices and efforts that are robust and forward-looking, and adaptable to rapidly occurring technological advances.

E. Additional Errors Identified in the Preamble to the Proposed Rule

In addition to the above, the Associations also identified the following errors:[75]

- Citation 12 states, "The IPCC also noted that in 2019, atmospheric CH4 concentrations were higher than at any time in 800,000 years, and that "strong, rapid and sustained reductions in CH4 emissions" would be needed to offset short-term warming effects. - The page and figure referenced do not exist.

- Citation 23 and 24, references IPCC Report, SPM-24 and SPM-23. This citation should be to SPM page 18.

- Citation 31 states, "Similarly, scientists have observed that it is likely that hurricanes have become stronger and more intense and determined that it is likely that anthropogenic climate change has increased rainfall rates associated with hurricanes and other tropical cyclones." However, the 2021 IPCC Report, SPM-9 does not discuss hurricanes.

- Citation 41 states, "While projections are difficult to make for infrequent, smaller weather events like tornadoes and severe thunderstorms, these events have also been recently exhibiting changes that may be caused by climate change." However, the report, *U.S. Global Change Research Program, Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Our Changing Climate at 97 (2018)* specifically notes uncertainty regarding this statement: "Other

---

[74] *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.

[75] The Associations believe there are likely far more issues in the preamble to the proposed rule than those identified in these comments. However, given the insufficient time – 90 days - to respond to one of the most substantive and technically complex rulemakings PHMSA has ever released, we are unable to assemble a complete and comprehensive list here.

types of extreme weather, such as tornadoes, hail, and thunderstorms, are also exhibiting changes that may be related to climate change, but scientific understanding is not yet detailed enough to confidently project the direction and magnitude of future change." (Emphasis added)

- Citation 43 states, "The 4th National Climate Assessment identifies an average of 2 to 4.5 feet as the most probable sea level rise in the Northeast United States before 2100 with worst-case estimates projecting sea level rise of more than 11 feet over the same period." - The statement is missing context. The NCA actually states, "The worst-case and lowest-probability scenarios, however, project that sea levels in the region would rise upwards of 11 feet (3 m) on average by the end of the century." (Emphasis added)

- Citation 48 states, "According to the 2016 assessment of human health impacts of climate change from the U.S. Global Change Research Program (2016 Assessment), climate change will likely contribute to ''thousands to tens of thousands of premature heat-related deaths in the summer'' in the United States in the years ahead." - This is an inaccurate statement based on the citation. The source states: "For example, by the end of the century, reduced climate change under a lower scenario (RCP4.5) compared to a higher one (RCP8.5) avoids (on net, and absent additional risk reduction through adaptation) thousands to tens of thousands of deaths per year from extreme temperatures…".

VI. Excavation Damage Continues to be a Leading Cause of Leaks and Methane Emissions Attributed to the Natural Gas Industry

Excavation damage continues to be a significant cause of natural gas and hazardous liquid pipeline leaks. PHMSA's 2022 incident data shows the amount of methane released from distribution systems due to excavation incidents is nearly as much as all other distribution incidents combined (53,879 Mscf vs. 63,212 Mscf). Excavation damage also resulted in 78,756 Mscf released from gas transmission systems and 2,543 barrels spilled from hazardous liquid pipelines.

PHMSA's 2022 annual report indicates that excavation damage is the primary cause of hazardous leaks on both distribution mains and service lines. There were 17,120 hazardous leaks on distribution mains and 65,107 hazardous leaks on distribution services in 2022 alone. For natural gas transmission systems, PHMSA's 2022 annual report data indicates there were 29 leaks due to excavation damage, and 1 leak and 6 failures due to previous damage caused by excavation activity. For gas gathering lines, PHMSA 2022 annual report data indicates there were 11 leaks due to excavation damage and 6 failures due to previous damage caused by excavation activity.

According to the Common Ground Alliance's 2021 DIRT Report[76], failure to notify the 811 center "remains the top root cause with over a quarter of all damages still attributed to no notification.

[76] See https://dirt.commongroundalliance.com/

CGA excavator research tells us that professional excavator awareness of 811 is very high[77], yet 60% of all damages due to no notification can be attributed to professional excavators. It is important to note that 36% of those professional excavators failing to contact 811 were likely working on projects associated with utilities (natural gas, electric, telecommunications) and/or municipalities (water, sewer, road, sidewalks, etc.)[78].

Operators need help from state authorities, including their active enforcement of existing One Call laws on excavators who fail to notify 811 or fail to comply with excavation damage prevention laws, and their active participation with other interested stakeholders to improve One Call laws in their respective states and implement safer excavation practices, including hand-digging around underground utilities. State authorities should also be encouraged to examine existing One Call laws and identify potential enhancements to strengthen such laws. While enforcement oversight exists for natural gas operators, increased enforcement of state One Call laws for other entities and parties will not only increase public safety but also will have the effect of decreasing damage that causes leaks from pipelines.

PHMSA also has a critical role to play in reducing excavation damage occurring on our nation's pipelines. It can continue to take enforcement action and impose penalties against persons who violate a state's damage prevention laws where the Secretary has determined the State's enforcement is inadequate to protect safety. In its grants to states, PHMSA can require the State's adoption of one-call leading practices with targeted funding to advance technology that will improve the effectiveness of the One Call process. And PHMSA can modify its criteria for determining the effectiveness of State programs, to include if the state has:

- Effective, active, meaningful enforcement of state dig laws (including efficacy of fines and penalties); and

- Reporting requirements to the local One Call Center for excavation damage incidents on pipelines and other underground facilities that are not privately owned to include (as is available at the time of the reporting):

    - Information about the nature of the incident;
    - Entities involved (telecom, construction, etc.);
    - Economic, health, safety and (in the case of gas distribution utilities) customer service impacts; and
    - Impact to environment

PHMSA and state efforts to reduce excavation damage will result in a reduction in serious and significant pipeline incidents, a reduction of deaths and injuries due to excavation incidents, a reduction in property damage due to excavation incidents, and a significant reduction in methane emissions.

---

[77] 84% of professional excavators are aware of 811, according to [CGA's 2019 national excavator survey]().
[78] 2021 DIRT Report, page 4.

A. *Industry Requires Multiple Leak Detection Sensitivity Standards*

Remote sensing techniques, many of which detect flux (kg/hr emissions rate) do not directly measure concentration, have significant benefits in the gas gathering and transmission pipeline leak detection space. The speed and scale at which remote sensing technologies operate can deliver highly effective leak detection programs at a significant cost and time savings over ground-based or handheld methods. A 5-ppm concentration may be suitable as a blanket standard for other segments of the pipeline industry for which ground-based or handheld methods are fit-for-purpose, but when applied to gas gathering and transmission lines this standard would limit technology flexibility and availability, and would not effectively identify emissions in the most cost-effective manner. The record does not include a credible technical basis for a 5-ppm concentration threshold. The rulemaking docket contains vendor promotional materials and records of vendor meetings with PHMSA where vendors made claims about the capabilities of their equipment, but there is no documentation to indicate that PHMSA has tested or otherwise verified these claims. The docket does include a "Technical Report" by Highwood Emissions Management, PHMSA-2021-0039-0011, purporting to provide a literary review of methane detection equipment. However, nothing in that report discusses detection limitations for any particular type of technology, much less provides support for creating an unprecedented 5-ppm leak definition.

Even if PHMSA were able to develop record evidence discussing methane detection equipment with a ppm detection limit, PHMSA should still consider other factors such as the reliability of the equipment in field conditions, practicality of using equipment to measure across a pipeline at that level, and the cost-effectiveness criteria commonly considered by EPA in establishing leak detection and repair regulations. Under OOOOa, fugitive emissions are defined as, "…as any visible emission from a fugitive emissions component observed using…an instrument reading of 500 parts per million (ppm) or greater..." Under EPA's standard, fugitive emissions/leaks are not considered present if the Method 21 survey detects a volatile organic compound (VOC) concentration under 500ppm, a detection threshold nearly two orders of magnitude larger than PHMSA's proposed standard. In establishing leak definitions for its own regulations, EPA has relied on cost effectiveness evaluations, examinations of leak definitions under similar state and federal statutes, experience with various leak definitions required by consent decrees, and the ability to repair detected leaks, among other factors. PHMSA, like EPA, should perform a holistic analysis that considers factors relevant to reliably and practicably detecting and repairing leaks before defining this threshold for a "leak."

The undersigned recommend that PHMSA review and consider both the tiered matrix methane emissions monitoring approach in Table 1 of the Environmental Protection Agency's (EPA) proposed rulemaking for Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources (OOOOb) (EPA-HQ-OAR-2021-0317). The proposed technology-neutral, performance-based approach under OOOOb determines the equivalency of a given alternative detection method in an emissions rate-based framework (kg/hr) with the long-established Best System of Emissions Reduction (BSER) for upstream production facilities of quarterly surveys using Optical Gas Imaging (OGI) to identify fugitive emissions. In such a tiered approach, an alternative detection technology such as airborne or satellite-based remote sensing monitors on a frequency commensurate with the rate-based detection sensitivity of the technology to detect emissions. This allows greater spatial coverage and faster response, as well as improved personnel safety by requiring fewer man-hours spent on-site conducting ground-based or handheld surveys.

While a promising first step, EPA's proposed matrix is subject to change in the final rule and should be informed by a OGI efficacy value that more closely resembles real-world conditions and an emissions distribution that captures the full range of emissions to achieve BSER. This work points to the need for a robust understanding of the emissions distribution of the given sources and the importance of appropriately modeling an alternative detection framework against an established standard such as EPA's BSER for fugitive emissions monitoring."

PHMSA should also consider adopting EPA's proposed approach to approving alternative detection technologies at 40 CFR §60.5398b(d). Under this approach, EPA has proposed to "future proof" the rule by allowing new technologies to be approved upon demonstration that the detection technology and method satisfy the requisite "tier" of the proposed alternative detection technology survey matrix. PHMSA could build on this concept by creating two pathways for technology approval- one for concentration-based detection methods, and another for rate-based. Operators could then have the option to select the best fit-for-purpose detection method that meets the appropriate standard.

VII. Certain Aspects of PHMSA's Proposed Rule are Inconsistent with Congress' Intent, the Pipeline Safety Act, the Administrative Procedures Act, and U.S. Supreme Court Precedent.

A. PHMSA is exceeding the clear intent of Congress and in its implementation of Section 113 of the PIPES Act of 2020

As discussed above, Section 113 of the PIPES Act requires operators of regulated non-rural gas gathering lines, new and existing gas transmission pipeline facilities, and new and existing gas distribution pipeline facilities, to conduct leak detection and repair programs that meet the need for gas pipeline safety and protect the environment. In the requirements for the leak detection and repair programs, Congress was explicitly clear in its mandate: that leak detection programs should focus on the ability to "identify, locate, and categorize all leaks that – (i) are <u>hazardous</u> [emphasis added] to human safety or the environment; or (ii) have the potential to become explosive or otherwise hazardous to human safety." Section 113 also requires operators to use advanced leak detection technologies and practices and "include a schedule for repairing or replacing each leaking pipe, <u>except a pipe with a leak so small that it poses no potential hazard</u> [emphasis added], with appropriate deadlines. Congress made it clear that not all leaks were to be deemed hazardous and not all leaks should be required to be repaired. However, PHMSA's proposed definitions of "leak" and "hazardous leak" result in an expansive regulatory regime that, contrary to Congress' clear intent, would require operators to identify and repair all leaks – regardless of the risk the leaks pose to public safety or the environment. This expansive approach effectively removes the word "hazardous" from the statutory text, is inconsistent with both the plain language of Section 113 and Congress' clear intent and is contrary to recent Supreme Court precedent.

As the United States Supreme Court has repeatedly held, "it is a fundamental canon of statutory construction that the words of a statute must be read in their context and with a view to their place in the overall statutory scheme[79]." Where the statute at issue is one that confers authority upon an administrative agency, that inquiry must be shaped, at least in some measure, by whether Congress in fact intended to confer the power the agency has asserted. As the Supreme Court recently affirmed in *West Virginia v. EPA*, "extraordinary grants of regulatory authority are rarely accomplished through "modest words," "vague terms," "or subtle devices." Nor does Congress typically use oblique or elliptical language to empower an agency to make a "radical or fundamental change" to a statutory scheme.[80]

In the proposed rule, PHMSA has interpreted the phrase "hazardous to human safety or the environment[81]" very broadly rather than appropriately associating the more specific terms provided by Congress, "have the potential to become explosive or otherwise hazardous to human safety[82]" and utilizing the already defined "Hazardous Leak" in 192.1001, "a leak that represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous." In enacting this provision, Congress meant to prevent catastrophic and specific incidents of potential human or environmental harm that could result from pipeline leaks, not to grant PHMSA plenipotentiary authority to require extensive operational changes[83]. PHMSA has interpreted Section 113(2)(B) of the PIPES Act of 2020 in a manner sufficient to grant itself broad authority to enact sweeping policy in stark defiance of the plain statutory language and the clear intent of the Congress[84]. In this instance,

---

[79] *See, e.g., Davis v. Michigan Dept. of Treasury*, 49 U.S. 809 (1989); *West Virginia v. EPA* 597 U.S. __, (2022).
[80] *West Virgina v. EPA*, 597 at 5.
[81] Section 113 of the PIPES Act of 2020, PL 114-183.
[82] *Id*.
[83] *Id*.
[84] *See West Virginia v. EPA*, 597 U.S. __ 6,18 (2022) (The Supreme Court held that it was implausible that Congress intended to give the Environmental Protection Agency (EPA) authority to devise carbon emissions caps at a level that would force a nationwide change in power generation. The agency's rule, which granted the EPA the broadest imaginable authority to regulate based on climate change, was invalidated by the Court because the language 'system of emission reduction' is far too vague to grant the authority the EPA was seeking. The Court stated that "extraordinary grants of regulatory authority are rarely accomplished through 'modest word[s],' 'vague terms,' or 'subtle devices'.").

PHMSA has clearly misapplied Section 113 of the PIPES Act of 2020 and is poised to enact burdensome measures on natural gas pipeline operators and natural gas utilities, demonstrating a plain overreach exceeding of PHMSA's statutory authority.

Contrary to the Agency's assertions, the proposed definition of "leak or hazardous leak" represents a significant departure from more than five decades of regulatory precedent and industry practice. PHMSA's regulations have long recognized that not all leaks are hazardous. The Agency acknowledged as much shortly after promulgating the original federal gas pipeline safety regulations, stating the following in an August 1972 letter to a member of Congress: "Which leaks are 'hazardous,' which leaks make a pipeline 'unsafe,' and whether a repair has been done 'promptly,' [under 49 C.F.R. § 192.703] depends upon the nature of the operation and local conditions", and that "[t]he nature and size of the leak, its location, and the danger to the public are among the factors that must be considered by the operator" for purposes of that regulation[85].

The Gas Piping Technology Committee (GPTC) guidance for investigating and classifying leaks has long recognized that principle as well. The GPTC criteria for Grade 2 and Grade 3 leaks both acknowledge that leaks can be non-hazardous at the time of detection, and the Grade 3 criteria acknowledges that a leak can remain non-hazardous into the future. Indeed, Congress even recognized in the text of the rulemaking mandate in Section 113 that a pipe can have "a leak so small that it poses no potential hazard[.][86]" The EPA, the federal agency charged with administering the provisions in the Clean Air Act, likewise shares the view that not all leaks are hazardous to the environment[87]. PHMSA concedes that point in the text of the proposed definition itself, as demonstrated by the Agency's unwillingness to apply the definition to the underground gas storage or transmission and distribution integrity management program requirements. PHMSA's attempt to argue that the proposed definition is nothing more than a clarification flies in the face of these authorities and is entirely unpersuasive. Moreover, there is a stark difference between a "leak" and a "hazardous leak." The adjective modifying the latter term makes it such that the two words cannot be one in the same. On the surface, it does not make sense to use two terms to result in one definition. Besides the obvious shortcoming of this problematic definition related to the fact that leaks are graded, and therefore all leaks cannot be the same, general application of a characterizing modifier before a word inherently makes it such that there is meant to be an intended departure from the original term lacking said descriptor.

Having proposed a definition of "leak or hazardous leak" that departs significantly from well-established regulatory precedent and industry practice, PHMSA cannot evade its

[85] PHMSA Letter of Interpretation to the Honorable William D. Hathaway, PI-72-0109 (Aug. 4, 1972).
[86] 49 U.S.C. § 60102(q)(2)(B)(ii).
[87] EPA has regulated methane emissions from the oil and natural and gas sector since 2016 through its Oil and Gas NSPS regulation. *See* 81 Fed. Reg. 35824 (June 3, 2016). Although EPA's regulatory approach to reducing methane from the oil and natural gas sector has gone through several iterations, including an anticipated final rule that is expected to be released in the near future, at no point has EPA characterized all methane leaks as hazardous leaks.

obligation under the Pipeline Safety Act to conduct a risk assessment for that proposal. As discussed in detail below the Agency must identify the regulatory and non-regulatory options considered in developing the proposed definition, as well as the associated costs and benefits. PHMSA must also provide an explanation of the reasons for selecting the proposed definition and rejecting the other options and identify the technical data or other information that form the basis for the risk assessment information and proposed definition. The Agency failed to include any of the required risk assessment information in the PRIA for the proposed definition of "leak or hazardous leak[88]." As a result, the public and GPAC have been deprived of the opportunity to fully participate in the rulemaking process with respect to that proposal.

B. PHMSA's proposal requiring gathering line operators to participate in NPMS is unnecessary and unsupported.

The Agency's proposal to require gas gathering line operators to participate in NPMS is unnecessary and unsupported. Even if PHMSA had the legal authority to pursue such a proposal, the Proposed Rule does not provide a reasonable basis for requiring gathering line operators to participate in the NPMS. Most gathering line operators already provide appropriate pipeline location information to the authorities responsible for administering state damage prevention programs, and these programs do not generally require information with the level of detail that PHMSA requires for the NPMS program. Imposing an additional burden on gathering line operators to provide geospatial data solely for informational purposes is unreasonable. Additionally, the current database does not enable timely access or usable data. Adding roughly 5x the existing pipeline mileage may degrade the performance of a system which is already over-strained.

Finally, the agency has failed to conduct an adequate cost and benefit assessment in accordance with the Pipeline Safety Act and guidance from the Office of Management and Budget. PHMSA's analysis understates the costs and overstates the benefits of the proposed compliance activities. INGAA evaluated the costs of the Proposed Rule and estimates that the costs for gas transmission operators will range between $228 to $516 million annually, in comparison to PHMSA's assumption of $14.9 million per year.

The agency has also failed to accurately evaluate the cost effectiveness of the rule. PHMSA's cost effectiveness figure is $23,763 per metric ton of methane. By comparison, in 2022, EPA, the lead federal environmental regulator, used a cost effectiveness calculation of $1,970/ton indicating a significant delta between EPA and PHMSA's calculations.[89] Based on the PHMSA average emission reduction of 627 metric tons of methane reduction annually, INGAA calculated the cost effectiveness between $363,636 to $822,967 per metric ton of methane. INGAA recommends that PHMSA reconsider the benefits of the rule to ensure that provisions of the NPRM are cost effective.

[88] PRIA at 16.
[89] https://www.govinfo.gov/content/pkg/FR-2022-12-06/pdf/2022-24675.pdf, at 74718 Section E.

C. Several significant aspects of the proposed rule are not supported by the cost-benefit analysis.

The Pipeline Safety Act requires PHMSA to conduct a risk assessment for each pipeline safety standard proposed under 49 U.S.C. § 60102. Section 60102(b)(3) states that in preparing a risk assessment PHMSA must:

(A). Identify the regulatory and nonregulatory options that the [Agency] considered in prescribing a proposed standard;
(B). Identify the costs and benefits associated with the proposed standard;
(C). Include—
  (i) an explanation of the reasons for the selection of the proposed standard in lieu of the other options identified; and
  (ii) with respect to each of those other options, a brief explanation of the reasons that the [Agency] did not select the option; and
(D). Identify technical data or other information upon which the risk assessment information and proposed standard is based.

As part of the rulemaking process, the Pipeline Safety Act requires PHMSA to make the risk assessment for a proposed standard "available to the general public" for comment and to present the risk assessment information to the Gas Pipeline Advisory Committee (GPAC) for peer review[90]. Failing to comply with the risk assessment requirements in the Pipeline Safety Act in developing a proposed standard violates the Pipeline Safety Act and provides a basis for vacating any subsequent final rule[91].

The Associations believe that the risk assessment that PHMSA prepared for its proposed leak detection and repair rule fails to satisfy the requirements in the Pipeline Safety Act, for several significant reasons, including but not limited to the issues noted below.

First, the PRIA concedes that the Agency failed to quantify the safety benefits of the significant new requirements imposed by the Proposed Rule, stating that "[d]ue to the difficulty of predicting the probability of leaks estimated above to result in injuries, fatalities, or other damages and the severity of the damages, PHMSA did not monetize the safety benefits of the proposed rule but notes that these benefits could be significant." As the U.S. Court of Appeals for the District of Columbia Circuit recently explained in *GPA Midstream Ass'n v. United States Dep't of Transportation*, the Agency must adequately consider the benefits of a proposed standard to comply with risk assessment requirements in the Pipeline Safety Act[92]. The explanation that PHMSA provided in the PRIA for not quantifying the safety benefits of the proposed changes to the leakage survey requirements is inadequate for, as the D.C. Circuit explained in *GPA Midstream Ass'n v.*

[90] 49 U.S.C. § 60102(b)(4).
[91] *GPA Midstream Ass'n v. United States Dep't of Transportation*, 67 F.4th 1188 (D.C. Cir. 2023).
[92] *Id. at* 1200-1201.

United States Dep't of Transportation, "[q]uantifying benefits always requires making projections."[93]

In addition to simply not attempting to quantify the safety benefits of its Proposed Rule, it appears that the Agency assumed significant environmental benefits related to repairing small, Grade 3 leaks while failing to fully account for the cost and, significantly, the GHG emissions resulting from operators having to conduct additional surveys to locate, excavate and repair these small, non-hazardous leaks and then conduct a post-repair recheck. In fact, in many cases, industry's analysis indicates that the GHG emissions resulting from the identification and repair of these small leaks, and the post-repair recheck, will produce more GHG emissions than repairing the leak, eliminating any climate benefits resulting from completing the repair (See Section X.B.7 for additional detail).

Furthermore, the "alternatives considered" by PHMSA in the PRIA, pursuant to Executive Order 12866, are of limited value in terms of describing equivalent alternatives. PHMSA gave no consideration to alternative requirements related to leak grading & repair criteria, minimum sensitivity for ALDP equipment, transmission leak survey and patrol frequencies, or alternative relief valve provisions.

The following examples show specific areas where PHMSA's cost/benefit analysis is incorrect. Given the inadequate amount of time provided to review the proposed rule, Preliminary Regulatory Impact Analysis, Leak Detection Forms (five forms and five sets of instructions), Gas Gathering NPMS Attribute Standards, multiple EPA proposed rules, and *ex parte* meeting summaries, the following is not a complete list:

- Given PHMSA's proposal to disallow Grade 3 leak classification on gas transmission pipelines, transmission operators must fix all detectable leaks within six months, if not sooner. However, the Agency has not evaluated the costs of this timeframe in its regulatory impact analysis. The Agency should revise its regulatory impact analysis to evaluate the costs of excepting Grade 3 leak classification from transmission pipelines and Type A or Type C regulated gas gathering lines. Moreover, the Agency's conclusion that the cost of repairing a leak is $5,650, or with follow-up activities, $5,868 per leak, is incorrect. The Associations believe that this is not an appropriate method for estimating these cost impacts and is an oversimplification of the complexity of repairing leaks, particularly on valves and other above-ground facilities. Repairs of leaks on cross country lines (where access and environmental permitting and impact mitigation are major cost drivers) and leaks in city streets and state highway rights-of-way (which require permitting and extensive traffic control or road closures) could be substantially more expensive than $5,868 per leak to repair (See Section X.B.13 for additional detail).

[93] *Id.* at 1200 (Stating that "without quantified benefits to compare against costs, it is not apparent just how the agency went about weighing the benefits against the costs").

- PHMSA estimates that the costs associated with the new ALDP requirements would be $12 million. This cost is incorrect. PHMSA relies on too narrow of a dataset and its analysis of the costs of its leakage survey proposal are inaccurate. PHMSA based its per-mile cost for leakage surveys on information from a single operator. That operator's mileage and system parameters are not indicative of the entire industry. In fact, a member of one of the Associations estimated that their costs would increase by $24 million a year using PHMSA's assumed rate of $515 per mile. The Agency also acknowledges that it "did not find good estimates of the costs of conducting leak surveys using traditional survey methods only and therefore lacked sufficient information to determine whether the transition to ALD[P] methods results in incremental costs on a per mile basis[94]" (See Sections X.C.8 and X.C.9 for additional detail).

- PHMSA's established baseline for transmission patrols is not supported by the Office of Management and Budget's Circular A-4 or related case law. The Office of Management and Budget (OMB) directs executive agencies to identify a baseline when evaluating the benefits and costs of a proposed regulation and its alternatives[95]. OMB defines the baseline as "what the world will be like if the proposed rule is not adopted"[96] and then the agency compares the cost of that approach with its proposal.[97] Incremental costs are then defined as the "difference between a proposed action's costs and the benefits and the baseline[98]". PHMSA initially states in its PRIA that the baseline for patrol costs is one to four times per year[99] but then assumes "that operators of onshore and offshore gas transmission pipelines and Type A regulated gas gathering lines perform patrols at least once per month in the baseline."[100] The Agency proceeds to calculate the costs of moving patrol requirements from one to four times per year to every month as a zero incremental cost[101]. Numerous federal courts have accepted the baseline approach and also confirmed that a baseline is what the world would look like without an agency's proposal[102]. Incorporating the voluntary practices of a single

[94] PRIA, at 41.
[95] OMB Circular A-4, United States Office of Management and Budget Circular A-4 (Circular A-4) (Sept. 17, 2003), available at https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/circulars/A4/a-4.pdf
[96] OMB Circular A-4 at 15.
[97] *Cape Hatteras Access Pres. All. v. U.S. Dep't of Interior*, 344 F. Supp. 2d 108, 130 (D.D.C. 2004).
[98] OMB Circular A-4 at 16.
[99] PRIA, at 37.
[100] *Id.* at 37.
[101] *Id.* at 37 ("Given baseline practices, PHMSA estimates that the proposed enhanced patrolling requirements will result in no incremental costs for onshore and offshore transmission and Type A regulated gas gathering pipeline patrol requirements under the proposed rule.") *See also,* PRIA, at 141 ("Operators of gas transmission and Type A gas gathering pipelines are assumed to perform patrols at least once per month in the baseline under current practice…and therefore there are zero incremental costs for patrol requirements under the proposed rule.")
[102] *See Ariz. Cattle Growers' Ass'n v. Salazar*, 606 F.3d 1160, 1173 (9th Cir. 2010); *Fisher v. Salazar*, 656 F. Supp. 2d 1357, 1371 (N.D. Fla. 2009); *Cape Hatteras Access Pres. All. v. U.S. Dep't of Interior*, 344 F. Supp. 2d 108, 130 (D.D.C. 2004).

operator as the baseline for the entire industry is not supportable and contrary to the direction of OMB's Circular and conclusions in federal case law (See Section X.D.2.b for additional detail).

- The risk assessment that PHMSA prepared for the proposed amendments to Part 193 fails to satisfy the requirements in the Pipeline Safety Act, particularly with respect to the proposed leakage survey requirements in 49 C.F.R. § 193.2624. The PRIA appears to rely on the risk assessment that PHMSA prepared to satisfy the rulemaking mandate in Section 113 in evaluating the proposed regulations for all gas pipeline facilities, including LNG facilities. But the rulemaking mandate in Section 113 does not apply to LNG facilities; it only applies to certain gathering, transmission, and distribution lines. PHMSA does not address this distinction in the PRIA. Indeed, PHMSA does not even discuss the statutory provision that authorizes it to issue safety standards for LNG facilities, 49 U.S.C. § 60103, or address any of the factors that the statute requires it to consider in proposing such standards, including the criteria that specifically apply to operations and maintenance requirements (See Section X.D.3.b for additional detail).

D. PHMSA must provide clarity on definition of Transmission line before accurately estimating the cost-benefit of this rule.

In the Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, management of Change and Other Related Amendments Final Rule[103], PHMSA introduced changes to the *Transmission line* definition in §192.3. AGA filed a Petition for Reconsideration on September 23, 2022, requesting reconsideration of the definition due to PHMSA's inclusion of the phrase "or connected series of pipelines." AGA stated in its petition that the inclusion of this phrase "would not allow a reasonable operator to be able to determine the extent of applicable regulatory obligations under PHMSA's new rule – and under EPA's greenhouse gas reporting rules for the natural gas industry (40 C.F.R. Part 98, Subpart W). The Associations remind PHMSA that this phrase "or connected series of pipelines" was not included in PHMSA's NPRM and there was limited discussion of its addition during the PHMSA's GPAC.

During two meetings in November 2022, PHMSA staff "explained PHMSA's position that the Final Rule's amendments to the definitions of 'transmission line' and 'inline inspection' remained consistent with prior interpretations of those terms in all respects raised by AGA" and that "the same would be articulated in future guidance on the Final Rule[104]".

As of the publication of this NPRM, the guidance still has not been issued by PHMSA. Therefore, the Associations are unable to verify the accuracy of PHMSA's PRIA for this

[103] Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments, 87 Fed. Reg. 52,224 – 52,279 (August 24, 2022).
[104] https://www.regulations.gov/document/PHMSA-2011-0023-0653

NPRM as uncertainty remains concerning the foundational definition of *Transmission line.* Without clarity on this definition, there is ambiguity concerning which aspects of this NPRM will apply to some pipeline facilities that may be deemed transmission under one interpretation of the definition but a distribution asset under another interpretation.

After guidance is provided on the *Transmission line* definition, PHMSA must verify that its cost-benefit analysis has accurately considered the impact of applying the *Transmission line* definition to the proposed regulations included in this rulemaking. PHMSA must also reassess which provisions of this rule apply to those assets that may be interpreted differently depending on PHMSA's final guidance.

E. PHMSA must comply with the APA and cannot prescribe safety standards in the final rule for any of the general topics referenced in the proposed rule.

At various points throughout the Proposed Rule, the Agency refers to a general topic with no supporting detail or analysis and states that PHMSA may include regulations related to that topic in "a final rule in this proceeding[105]." The general topics that the Agency references in the Proposed Rule include but are not limited to:

- Application of substantive safety requirements to Type R pipelines[106]
- Leak detection and repair requirements for hydrogen pipelines[107]
- Leakage survey and leak detection equipment requirements for underground natural gas storage facilities[108]
- Including references to specific kinds of leak detection equipment[109]
- Adding new criteria for identifying grade 1 and grade 2 leaks[110]
- Establishing an emission mitigation reduction threshold greater than the proposed 50%[111]

PHMSA cannot include legally binding requirements on these general topics in the final rule without violating the Administrative Procedure Act ("APA"). The APA requires the Agency to provide notice of "either the terms or substance of the proposed rule or a description of the subject and issues involved[112]." The APA also makes clear that the notice provided by PHMSA must be sufficient to "give interested persons an opportunity to participate in the rule making through submission of written data, views, or arguments[113]…" An agency's final rule must be "'in character with the original scheme' and

[105] 88 Fed. Reg. at 31,926-31,937.
[106] *Id.* at 31,932.
[107] *Id.* at 31,926.
[108] *Id.* at 31,926.
[109] *Id.* at 31,934.
[110] *Id.* at 31,940 and 31,942.
[111] *Id.* at 31,949.
[112] 5 U.S.C. § 553(b)(3).
[113] 5 U.S.C. § 553(c).

‘a logical outgrowth’ of the notice and comment.”[114] Courts have limited agencies’ abilities to rely on “general scope questions” to provide the “requisite fair notice.” An agency cannot rely on “mere mention[s]” to “justify any final rule that it might be able to devise by whimsically picking and choosing within the four corners of a lengthy notice.”[115] Importantly, a “notice must describe the range of alternatives being considered with reasonable specificity. Otherwise, interested parties will not know what to comment on, and notice will not lead to better-informed agency decision-making.”[116] Nor can PHMSA rely on the public comments submitted in response to the Proposed Rule to create the notice that the APA requires after-the-fact,[117] or prescribe a regulation in the final rule that is based on technical studies and data not made available during the public comment period[118]. Several of the agency’s requests for comment in the NPRM are general scoping questions. PHMSA has not provided the Associations with the requisite fair notice and opportunity to comment.

The Agency would also be violating the additional and more stringent rulemaking requirements in the Pipeline Safety Act by including regulations on these general topics in the final rule[119]. PHMSA is required to prepare a risk assessment for each proposed standard under the Pipeline Safety Act, and that risk assessment must identify the regulatory and non-regulatory options considered, as well as the costs and benefits associated with proposed standard, provide the reasons for selecting the proposed standard, and identify the technical data or other information that provides the basis for the risk assessment and proposed standard[120]. The public must be afforded the opportunity to review and provide comments on the risk assessment during the rulemaking process, and the GPAC must be afforded the same opportunity in performing the peer review function intended under the Pipeline Safety Act[121]. The Agency has not prepared a risk assessment for the general topics referenced in the Proposed Rule, the public has not been afforded the opportunity to review and provide comments on that risk assessment, and the GPAC will not be able to consider the same as part of any subsequent peer review process. Accordingly, the Pipeline Safety Act prohibits PHMSA from prescribing any safety standards in the final rule related to these general topics.

---

[114] *Natural Resource Defense Council v. EPA*, 824 F.2d 1258, 1283 (1st Cir. 1987) (quoting *South Terminal Corp. v. EPA*, 504 F.2d 646, 658 (1st Cir. 1974); *BASF Wyandotte Corp. v. Costle*, 598 F.2d 637, 642 (1st Cir. 1979)).
[115] *Id.* at 1378 (quoting *CSX Transp., Inc.*, 584 F.3d at 1082).
[116] *Small Refiner Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 549 (D.C. Cir. 1983).
[117] *American Federation of Labor and Congress of Indus. Organizations v. Donovan,* 757 F.2d 330, 340 (D.C. Cir. 1985) (noting that an agency “cannot bootstrap notice from a comment.)”
[118] *American Public Gas Association v. United States Department of Energy,* 2023 WL 4377914, *7 (D.C. Cir. 2023) (internal citations omitted).
[119] 49 U.S.C. § 60102.
[120] *Id.* at (b)(2)-(3).
[121] *GPA Midstream Association v. U.S. Dep’t of Trans.,* 67 F.4th 1188, 1197-1198 (D.C. Cir. 2023.).

F. PHMSA must align its proposed rule with proposed and anticipated EPA regulations

PHMSA's proposed rule appears designed to work in conjunction with EPA's anticipated final rule, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" ("Oil and Gas NSPS"). For example, PHMSA's proposed regulatory text at §192.703(d) exempts certain aspects of PHMSA's proposed rule if the facility is subject to certain aspects of EPA's OOOO series regulations. However, EPA's OOOO series regulations are currently undergoing revision as part of a whole-of-government climate review mandated by President Biden's Executive Order of January 20, 2021, titled, "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crises". Per the most recent Unified Regulatory Agenda, EPA anticipates that it will issue its final Oil and Gas NSPS in August 2023.

PHMSA will need to reconcile its proposed rule with the regulatory requirements imposed by EPA's Oil and Gas NSPS and ensure that any regulation it promulgates related to reducing methane emissions is consistent with EPA's regulation and does not impose contradictory, conflicting, or inconsistent requirements on regulated entities. As noted in the Associations' letter of May 30, 2023, requesting a 60-day extension to the public comment period for the Proposed Rule, because EPA's final regulatory text has yet to be released, the Associations are not able to provide any meaningful or informed comment on how PHMSA's proposed rule aligns with EPA's regulations. Similarly, EPA, on August 1, 2023, published a supplemental proposal revising Subpart W of the Greenhouse Gas Reporting Program. Given the significant interplay between PHMSA's proposed rule and these pending EPA regulatory actions, PHMSA should delay establishing jurisdiction over facilities subject to EPA's OOOO series regulations and allow the EPA to finalize its requirements. Additionally, the Associations renew their request for an additional public comment period after EPA issues its final Oil and Gas NSPS in order to allow interested stakeholders to provide comment on certain aspects of PHMSA's proposed rule with a more complete understanding of how PHMSA's proposed rule aligns with EPA's regulation.

VIII. Fulfillment of Leak and Methane Emission Mitigation Through DIMP

Distribution Integrity Management eliminates hazardous leaks and also reduces methane emissions on gas distribution pipeline systems.

Distribution Integrity Management regulations were promulgated in 2009 with integrity management plans developed by operators by August 2, 2011. Over the past 12 years, gas distribution pipeline operators have been implementing integrity management regulations that require them to know their system, identify threats to their system, implement measures to address those risks, and monitor the effectiveness of those measures. The Distribution Integrity Management Program (DIMP) plan is foundational to how any gas distribution operator directs maintenance activities and invests in modernizing its infrastructure.

Since 2011, operators have been reporting the total leaks and hazardous leaks eliminated or repaired to PHMSA via the F7100.1[122] - PHMSA's Gas Distribution System Annual Report. These leaks are categorized by the leak causes. Leak data also serves as the single largest data source illuminating where existing threats occur on the distribution system. Operators utilize this information to "determine and implement measures designed to reduce the risk from failure of its gas distribution pipeline. These measures must include an effective leak management program (unless all leaks are repaired when found)[123]."

One of the most common risk mitigation measures implemented by gas distribution operators is increasing the leak survey frequencies for specific asset or material types (above what is currently required by §192.723). Operators are surveying leak prone pipe, such as the materials identified in the §192.723(d) of this rulemaking, more frequently to reduce risk to their system and meet current DIMP regulatory requirements. Even prior to DIMP regulations, PHMSA understood that "some operators have already implemented additional risk control and mitigation activities voluntarily. It is possible that these ongoing actions already adequately address the risks that are significant to some pipeline systems[124]."

By comparing leak data prior to DIMP requirements (2010) and after (2021), there is an obvious shift of the percentage of leaks from time dependent threats (such as corrosion) to static threats (such as equipment failure). See Table 1 below. There have only been 6 reportable incidents from time-dependent threats on natural gas distribution systems in the past 12 years since DIMP was promulgated. This represents less than 2% of all incidents. (See Table 2) This shift shows that operators are finding and repairing leaks on their system before incidents occur. Clearly, the DIMP regulation is working as intended; a performance-based regulation that provides the operator the flexibility to implement actions to address threats as identified by the risk model.

Table 1. Hazardous Leaks on Distribution Mains and Services Before and After DIMP Regulations

Threat		**% Hazardous Leaks on Mains 2010**	**% Hazardous Leaks on Mains 2021**	**% Hazardous Leaks on Services 2010**	**% Hazardous Leaks on Services 2021**
Time Dependent Threat	Corrosion Failure	23%	17%	23%	16%
Static Threats	Equipment Failure	6%	7%	12%	23%

[122] OMB No. 2137-0629. Gas Distribution System Annual Report. Part C – Total Leaks and Hazardous Leaks Eliminated / Repaired During Year.
[123] 192.1007(d)
[124] DIMP FAQ C.4.d

	Pipe, Weld, Joint Failure	8%	10%	8%	6%
Time Independent Threats	Incorrect Operation	1%	3%	2%	3%
	Natural Forces	11%	8%	4%	4%
	Excavation Damage	32%	41%	35%	38%
	Other Outside Force Damage	2%	2%	3%	7%
Other Incident Cause		17%	11%	13%	4%

Table 2. PHMSA Reportable Incidents on Natural Gas Distribution Systems by Threat Type

Threat[125]		**# of Incidents (2011 – 2023)**	**% Total Incidents**
Time Dependent Threat	Corrosion Failure	6	2%
Static Threats	Equipment Failure	13	3%
	Pipe, Weld, Joint Failure	11	3%
Time Independent Threats	Incorrect Operation	17	4%
	Natural Forces	23	6%
	Excavation Damage	164	42%
	Other Outside Force Damage	119	30%
Other Incident Cause		39	10%

Table 2 also demonstrates the lack of effectiveness prescriptive increases in leak survey will have on reportable incidents and thus reducing overall methane emissions. Over 82% of gas distribution incidents over the past 12 years have been due to time independent threats such as excavation damage and other outside force damage (such as vehicles hitting above ground assets, like meter sets).

By introducing prescriptive leak survey frequencies, PHMSA is creating contradictions within its own regulations. DIMP is a performance-based regulation that allows the operator to focus its resources to increase leak survey frequencies based upon the material type, leakage rates, and known industry issues. PHMSA's new proposal supersedes or overlaps these measures by layering PHMSA prescribed frequencies for leak surveys. By doing so, PHMSA is effectively eroding its distribution integrity management regulation, which has proven impactful with the reduction in incidents due to corrosion and other time-dependent threats.

[125] Pipeline Safety: Deactivation of Threats. ABD-2017-01. 82 Fed. Reg. 14108 (March 16, 2017).

IX. PHMSA's must lengthen its effective date for the proposed requirements

The Associations believe there will be unintended consequences resulting from the proposed rule's unreasonably short, six-month effective date. The compressed timeframe provided to operators to make extensive operational changes has the significant potential to negatively impact public safety. For example, the resources required to perform additional leak surveys, leak re-evaluations, and leak repair rechecks under the proposed rule are excessive. An operator's reallocation of resources to perform additional leak surveys, leak reevaluations, and leak repair rechecks will impede its efforts to perform additional and accelerated actions that reduce risk under an operator's DIMP and TIMP plans, including those to prevent excavation damage and outside force damage. It is imperative that PHMSA provide at least 36-months for operators to implement the significant new requirements imposed by the proposed rule.

X. Technical Comments

A. Miscellaneous Changes in Parts 191 and 192 To Reflect Codification in Federal Regulation of the Congressional Mandate To Address Environmental Hazards of Leak From Gas Pipelines

The Associations believe not all detectable leaks warrant an immediate response since many leaks do not pose an imminent risk to public safety or the environment. PHMSA should maintain distinctions between leaks, leaks hazardous to persons and property, and leaks significantly impacting the environment. Clear regulatory definitions must be established, and these definitions must be used consistently by PHMSA throughout the pipeline safety code and in its various reporting forms.

1) __Adherence to Congressional mandate related hazardous leaks__

PHMSA's starting point for defining a leak should be its existing definition and the statutory mandate Congress enacted. Congress directed PHMSA to identify, locate and categorize leaks that are:

- Hazardous to human safety or the environment; or
- Have the potential to become explosive or otherwise hazardous to human safety.

The Agency asserts in its proposed rule that its regulations have lacked "meaningful guidance regarding which leaks are hazardous." This is incorrect. Since 2009, PHMSA has defined a "hazardous leak" as "*a leak that represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous.*"[126] While this definition is specific to Distribution Integrity Management, many operators not subject to that regulation have voluntarily incorporated this definition into their procedures. PHMSA has also encouraged gas

[126] 49 CFR 192.1001

transmission operators to use this definition[127]. The agency included a definition of leaks in the annual report instructions ("unintentional escapes of gas from the pipeline that are not reportable as incidents under Section 192.3.") and for years, applied it to transmission operators. The agency has consistently stated in guidance starting in 1972 that while hazardous leaks must be repaired promptly, the decision as to which leaks are hazardous depends on the nature of the operation and local conditions[128]. The Agency has acknowledged that the "nature and size of the leak, its location, and the danger to the public are among factors that must be considered by the operator."

Additionally, PHMSA's proposal to have separate definitions pertaining to leaks and hazardous leaks in the integrity management regulations (Subparts O and P) would lead to confusion, particularly when one considers that integrity management principals are followed in other subparts in Part 192. The recordkeeping process of maintaining separate records for consideration in integrity management versus in compliance with the balance of federal pipeline safety regulations is confusing and very problematic. This approach will likely lead to recordkeeping errors. Furthermore, stakeholders unfamiliar with the shift in definition would be left contemplating why the quantity of "hazardous leaks" exponentially grew because of this rulemaking – when the definition changed, not the number of leaks on natural gas assets.

The Associations recognize that PHMSA has defined a leak as "an unintentional escape of gas from the pipeline" for years in the annual report instructions. With that background and the text of the statute in mind, the Associations support the following definition of a leak:

> *Leak means any uncontrolled release of gas from a pipeline that is designed to transport, deliver, or store gas.*

Section 113 of the PIPES Act of 2020 clearly acknowledges the existence of non-hazardous leaks (e.g., "potential to become…hazardous", "leak so small that it poses no potential hazard," etc.). Furthermore, a small and unquantified environmental harm is not consistent with PHMSA's historical definition of "hazardous": *an existing or probable hazard to persons or property [requiring] immediate repair or continuous action until the conditions are no longer hazardous.* Therefore, the Associations strongly disagree with PHMSA's proposal to make "hazardous leaks" and "leaks" synonymous and recommend codification for two separate definitions: "leak" and "hazardous leak."

The Associations believe criteria for "hazardous leaks" should remain primarily focused on existing or probable hazard to persons or property, as this determination is one that can

---

[127] PHMSA acknowledged in its Operations and Maintenance enforcement guidance that "while this definition is only applicable to distribution systems, it may provide guidance for defining hazardous leaks." Operations and Maintenance Enforcement Guidance at 92.

[128] PHMSA Letter of Interpretation, PI-72-0109 (Aug. 4, 1972). This interpretation is also cited in the agency's PHMSA Operations and Maintenance Enforcement Guidance which has been in effect since 2010. *See* Operations and Maintenance Enforcement Guidance at 92.

be most realistically made using the judgment of operating personnel at the scene of a leak. PHMSA also failed to consider the impact the conflation of these two definitions would have on tracking and trending of leak data by individual operators and across the industry. Any change to definitions in 49 CFR 191 and 192 must be mirrored in Annual Report requirements per §§ 191.11 and 191.17.

For these reasons, the Associations recommend PHMSA relocate the existing definition for *Hazardous leak* as defined in 192.1001 to the general section of Part 192, 192.3:

> *Hazardous leak* means a leak that represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous.

The proposal to define leak and hazardous leak separately allows PHMSA to stay true to its Congressional mandate, removes potentially confusing and conflicting definitions within 49 CFR 192, and continues to prioritize the safety of persons and property.

2) Clarification of the term 'uncontrolled' in the leak definition

PHMSA should revisit its understanding of the term "uncontrolled" in defining a leak. It is concerning to the Associations that the Agency states in the preamble that "unintended releases through intended release pathways" are leaks. PHMSA also specifically references releases from relief devices and emergency shutdown devices as leaks. However, releases from relief devices, emergency shutdown devices, vent stacks, and other similar devices are controlled and therefore should not be considered a leak. Operators are required under the pipeline safety regulations to design certain pipeline components to safely release gas in a controlled manner without hazard. PHMSA should clarify use of this terminology to ensure that releases of gas through devices or pathways – in the manner that those devices were intended, designed, and constructed to safely release gas – are not to be considered "uncontrolled."

3) Removal of reference to identification of leaks by "touch"

The Associations request that PHMSA not suggest that a leak should be identified by touch. Placing a digit or a portion of the body in the path of a leak in order to identify or pinpoint it is potentially dangerous and is not a practice that should be used to locate, identify, or grade leaks.

4) Preserving the "potentially" qualifier for leaks found during pressure testing

Given the Associations' objection to making "leaks" and "hazardous leak" synonymous, PHMSA's proposal to strike "potentially" from all Subpart J provisions related to detection of "potentially hazardous leaks" during pressure testing is problematic. Striking the qualifier "potentially" only makes sense if all leaks are de facto hazardous. With the understanding that all detectable leaks are not hazardous leaks, the Associations recommend PHMSA refrain from changing qualifiers that exist in 49 C.F.R. §§192.507, 192.509 and 192.513.

§ 192.503 General requirements.

(a) No person may operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced, until—

(1) It has been tested in accordance with this subpart and § 192.619 to substantiate the maximum allowable operating pressure; and

(2) Each **potentially** hazardous leak has been located and eliminated.

….

§ 192.507 Test requirements for pipelines to operate at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. (689 kPa) gage.

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. (689 kPa) gage must be tested in accordance with the following:

(a) The pipeline operator must use a test procedure that will ensure discovery of all **potentially** hazardous leaks in the segment being tested.

….

§ 192.509 Test requirements for pipelines to operate below 100 p.s.i. (689 kPa) gage.

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated below 100 p.s.i. (689 kPa) gage must be leak tested in accordance with the following:

(a) The test procedure used must ensure discovery of all **potentially** hazardous leaks in the segment being tested

…

§ 192.513 Test requirements for plastic pipelines.

(a) Each segment of a plastic pipeline must be tested in accordance with this section.

(b) The test procedure must ensure discovery of all **potentially** hazardous leaks in the segment being tested.

5) ***Preserving ability to monitor leaks determined not to be potentially hazardous during uprating***

In §§ 192.553 and 192.557, PHMSA proposes to eliminate existing language that would allow an operator to monitor a non-hazardous leak and continue with uprating procedures if it does not become potentially hazardous. This is an impactful change. Modifying § 192.553(a)(2) seriously impacts the feasibility to conduct uprates both economically and in a timely manner, while minimizing impact on safety and the environment. The uprating process is vital to the integrity of the natural gas distribution system.

The Associations urge PHMSA to consider allowing operators to grade, monitor, and repair leaks in accordance with proposed § 192.760 while proceeding with uprating procedures. A blanket requirement to repair any leak, even those identified by Congress as so small that they would not create a potential hazard, is unreasonable and lacks technical support. This position diverts from GPTC guidance that has long recognized a detectable leakage rate criteria during pressure testing. These leaks, when present, are typically found on pressure test headers that are not part of the pipeline placed into service following pressure testing. PHMSA's explanation for their proposal demonstrates that they did not consider leaks during pressure tests that are not on piping that is ultimately placed into service. The Associations recommend that PHMSA refrain from making changes to Sections 192.553 as these changes are not justified and are based upon a flawed assumption of how they are used by operators.

§ 192.553 General requirements.

- (a) Pressure increases. Whenever the requirements of this subpart require that an increase in operating pressure be made in increments, the pressure must be increased gradually, at a rate that can be controlled, and in accordance with the following:
  - (1) At the end of each incremental increase, the pressure must be held constant while the entire segment of pipeline that is affected is checked for leaks.
  - (2) Each leak detected must be repaired before a further pressure increase is made, **except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous**~~.~~

    ….

§ 192.557 Uprating: Steel pipelines to a pressure that will produce a hoop stress less than 30 percent of SMYS: plastic, cast iron, and ductile iron pipelines.

- (a) Unless the requirements of this section have been met, no person may subject:
  - (1) A segment of steel pipeline to an operating pressure that will produce a hoop stress less than 30 percent of SMYS and that is above the previously established maximum allowable operating pressure; or
  - (2) A plastic, cast iron, or ductile iron pipeline segment to an operating pressure that is above the previously established maximum allowable operating pressure.
- (b) Before increasing operating pressure above the previously established maximum allowable operating pressure, the operator shall:
  - (1) Review the design, operating, and maintenance history of the segment of pipeline;

(2) Make a leakage survey (if it has been more than 1 year since the last survey) and repair any leaks that are found, **except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous.**

B. Leak Grading and Repair—§§ 192.703 and 192.760

For several decades, leak grading criteria has been based exclusively on the prioritization of public safety. The Associations believe that the GPTC guidance used by operators has played a critical role in establishing a standard methodology in evaluating the severity of a leak.

The industry recognizes PHMSA's responsibility to consider environmental impact in the grading, monitoring, and repair of leaks. However, the Associations firmly disagree with the broad designation of essentially all detectable leaks as "hazardous." The use of the term "hazardous" has historically been used exclusively in the context of public safety. It has clear implications on how leaks have historically been graded by operators, which is a critical issue for PHMSA to acknowledge as the industry is broadening its perspective with environmental considerations. The non-zero but relatively negligible future harm to the environment caused by an individual leak cannot be placed on a par with an immediate hazard to persons or property, otherwise the word "hazardous" is stripped of its meaning. Therefore, the Associations believe that PHMSA would be making a serious mistake to promulgate blanket regulatory requirements that give the environment **equal** priority to public safety. The federal pipeline safety code can only have one top priority and it must continue to be public safety, which is the immediate protection of persons and property.

1) General Requirements

The definition of "leak," as proposed in this NPRM (with suggested revisions by the Associations) is an important qualifier for the General requirements proposed in § 192.703(c). The Associations support PHMSA's application of grading requirements as being limited to confirmed leaks (and not merely investigations of leak indications).

Leak investigations are commonly triggered by one of two events: a customer odor call for a suspected gas leak or methane indications from a scheduled leak survey that has been conducted by an operator. Odor calls are reports of gas odor by an individual (customer, member of the public, and occasionally an employee of the gas system). The operator or emergency services will respond to these calls and search for the source of the gas odor. It is important to note that a significant percentage of odor calls do not result in the discovery of a natural gas leak (and, relatedly, there can be many odor calls associated with a single leak). For example, some reported natural gas odors may be attributed to other sources or factors unrelated to natural gas; others may be attributed to leaks on piping not jurisdictional to the operator. Nevertheless, odor calls are taken seriously and responded to urgently. Upon arrival at the scene, responders assess the situation (determine potential risks) to ensure the safety of individuals and the surrounding area.

By contrast, scheduled leak surveys are proactively conducted by operators to search for potential leaks in their infrastructure. Methane detection instruments are used during these surveys to identify the presence of methane, which can help locate potential leaks that may not be immediately recognized by human senses, such as smell or sight.

Leak pinpointing is a required precursor to accurately grading leaks and thus, determining appropriate responses from the operator. It involves precisely locating the source and spread of a gas leak using specialized tools in a sampling process. Pinpointing the leak's location is essential to evaluating the impact of other variables like proximity to ignition sources, proximity to persons and property, ventilation conditions, migration potential, and other safety considerations. By taking these factors into account, the severity and urgency of a leak can be accurately assessed, allowing for appropriate actions and responses to be taken.

Additionally, the General requirements proposed for § 192.760 must provide flexibility for the operator to eliminate a leak through immediate and continuous action, without first grading the leak. As written, § 192.760(a)(3) would require an operator to always determine a leak grade before a repair is made. The requirement to first determine leak grade may unnecessarily delay and immediate repair of a leak and impede the mitigation of risk to public safety.

2) Grade 2 leaks

The Associations contend that the proposed Grade 2 leak criteria in the NPRM specifying operators to determine if leakage rate exceeds 10 cubic feet per hour (cfh) is not feasible for practical application for several reasons:

- The equipment that meets this standard is not widely used and, therefore, operators would need time to switch to this equipment. PHMSA would need to account for those costs in the PRIA.

- A 10 cfh leak is extremely small at transmission pipeline pressures and therefore is not a good measure to use to classify Grade 2 leaks. For instance, the volumetric leak rate at 850 psig is approximately 55 times larger than the volumetric leak rate at 1 psig. The volumetric leak rate at 60 psi is almost 10 times larger than the volumetric leak rate at 1 psig.

- Operators who have equipment that is purported to take these measurements note that the readings are clearly classified as estimates; the measurement precision is too limited to give confidence in the accuracy of individual readings. The technology has not yet evolved to the point of accurately *and* consistently measuring flow rates from a leaking pipeline.

- Direct measurement by field personnel of actual (not estimated) leakage rate for *all* non-Grade 1 leaks would be a practical impossibility given not only the number of leaks involved, but the number that are below grade (thus requiring excavation, exposure, and measurement of the leakage) or at elevated points on above ground compressor station piping that are only accessible with specialized equipment. Furthermore, such direct measurement exercises would be burdensome and distracting to field personnel whose on-site priority is to evaluate and mitigate the immediate safety threat to persons and property. Additionally, there are safety concerns in operators attempting to precisely size the leakage hole.

- Requiring operators to use leakage rate to discern between Grade 2 and Grade 3 leaks is in contradiction to PHMSA's proposal to define minimum sensitivity of leak detection equipment by parts-per-million gas alone (as proposed in § 192.763(a)(1)(ii)). Tying leak grading criteria to determination of volumetric leakage rate introduces a de facto secondary performance standard and nullifies the "flexibility for operators to choose from a baseline of high-quality equipment for their unique needs" that PHMSA has sought to establish in the ALDP requirements. Supplementing the criteria for grading leaks by environmental significance – including, but not limited to leak migration extent (as cited by PHMSA in the NPRM; see FR page 31941) – is necessary in order to provide operators the flexibility and technological wherewithal to perform this evaluation, without the need to measure or estimate leakage rate. Establishing clear criteria that can be implemented effectively across the industry is crucial, particularly when operators are relying on the criteria to make decisions that impact public safety and environmental stewardship.

Criteria for grading leaks based on environmental significance should contain a list of methods operators could potentially apply, based on available technologies and the judgment of the operator. Because of the variability in available equipment and skills in operating such equipment, operators should only be required to apply <u>one</u> method under 192.760(c). These must include, at a minimum, not only prescriptive thresholds for estimated leakage rates, but also (consistent with precedent[129] in state pipeline safety regulations[130]) leakage extent in square feet. Operators must be given latitude to define and utilize alternative methods for determining whether a non-hazardous leak should be classified as Grade 2 based on its potential for environmental harm, according to the

[129] 220 Mass. Reg. 114.07. *(a) Each Gas Company shall designate Grade 3 gas leaks as environmentally significant if during the initial identification or the most recent annual survey if: 1. the highest barhole reading shows a gas-in-air reading of 50% or higher or 2. the Leak Extent is 2,000 square feet or greater.*

[130] The Associations recommend against adoption of the Massachusetts criteria for environmental significance based on 50% or higher gas readings, as a single bar hole is not indicative of leakage significance, and because such a criterion may disincentivize operators from putting down bar holes.

operator's unique judgment, system knowledge, and available leak detection technologies.

Beyond the leak grading criteria, the proposed 6-month repair timeframe for Grade 2 leaks presents significant challenges to operators. Many cities have moratoriums on any non-emergency work on public right aways (streets, sidewalks, parkways) during special events and holiday seasons. Seasonal disruptions due to weather, resource variability, and other constraints means that the 6-month repair interval could be artificially shortened and/or impractical to meet. A 12-month repair interval for Grade 2 leaks is appropriate, with additional provisions allowing for delay due to permitting restrictions beyond the control of the operator. Delays in permit issuance and supply chain often occur, making it challenging to complete repairs within the designated timeframe. Paving moratoriums, highway and railroad permits, and environmental or seasonal matters can also affect the timing of repairs. Furthermore, operators in remote parts of the country (like those on the Alaska North Slope (ANS)) who require specialty rated components to withstand temperatures down to -50°F can affect repair timelines. These factors that are not in the operator's control must be considered to ensure realistic and achievable repair timeframes.

Additionally, extending the repair interval for Grade 2 leaks will allow operators to fully leverage project bundling. Many operators already bundle work (when practicable) to prevent the need to excavate, blow down, and purge the same pipeline multiple times. Project bundling is already recognized[131] as an effective method of, and best practice for, reducing vented emissions. It also necessarily builds efficiencies in maintenance and construction activities and lowers associated costs. However, as leak repair intervals are compressed, project bundling becomes less feasible.

The Associations are likewise firmly opposed to the 30-day repair requirement proposed for Grade 2 leaks in Class 3 and 4 locations. The Associations contend that the risk of leakage relative to proximity to buildings of human occupancy is already mitigated by the Grade 1 leak criteria. Furthermore, if any leak that would otherwise meet Grade 2 (or Grade 3) leak criteria is (in the operator's judgement) determined to be an immediate safety concern, it would then be classified and remediated as a Grade 1 leak. Therefore, the shorter interval is unnecessary and promotes an arbitrary deadline without a reasonable basis. It also increases costs and possible emissions that could be avoided by bundling with other work on the pipeline segment.

Also, as proposed, there is no provision for requesting an extension to repair Grade 2 leaks in § 192.760(c), unlike associated provisions for Grade 3 leaks in § 192.760(d). The

[131] al-Mukdad, et al., California Public Utilities Commission, "Natural Gas Leakage Abatement Summary of Best Practices, Working Group Activities, And Revised Staff Recommendations" (Jan. 2017), *https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/documents/final-best-practices-revised-staff-recommendations-with-bp-matrix-january2017.pdf* (Last accessed on Aug. 15, 2023).

Associations believe that operators should have the opportunity to request extensions for both Grade 2 and Grade 3 leaks to accommodate various circumstances and challenges. This flexibility would ensure a more practical and effective approach to scheduling and performing leak repairs and would allow operators to prioritize risk appropriately as new leaks are discovered.

Furthermore, the Associations are firmly opposed to the provisions proposed in § 192.760(c)(4), which effectively introduces a fourth leak grade by requiring operators to prioritize all Grade 2 leaks and repair some of them on an accelerated basis (i.e., within 30 days of detection). This requirement establishes a de facto "Grade 1.5" leak, which contravenes the standard Grade 2 leak repair interval established in § 192.760(c). Prioritizing significant volumes of Grade 2 leak repairs using a comprehensive, multifactor methodology becomes *less* practicable as the maximum repair interval (proposed by PHMSA as 6 months) is compressed. Systematizing a single grade of leaks – leaks that will be repaired in fewer than 12 months in any case (as proposed by the Associations in these comments) – into discretized subcategories with varying repair schedules is onerous and unreasonable. This is particularly true when considering the requirement to reevaluate Grade 2 leaks as per § 192.760(c)(2), which will inevitably re-prioritize any leaks which become a Grade 1. The proposed § 192.760(c)(4) (and associated verbiage for repair scheduling in § 192.760(c)(2)) should be struck from the Leak Repair and Grading requirements.

Finally, the proposed requirement to reevaluate each Grade 2 leak at least once every 30 days until it is repaired (§ 192.760(c)(2)) is unreasonably frequent given how rare it is for leaks to be upgraded from reevaluation data, based on information collected by the associations from its membership. One major gas distribution operator calculated that only 2% of Grade 2 leaks on its system were ever reclassified to Grade 1. A second operator estimated that less than 1% of Grade 2 and 3 leaks are reclassified. Given this observed behavior of graded leaks, a 30-day reevaluation interval for Grade 2 leaks cannot be supported. Consistent with the minimum frequency of reevaluations recommended by GPTC and the unjustifiably small incremental benefit of more frequent reevaluations, the Associations recommend a 6-month interval for Grade 2 leak reevaluation on gas distribution pipelines. Consistent with this 2:1 heuristic for repair scheduling and reevaluation scheduling, the Associations accordingly recommend a 45-day reevaluation interval for Grade 2 leaks on gas transmission pipelines.

3) Grade 3 leaks

Given that Grade 2 leak criteria include considerations for both public safety and environmental significance, wide latitude should be available to operators to eliminate remaining leaks (namely, Grade 3) through project bundling and pipeline replacement. In light of this necessary flexibility, as well as PHMSA's demanding vision for Grade 3 leak action criteria (which heretofore has not included prescribed repair scheduling under GPTC guidance), the Associations advocate a 36-month leak repair schedule for Grade 3 leaks. Likewise, given that Grade 3 leaks very rarely change characteristics to a degree that upgrading to Grade 2 or Grade 1 is required (as stated previously), a 12-month schedule for Grade 3 reevaluation is recommended. This minimum interval for reevaluation is not less stringent than GPTC guidance and would ensure that Grade 3 leaks in business districts are reevaluated no less frequently than the scheduled leakage surveys required by § 192.723(b).

PHMSA's proposed § 192.760 prohibits gas transmission operators from using the Grade 3 leak classification. In proposed § 192.760(c)(1)(vi), the agency states that a Grade 2 leak includes "any reading of gas that does not qualify as a grade 1 leak that occurs on a transmission pipeline or Type A or Type C regulated gas gathering line." This language, as well as the 10 cfh leakage rate criterion for Grade 2 leaks, effectively restricts a gas transmission operator from using the Grade 3 classification. PHMSA does not explain this prohibition and does not appear to evaluate the costs of such a prohibition. PHMSA's position is also inconsistent with the GPTC requirements. The Grade 3 classification should be available for all detectable leaks that fit the detailed scoping requirements in proposed § 192.760(d)(1)(i)-(v), regardless of the function or type of pipeline involved. Allowing time to properly plan projects would allow for projects to be bundled and to take full advantage of a pipeline being evacuated of natural gas. Preventing gas transmission pipeline operators from utilizing the Grade 3 leak classification could require the same segment of pipeline to be evacuated of natural gas multiple times within a relatively short window of time, thus increasing costs and GHG emissions.

4) Grading of hydrogen and LP gas leaks

Notwithstanding the Associations' position that pure hydrogen should be removed from the proposed rule until leak detection technologies for hydrogen are further developed, the proposal to grade all leakages of hydrogen at no less than Grade 2 is not supported by the available literature. The 2013 National Renewable Energy Laboratory paper[132] cited by PHMSA in the NPRM states: "If less than 20% hydrogen is introduced into distribution system, the overall risk is not significant for both distribution mains and service lines, but the service lines are more impacted than mains because they are mostly in confined spaces." The NREL cites higher risk for 50-70% hydrogen blends, which are currently unknown in gas distribution projects. A 2022 study by UC-Riverside describes 19 hydrogen blending projects from across the world that collectively suggest an acceptable blend of between 2% and 20% hydrogen[133]. While the UC-Riverside describes higher leakage rates for hydrogen blends, in the case of permeation leaks these differences are described as "much less than what can be regarded as a safety issue." In any case, proneness to leakage is not an argument for restricting the grading of a leak once it has occurred. Lastly,

---

[132] Melania, et al., National Renewable Energy Laboratory Technical Report TP–5600–51995, ''Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues'' at 16–17 (Mar. 2013), https://www.nrel.gov/docs/fy13osti/51995.pdf.

[133] Raju, et al., University of California, Riverside, "Hydrogen Blending Impacts Study" (Jul. 2022), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF.

PHMSA's statement regarding relative safety risk of hydrogen blends in transmission pipeline ruptures is simply not relevant to leakage. There is no compelling justification for precluding operators from grading hydrogen gas leaks as Grade 3 if they do not otherwise meet Grade 1 or Grade 2 criteria.

Notwithstanding the unique properties of LP gas, there is likewise nothing precluding LP gas leaks from meeting Grade 3 criteria in the GPTC guidance or any other existing literature. PHMSA's proposal to forbid LP gas leaks from being graded as Grade 3 (if they do not otherwise meet Grade 1 or Grade 2 criteria) is not supported and should be removed from any final rulemaking.

5) Effective Date for Regrading Existing Leak Inventory

The proposed criteria for Grade 1, 2, and 3 leaks in the NPRM differ from what many operators currently use and what is specified in the GPTC guidance. Once the rule is finalized, operators will need sufficient time to reevaluate their existing leaks and determine if any changes in classification are necessary. This process can be particularly time-consuming for operators with a significant inventory of leaks.

Assessing and re-grading leaks according to the new criteria will require careful review and analysis of each individual leak. It is important to allocate adequate time for this evaluation process to ensure accurate and appropriate classification of leaks. The timeframe should account for the scale of the operator's leak inventory and allow for thorough assessments to be conducted. Adequate time is required from the time of the Final Rule's effective date to ensure that existing leaks are re-graded appropriately, and procedures, IT systems, training, qualifications, and modifications to leak management systems are administered adequately. Adequate time is also necessary to repair all Grade 2 leaks found before Final Rule effective date.

By allowing operators the necessary time to reassess their existing leaks, the industry can ensure that the reclassification process is carried out effectively and in compliance with the new criteria established by the rule. This approach supports the goal of accurately categorizing leaks and implementing appropriate response measures based on the revised classification system.

6) Negative Impact of accelerated leak repair timelines on pipe replacement programs

Expedited leak repair requirements are likely to have deleterious effects to operators' long-term pipeline replacement and infrastructure modernization initiatives. Pipeline replacement programs span years and typically require submittal to, and approval from, state regulatory bodies. They are dictated by integrity management programs and require considerable planning and prioritization. Identified projects are not readily interchangeable (e.g., swapped in and out) on a year-to-year or month-to-month basis.

The accelerated leak repair requirements will require operators to allocate funds and resources toward fixing leaks on pipelines that are, or may soon be, scheduled for replacement as part of a strategic pipeline replacement project. Repairing these leaks sooner diverts resources from planned infrastructure upgrades, will delay existing replacement programs for operators that have a significant inventory of cast iron and bare steel pipe, and hinders an operator's ability to effectively execute strategic replacement plans. Essentially, an operator will be required to excavate the leak, fix the leak, rebury the pipe, fix the street or pavement, and then come back later to re-excavate, replace the entire pipeline on that street, and refix the street or pavement.

In addition, leak repair work has an impact on the individuals living near the pipelines. Crews fixing leaks utilize equipment that affects road travel, emits noise, and can at times be disruptive. The compounding impact of visiting a street or neighborhood to repair a leak on a pipeline that will soon be replaced is considerable and should not be discounted.

The expedited leak repair requirements can also impede an operator's ability to carry out other essential projects related to pipeline safety and reliability. For instance, initiatives such as converting low-pressure systems or relocating inside meters may be delayed or hindered due to resources being shifted to focus on leak reevaluations and repair activities with compressed timelines. The rule, as proposed, will force operators to move towards more reactive leak mitigation and away from proactive pipe replacement programs. Operator resources for system enhancement are finite and will be driven by regulatory requirements.

Operators need flexibility in allocating resources wisely, considering the best interests of customers. The rule should allow for prudent balancing of critical leak repairs with strategic long-term pipeline replacement projects. This ensures effective resource utilization, system reliability, and responsible financial decision-making by operators, while minimizing impacts to the public living and working near critical energy infrastructure.

The Associations support PHMSA's proposal to provide an exception to Grade 3 leak repair timelines if the segment containing the leak is scheduled for replacement, and is, in fact, replaced (§ 192.760(d)(2)(ii)). This exception is a prudent acknowledgment of the importance of safely and efficiently eliminating and preventing leaks by prioritizing long-term, risk-based strategic replacement programs. Successful execution of replacement projects can furthermore help operators achieve reduction of leak backlogs and successfully move toward a more sustainable "find and fix" regime for other leaks. However, in recognition of the need to fully realize these safety and efficiency benefits and the time horizons of the strategic replacement programs (e.g., those funded through PHMSA's Natural Gas Distribution Infrastructure Safety and Modernization grants), the exemption for Grade 3 leak repairs scheduled for replacement should be revised from five (5) years to ten (10) years. Accordingly, a similar provision should be available for Grade 2 leaks scheduled for replacement within five (5) years. "Chasing" the repair of non-hazardous leaks on pipe that will be replaced, removed, or abandoned in the medium term is a waste of resources and a distraction from risk mitigation through strategic replacement and retirement of leaking pipelines. Any "heightened potential hazards" posed by Grade 2 leaks (relative to Grade 3) are mitigated by the proposed requirements to reevaluate Grade 2 leaks on a periodic basis.

7) Repairing small leaks will emit more emissions than waiting for the pipe to be replaced

Repairing a small grade 3 leak on an accelerated timeline will actually emit more emissions than if the operator waited to repair the leak when the pipeline or component was due for replacement. An analysis of the Washington State University study, included as Appendix I, "Measurement-based emissions assessment and reduction through accelerated detection and repair of large leaks in a gas distribution network," indicates that 30% of all leaks have an average leakage rate of 0.04 cubic feet/hour. This translates to a leakage rate of approximately 0.3504 Mcf/year or 0.019 metric tons of CO2 equivalent (CO2e).

The Associations then compared the emissions expended during a leak repair. The analysis concluded that repairing a small grade 3 leak conservatively creates nearly 9 times the emissions of that grade 3 leak for a year, repairing a grade 3 leak that is under asphalt creates nearly 11 times the emissions of the grade 3 leak, and repairing a grade 3 leak under cement creates nearly 18 times the emissions of the grade 3 leak. The analysis did not account for emissions associated with the excavation process, raw material transportation, waste hauling, traffic delays, repair team revisits, road destruction, or worker transportation, among other factors. Consequently, the identified emissions likely understate the emissions impact of fixing small leaks. Below are the identified emissions:

Table 3: Total Emissions from Leak Survey and Leak Repair

	Amount	Total
Leak survey		
Average mileage driven to conduct leak survey: 2 trips/year per proposed rule	10 miles driven each way to conduct leak survey	40 miles driven
Leak survey vehicle miles per gallon (MPG)	25 MPG	
CO2 conversion factor for gas burn kg CO2/gallon	8.887 kg CO2 per gallon[134]	**0.014219 metric tons CO2e[135]**
Leak repair		
Average mileage driven to conduct leak repair[136]	30 miles driven each way	60 miles driven

[134] EPA Greenhouse Gases Equivalencies Calculator: https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator#results

[135] (40 miles/25 miles per gallon) x 8.887 kg CO2 per gallon = 14.2192 kg CO2e or 0.014219 metric tons CO2e

[136] Longer distance due to heavier equipment stored at key locations

Weight of backhoe		7.5 tons[137]
Weight of flatbed trailer to haul the backhoe and other equipment		3 tons[138]
Total weight of backhoe and flatbed		10.5 tons
Emissions from truck hauling backhoe on flatbed trailer and other equipment)	265 grams CO2e per ton mile	**0.16695 metric tons CO2e[139]**
Repair of leak under pavement		
Emissions from asphalt raw materials production[140]	7.035 kg CO2e per sq meter[141]	0.015688 metric tons CO2e[142]
Emissions from Asphalt Laying down[143]	0.139 kg CO2e per sq. meter[144]	0.000311 metric tons CO2e[145]
Emissions from Asphalt Mixing[146]	8.798 kg CO2e per sq meter[147]	0.019620 metric tons CO2e[148]
Emissions from Asphalt Compacting[149]	0.099 kg CO2e per sq. meter[150]	0.000222 metric tons CO2e[151]
Total emissions from asphalt removal and repair	16.071 kg CO2e per sq. meter	**0.035841 metric tons CO2e[152]**

137 Average weight of backhoe is 15,000 pounds: How Much Does a Backhoe Weigh? - Boom & Bucket (boomandbucket.com)
138 https://www.weigh-safe.com/towing-safety/the-ultimate-guide-to-safe-heavy-duty-towing/
139 (60 miles x 10.5 tons) x 265 grams CO2e/ton mile = 166,950 g CO2e or 0.16695 metric tons CO2e
140 https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4809014/#:~:text=About%2041.79%25%20of%20the%20GHG,compacting%20and%20the%20curing%20phase
141 3,939,785 kg CO2e for area 20,000 meters by 28 meters (560,000 square meters) or 7.035 kg CO2e per square meter
142 7.035 kg CO2e per sq. meter x 2.23 sq. meter excavation area = 15.688 kg CO2e or 0.015688 metric tons CO2e
143 https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4809014/#:~:text=About%2041.79%25%20of%20the%20GHG,compacting%20and%20the%20curing%20phase
144 78,015 kg CO2e per 560,000 sq. meters or 0.139 kg CO2e per sq. meter
145 0.139 kg CO2e per sq. meter x 2.23 sq. meter excavation area = 0.311 kg CO2e or 0.000311 metric tons CO2e
146 https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4809014/#:~:text=About%2041.79%25%20of%20the%20GHG,compacting%20and%20the%20curing%20phase
147 4,927,046 kg CO2e per 560,000 sq. meters or 8.798 kg CO2 per sq. meter
148 8.798 kg CO2e per sq. meter x 2.23 sq. meter excavation area = 19.620 kg CO2e or 0.019620 metric tons Co2e
149 https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4809014/#:~:text=About%2041.79%25%20of%20the%20GHG,compacting%20and%20the%20curing%20phase
150 55,658 kg CO2e per 560,000 sq. meters or 0.099 kg CO2e per sq. meter
151 0.099 kg CO2e per sq. meter x 2.23 sq. meter excavation area = 0.222 kg CO2e or 0.000222 metric tons CO2e
152 Does not take into account emissions from use of a jackhammer to break up asphalt, excavate and refill dirt, remove asphalt by dump truck, or additional emissions if crew unable to repair leak in one day and must return.

Total emissions from the repair of a leak under asphalt		**0.202791 metric tons CO2e[153]**
Repair of leak under cement		
Cement Raw Materials Production[154]	75.349 kg CO2e per sq. meter[155]	0.168028 metric tons CO2e[156]
Cement Laying down[157]	0.7057 kg CO2e per sq. meter[158]	0.001574 metric tons CO2e[159]
Cement Mixing[160]	0.4130 kg CO2e per sq. meter[161]	0.000921 metric tons CO2e[162]
Cement Compacting[163]	0.0623 kg CO2e per sq. meter[164]	0.000139 metric tons CO2e[165]
Cement Curing[166]	0.039 kg CO2e per sq. meter[167]	0.000087 metric tons CO2e[168]
Total emissions from cement removal and repair	76.569 kg CO2e per sq. meter	**0.17075 metric tons CO2e[169]**
Total emissions from repair of a leak under cement		**0.3375 metric tons CO2e**

[153] 0.16695 metric tons CO2e (base leak repair) + 0.035841 metric tons CO2e (emissions from asphalt removal and repair)
[154] https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4809014/#:~:text=About%2041.79%25%20of%20the%20GHG,compacting%20and%20the%20curing%20phase
[155] 42,195,469 kg CO2e per 560,000 sq. meters or 75.349 kg per sq. meter
[156] 75.349 kg CO2e per sq. meter x 2.23 sq. meter excavation area = 168.028 kg CO2e or 0.168028 metric tons CO2e
[157] https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4809014/#:~:text=About%2041.79%25%20of%20the%20GHG,compacting%20and%20the%20curing%20phase
[158] 395,183 kg CO2e per 560,000 sq. meter or 0.7056 kg CO2e per sq. meter
[159] 0.7057 kg CO2e per sq. meter x 2.23 sq. meter excavation area = 1.574 kg CO2e or 0.001574 metric tons CO2e
[160] https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4809014/#:~:text=About%2041.79%25%20of%20the%20GHG,compacting%20and%20the%20curing%20phase
[161] 231,288 kg CO2e per 560,000 sq. meter or 0.4130 kg CO2e per sq. meter
[162] 0.4130 kg CO2e per sq. meter x 2.23 sq. meter excavation area = 0.9210 kg CO2e or 0.000921 metric tons CO2e
[163] https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4809014/#:~:text=About%2041.79%25%20of%20the%20GHG,compacting%20and%20the%20curing%20phase
[164] 34,894 kg CO2e per 560,000 sq. meter or 0.0623 kg CO2e per sq. meter
[165] 0.0623 kg CO2e per sq. meter x 2.23 sq. meter excavation area = 0.139 kg CO2e or 0.000139 metric tons CO2e
[166] https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4809014/#:~:text=About%2041.79%25%20of%20the%20GHG,compacting%20and%20the%20curing%20phase
[167] 21,763 kg CO2e per 560,000 sq. meter or 0.039 kg CO2e per sq. meter
[168] 0.039 kg CO2e per sq. meter x 2.23 sq. meter excavation area = 0.087 kg CO2e or 0.000087 metric tons CO2e
[169] This analysis does not take into account emissions from use of a jackhammer to break up concrete, excavate and refill dirt, remove concrete by dump truck, or additional emissions if crew unable to repair leak in one day and must return.

8) Action taken during anticipated/actual changes to the environment

As proposed, the requirement to conduct immediate and continuous action to repair Grade 2 leaks when "changes to the environment" are anticipated or occur near the leak (i.e., freezing ground, heavy rain, etc.; see § 192.760(c)(5)) is at once too prescriptive and too ambiguous. Too prescriptive in that the rule effectively requires operators to treat every affected leak as a Grade 1 leak, regardless of the leak's repair/replacement schedule or other mitigative actions (such as venting, isolating, or increased monitoring) that the operator may otherwise take to provide equal or greater protection to public safety during such an event. Too ambiguous in that "anticipating" changes to the environment that "may" affect venting or mitigation of gas and "could" allow gas to migrate is too imprecise to provide predictable mitigation of leak risk. As discussed previously, operators must be given latitude to define and respond to environmental changes when they occur, based on their unique geography, climate, proximity to the operator's system, relevant operating history, and other environmental factors. A prudent response is investigation of existing Grade 2 leaks in locations both susceptible and likely to advance in severity with environmental changes and other natural forces (as identified in an operators' DIMP), *whenever those changes occur*.

9) Leak Grading based on human senses

Criteria for classification of Grade 1 leaks should not include human senses. As PHMSA acknowledges on page 31909 of the NPRM, "… human senses such as smell or sight, which are imprecise and substantially limited in their effectiveness." Grading of leaks should be determined by the use of instruments designed and calibrated to identify gas as per the minimum performance standards established in the operator's ALDP. The use of human senses such as smell or sight is limited in effectiveness due to an individual's perspective, open to personal interpretation, subjective, affected by the surrounding environment, and impacted by the overall health and wellness of an individual.

10) Post-repair re-checks

The appropriate timing of a post-leak repair re-check is dependent on whether a repair can reasonably be confirmed to have eliminated the leak. In many scenarios – indeed more instances than described in the NPRM in exempting certain leaks from a post-repair re-check (e.g., above-grade leaks eliminated by lubrication or adjustment) – a 0% gas reading can be made immediately following the repair. The major exception to this is the instance of a below-ground leak which has migrated into and permeated the surrounding soil, such that residual gas readings are evident following the conclusion of the leak repair. In this and only this scenario is it unlikely that an operator can verify that the leak repair resulted in 0% gas readings immediately following the repair, thus necessitating a post-repair re-check to verify elimination of residual gas and confirm the repair has resolved all leakage. Given this scenario, and the singular need to ensure that residual gas has fully dissipated, prescribing a “no sooner than” qualifier for post-repair re-checks is not applicable.

It should be recognized that scenarios in which residual gas readings do not decline are not evidence a repair was inadequate. These persistent readings can be indicative of another leak (or leaks), which may even have occurred after the initial repair was made. Accordingly, the provision stating that a repair is not “complete” until 0% gas readings are achieved is not valid and may create misinterpretations for demonstrating compliance with repair intervals prescribed in § 192.760.

The outcome of post repair re-checks should therefore fall into one of three categories: 1) re-checks finding 0% gas reads (no further action required); 2) re-checks finding gas reads that are lower than previous read (schedule follow-up re-check); or 3) re-checks finding reads greater than (or equal to) previous read (indicative of new or ongoing leakage, grade and schedule reevaluation/repair accordingly). Repairs of pipeline damages caused by 3rd party excavators should clearly not require a re-check.

11) Downgrading leaks

PHMSA has proposed prohibiting an operator’s ability to downgrade a leak unless a temporary or permanent repair has been made. PHMSA states in the NPRM this prohibition would “prevent practices such as downgrading a leak after venting until gas concentration falls below a grade 1 or grade 2 criteria, with an effort to repair the leak itself.”

However, in its proposed rule, PHMSA does not appear to consider the possibility of operator error when grading leaks. The incorrect grading of leaks, without possibility to downgrade, could have significant detrimental impact to an operator. For example, many operators have experienced the scenario where an individual performing leak survey makes the decision to be overly conservative and grades every leak found a Grade 1 leak. The individual may be new in his/her role and lacks confidence in their new position, or it could be that they have trouble accepting responsibility for grading a leak as Grade 3 or Grade 2. The operators then immediately dispatch their own personnel to the found leaks to perform a quality check on the leak grading. Operator personnel typically find many of these purported Grade 1 leaks are actually Grade 2 or, in some cases, Grade 3. Currently, an operator can downgrade the leaks and address the operator error through their Operator Qualification and training program. If an operator was not able to downgrade these leaks, they would be left in a situation where compliance with Grade 1 leak repair timelines would be unachievable.

The Associations recommend adding a second potential scenario for downgrading leaks that accounts for leaks that are erroneously identified as Grade 1. The Associations recognize that this scenario will need to be closely linked to an operator’s Operator

Qualification program found in 49 CFR Subpart N and has suggested regulatory text language to mirror that recognition.

12) Recordkeeping requirements

PHMSA proposes two timelines for the retention of records related to leak survey, leak investigation, leak grading, the monitoring of leaks, the repair or remediation of leaks and leak re-checks: either 5 years or the life of the pipeline. The Associations believe that the regulatory text proposed in the NPRM is confusing and propose clearer, more concise, alternative language for § 192.760(i) - Recordkeeping.

The Associations also recommend that PHMSA extend the record retention requirements for some leak associated records from 5 years to 10 years for transmission and distribution pipelines. Current § 192.1011 requires distribution pipeline operators to maintain "records demonstrating compliance with the requirements of [Subpart P] for at least 10 years." Consistency with record requirements throughout 49 CFR 192 is necessary to eliminate confusion and to reduce the administrative burden on regulated entities.

PHMSA should also consider whether this provision provides redundant and duplicative recordkeeping requirements, which should always be avoided.

13) Evaluation of costs of repairing gas transmission leaks

Given PHMSA's proposal to disallow Grade 3 leak classification on gas transmission pipelines, transmission operators must fix all detectable leaks within six months, if not sooner. The agency has not evaluated the costs of this timeframe in its regulatory impact analysis. The agency should revise its regulatory impact analysis to evaluate the costs of excepting Grade 3 leak classification from transmission pipelines and Type A or Type C regulated gas gathering lines.

Furthermore, the agency's conclusion that the cost of repairing a leak is $5,650, or with follow-up activities, $5,868 per leak, is incorrect. PHMSA bases this calculation on a utility rate case involving a single operator. PHMSA first multiplied the annual transmission mileage by a leak rate of 0.0046 per mile, which the Agency is using as a baseline for the number of total annual leaks. PHMSA then applied a higher average leak rate of 0.0053961 per mile using ALD in order to determine the incremental leak rate. The incremental leaks were then multiplied by the cost of repair of $5868. The Associations believe that this is not an appropriate method for estimating these cost impacts and is an oversimplification of the complexity of repairing leaks, particularly on valves and other above-ground facilities. It should be noted that small leaks on valves, wellhead equipment and other components and vessels, are often difficult to fix and may require a proportionately large extent of the pipeline or facility to be removed from service in order to complete the repair or replacement. Taking pipeline or facility outages to eliminate minor leaks (that can often be measured in bubbles per minute) is not justified. The cost of said leaks cannot be accounted for in PHMSA's leak repair cost averaging. Repairs of leaks on cross country lines (where access and environmental permitting and impact mitigation are major cost drivers) and leaks in city streets and state highway rights-of-way (which require permitting and extensive traffic control or road closures) could be substantially more expensive than $5,868 per leak to repair.

PHMSA should recalculate the cost of leak repair to include the initial investigation of all potential leaks (positive and false positives), account for the cost of investigating each actual leak based on requirements in the NPRM, use more appropriate repair costs for higher cost repairs, and increase the amount of time/labor cost of the leak repair confirmation. Association members developed a four-step process to estimate these costs more accurately:

1. *Investigation of all indications of a leak:* The Associations determined that using a 5 ppm ALD method results in a leak indication rate of 0.078 per mile — including both actual leaks and false indications of a leak. This rate was determined by an operator who had used a 5 ppm sensitivity in previous operational years and tracked both the false positives and actual leaks on their 500 mile system. Applying the same rate and taking 2024 mileage of 308,972 x 0.078 results in 24,100 potential leaks, which all need to be investigated. The Associations believes that each potential leak will result in six hours of a technician's time to investigate each potential leak at a labor rate of $72.61. Therefore, the annual cost for investigation of all potential leaks is over $10.5 million (24,100 x 6 hours x $72.61 starting in 2024).

   However, the Associations also used data provided by a service provider from Europe that specializes in laser-based aerial leak detection for gas pipelines. According to customer feedback using this specific technology, 75% of gas indications were actual leaks, while 25% of leaks were false positives. Therefore, after considering the costs associated with positive leaks identified in the PRIA plus a 25% increase for false positives, the actual cost of indications of potential leaks are calculated in Table 4.

   Technician labor is based on member feedback and includes a $38 hourly rate, $5 equipment use per hour (fuel, maintenance, toll tags, vehicle depreciation), $10 miscellaneous costs (e.g., fire retardant clothing rental, steel toed boots, gloves, tooling, tooling calibration costs, etc.) and 37% benefits loading (health insurance, retirement, life insurance, 401k match, social security, PTO). Total technician costs are $72.61 per hour.

Table 4: Potential Indications of a Leak Using 5ppm ALD Sensitivity

Year	Mileage	LOW Supplier Indication of a leak (ALD positive leaks + 25% false leaks)	HIGH Operator Detection Rate with 5ppm (.078/mile)	LOW Investigation of Indication of Leak (includes 6 hrs. of technician time at $72.61 labor rate) [$M]	HIGH Investigation of Indication of Leak (includes 6 hrs. of technician time at $72.61 labor rate) [$M]
2024	308972.6	2,084	24,100	$.9	$10
2025	311489.8	2,101	24,296	$.9	$11
2026	314007	2,118	24,493	$.9	$11
2027	316746	2,136	24,706	$.9	$11
2028	319485	2,155	24,920	$.9	$11
2029	322224	2,173	25,133	$.9	$11
2030	324963	2,192	25,347	$1.0	$11
2031	327702	2,210	25,561	$1.0	$11
2032	330570	2,230	25,784	$1.0	$11
2033	333438	2,249	26,008	$1.0	$11
2034	336306	2,268	26,232	$1.0	$11
2035	339174	2,288	26,456	$1.0	$12
2036	342042	2,307	26,679	$1.0	$12
2037	344910	2,326	26,903	$1.0	$12
2038	347778	2,346	27,127	$1.0	$12

2. *Investigation of leaks:* As noted above, PHMSA should use its information gathering authority to solicit actual data from operators. However, assuming that PHMSA baseline and incremental leak rate are relatively accurate (.0046 baseline and 0.0053961 with ALD methods), the incremental leaks are approximately 246 in 2024 and increases by year based on mileage adjustments. To investigate a leak based on requirements in the NPRM, the Association had an operator pull the cost to conduct the necessary metallurgical lab work which was $5,865 per leak. The total to write the investigation report would require 12 hours of staff time at a blended rate of $76.63 (which is outlined in Table 18 of the PRIA for reporting purposes). Total cost of incremental leaks x $5,865 + leaks x $919.56 equates to $2.9 million (2024).

Table 5: Investigations of a leak

Year	85% Baseline Leaks (.0046/mile)	100% Leaks with ALD (.0053961/mile)	Incremental Leaks	Investigation of Leak ($5865/Investigation + 3 people x 4 hrs. at $76.63) [$M]
2024	1421	1667	246	$2
2025	1433	1681	248	$2
2026	1444	1694	250	$2
2027	1457	1709	252	$2
2028	1470	1724	254	$2
2029	1482	1739	257	$2
2030	1495	1754	259	$2
2031	1507	1768	261	$2
2032	1521	1784	263	$2
2033	1534	1799	265	$2
2034	1547	1815	268	$2
2035	1560	1830	270	$2
2036	1573	1846	272	$2
2037	1587	1861	275	$2
2038	1600	1877	277	$2

3. *Repairing leaks:* Very few operators have readily available data on the cost per repair for a leak. Given the deadline to provide these comments, the Association was not able to gather empirical data from multiple operators. However, PHMSA has information gathering authority which it should use to do just that – gather empirical data from across the industry so that the revised PRIA is based on actual costs.

   For the purposes of this analysis and to demonstrate the obvious errors in the PHMSA calculations, the Associations made conservative assumptions. While these assumptions are not concrete enough to meet the cost/benefit requirements of the Pipeline Safety Act, they do demonstrate that PHMSA's calculated cost per leak is far too low. One of the conservative assumptions the Association made is that of the incremental leaks found in part two of this process, the majority, 70 percent, would be at the cost currently included in the PRIA of $5,650 per leak. The leaks that would likely fall into this low-cost category are minor leaks that could be repaired with a grease gun or with limited equipment, such as a wrench—essentially leaks that could be fixed within a day or two. The Associations then assumed that 20 percent of leaks would require a medium cost to repair of $20,000. Medium cost repairs would include replacing a small diameter valve for example, which is easy to isolate. Lastly, the Associations assumed that approximately 10 percent of leaks would require a higher cost to repair, such as a valve packing repair with isolation of a mainline valve segment and blowdown mitigation. The cost for these repairs is typically over $100,000, without considering the service disruption impacts which should be included in PHMSA's subsequent analysis. Multiplying the low, medium, and high leak by the repair costs equates to over $4 million annually (excluding costs of service disruptions). Using these assumptions, the Associations recalculated the following values which demonstrate that PHMSA's calculations were erroneous.

Table 6: Low, Medium, High Repair Costs

Year	Low ($M)	Medium ($M)	High Cost ($M)	Total Repair ($M)
2024	$1	$1	$2	$4
2025	$1	$1	$2	$4
2026	$1	$1	$2	$4
2027	$1	$1	$3	$5
2028	$1	$1	$3	$5
2029	$1	$1	$3	$5
2030	$1	$1	$3	$5
2031	$1	$1	$3	$5
2032	$1	$1	$3	$5
2033	$1	$1	$3	$5
2034	$1	$1	$3	$5
2035	$1	$1	$3	$5
2036	$1	$1	$3	$5
2037	$1	$1	$3	$5
2038	$1	$1	$3	$5

4. *Post-repair re-checks:* The Associations calculate the post repair re-checks at the technician rate in step 1 of $72.61 per hour and that the confirmation process will take approximately 4 hours of time.

Table 7: Post Repair Confirmation Labor Costs

Year	Post Repair Confirmation (4 hours at $72.61 labor rate) [$M]
2024	$.07
2025	$.07
2026	$.07
2027	$.07

2028	$.07
2029	$.07
2030	$.08
2031	$.08
2032	$.08
2033	$.08
2034	$.08
2035	$.08
2036	$.08
2037	$.08
2038	$.08

Combining the costs in the 4-step process results in an annual cost far in excess of PHMSA's estimated cost of $1.5 million per year.

Table 8: Total cost of performing leak repairs

Year	LOW: Step 1 Indication of Leak	HIGH: Step 1 Indication of Leak	Step 2 Investigation of Leak	Step 3 Repairing Leaks	Step 4 Post Repair Re-check	Low: Total Leak Repair Process Cost ($M)	HIGH: Total Leak Repair Process Cost ($M)
2024	$.9	$10	$2	$4	$.07	$7	$17
2025	$.9	$11	$2	$4	$.07	$7	$17
2026	$.9	$11	$2	$4	$.07	$7	$17
2027	$.9	$11	$2	$5	$.07	$7	$17
2028	$.9	$11	$2	$5	$.07	$7	$17
2029	$.9	$11	$2	$5	$.07	$7	$17
2030	$1.0	$11	$2	$5	$.08	$7	$18
2031	$1.0	$11	$2	$5	$.08	$7	$18
2032	$1.0	$11	$2	$5	$.08	$8	$18
2033	$1.0	$11	$2	$5	$.08	$8	$18
2034	$1.0	$11	$2	$5	$.08	$8	$18
2035	$1.0	$12	$2	$5	$.08	$8	$18
2036	$1.0	$12	$2	$5	$.08	$8	$18
2037	$1.0	$12	$2	$5	$.08	$8	$19
2038	$1.0	$12	$2	$5	$.08	$8	$19
					3% Total	**$89**	**$217**
					7% Total	**$68**	**$171**
					3% Annualized	**$5.9**	**$14.5**
					7% Annualized	**$4.5**	**$11.4**

- ***Note:*** Even with barring the above identified inaccuracies, PHMSA's cost/benefit analysis shows negative net benefits for transmission "in every scenario" and only shows positive net benefits for distribution when assuming that Weller's inaccurate data is correct. EPA's recent GHG reporting proposed rule states that Lamb is preferred to Weller, which suggests that PHMSA's cost/benefit analysis for distribution will also result in zero or net-negative benefits, even when dismissing the above identified inaccuracies.

14) Compressor Station Exception

PHMSA is proposing to add an exception from the requirements for conducting right-of-way (ROW) patrols and leak surveys, grading and repairing leaks, implementing advanced leak detection programs, and the qualification of leak survey personnel for compressor stations on a gas transmission or gathering pipeline if:

> (1) The facility is subject to methane emission monitoring and repair requirements under either:
>
> > (i) 40 CFR part 60, subparts OOOOa or OOOOb; or
> >
> > (ii) an EPA-approved State plan or Federal plan which includes relevant standards at least as stringent as EPA's finalized emissions guidelines in 40 CFR part 60, subpart OOOOc;
>
> (2) The facility is within the first block valve entering or exiting the compressor station covered by the emergency shutdown system as required in § 192.167 for station isolation from the pipeline; and

The Associations support the proposed exception for compressor station facilities on transmission and gathering lines that are subject to EPA's methane emission monitoring and repair requirements in Subpart OOOOa and, if finalized, Subparts OOOOb and OOOOc. EPA's comprehensive regulations render compliance with PHMSA's requirements for ROW patrolling, leak surveying, leak grading and repairing, advanced leak detection programs, and qualification of leak survey personnel unnecessary.

(i) Scope of Exception

PHMSA should ensure that the applicability of the exception aligns in all respects with the scope of EPA's regulations. There is no reason for PHMSA to apply its LDAR regulations to facilities at compressor stations that are subject to EPA's methane emission monitoring and reporting requirements. Doing so would only create unnecessary overlap and jurisdictional conflicts that do not promote public safety or the protection of the environment.

The Agency should clarify and expand the proposed exception in Section 192.703(d) to include facilities subject to state regulations. In proposed Section 192.703(d)(1)(ii), PHMSA provides that an operator will not need to comply with Sections 192.703(c), 192.705, 192.706, 197.760(a)-(h), 192.763, and 192.769 if the compressor station is subject to methane emission monitoring and repair requirements under EPA's OOOOa, OOOOb, or an EPA approved state or federal plan that is as stringent as the anticipated requirements in OOOOc.[170] PHMSA should clarify the exception in 192.703(d)(1)(ii) to say "an EPA federal plan or EPA-approved state plan implementing the emissions guidelines in 40 CFR 60, subpart OOOOc. This is necessary because an EPA-approved state plan is allowed deviate from the emissions guidelines based on factors such as remaining useful life. PHMSA should also include state methane emission monitoring and repair requirements until a time that they are part of an EPA-approved plan. Numerous operators are subject to various state emission monitoring and repair regulations. PHMSA acknowledges the existence of these requirements in the preamble of the NPRM.[171] For efficiency and consistency purposes, PHMSA should also incorporate facilities that are subject to these state regulations in its Section 192.703(d) exception.

(ii) Applicability of recordkeeping provision

PHMSA's proposed Section 192.703(d)(3) provides that while an operator's compressor station may be exempted from PHMSA leak grading and repair requirements,[172] it would still need to maintain repair records for the life of the facility. If the compressor station is exempted from the leak grading and repair requirements in Sections 192.706(a)-(h), it should also be exempt from recordkeeping requirements in Section 192.706(i). Without further explanation from the agency, the Associations can only assume that PHMSA is expecting those operators with compressor stations exempted from PHMSA regulations to maintain its OOOO repair records for PHMSA purposes. This is duplicative and unnecessary. PHMSA has no legal authority to enforce EPA's regulations, and there is no reason for the Agency to impose a separate requirement that these records be maintained to qualify for the exception.

(iii) Impact of finalization of EPA Rule

PHMSA should reevaluate its intentions to require operators of compressor stations to comply with the NPRM until OOOOb and OOOOc are finalized. PHMSA's position on whether pipeline facilities subject to the anticipated OOOOb and OOOOc requirements will qualify for the exception in Section 192.703(d) is confusing. The agency states in the preamble that "[i]n the event that EPA's proposed regulations at subparts OOOOb and OOOOc are not in effect because they have not yet been finalized or for any other reasons, the proposed exception would not apply and the leak detection, grading, and repair requirements proposed herein would apply to gas transmission and gas gathering compressor station facilities."[173] The agency also provides in footnote 245 that "should proposed

[170] Proposed Section 192.703(d)(1)(ii).
[171] 88 Fed. Reg. at 31,916-31,919.
[172] *See* Proposed Section 192.703(d) referencing Sections 192.760(a)-(h).
[173] 88 Fed. Reg. at 31,939.

subparts OOOOb and OOOOc not be finalized, only gas transmission compressor and gas gathering boosting stations subject to 40 C.F.R. part 60, subpart OOOOa would be eligible for the exception proposed in this NPRM."[174] However, in the PRIA, PHMSA states that "*[a]lthough PHMSA assessed an alternative where no such exemption would be provided, PHMSA did not propose that alternative to avoid duplicative regulation of those facilities.*"[175]

Operators should not be required to create a new program in compliance with PHMSA's leak detection and repair requirements only to pivot to the EPA requirements when they are finalized. This position is not reasonable, cost-effective, or practical. Instead, the Agency should provide a three-year effective date for the final rule in this proceeding. A longer effective date would allow those facilities that are covered by proposed Section 192.703(d) to accommodate any delays in finalizing the EPA rule and prevent duplicative efforts.

If PHMSA proceeds with requiring operators of these facilities to comply with the Final Rule first and then subsequently OOOOb or OOOOc, the agency will need to incorporate these costs into its Final Regulatory Impact Analysis. In the PRIA, PHMSA examined these costs but framed them up as a regulatory alternative that the agency chose to not select.[176] This is confusing because in the NPRM, the agency has clearly chosen to proceed with applying its proposed requirements to facilities subject to OOOOb or OOOOc, if the EPA rules are not finalized at the time of PHMSA's publication.[177] The agency's estimate of the costs of eliminating the exception are $11.9 million per year. However, it is not clear if that cost estimate also included the effort to move these facilities to an EPA directed program once the OOOOb and c rules are finalized.

The Associations recommend the new 192.760 be retitled so that it correctly captures the relationship between leak investigation, leak grading, and the response timeframes attached to remediation, which could be repair or pipe replacement. Suggested changes are listed below[178]:

[174] 88 Fed. Reg. at 31,939, fn. 245.
[175] PRIA, at 20.
[176] *Id.*, at 7 ("In the event EPA does not finalize the proposed requirements, PHMSA *could* proceed with setting equivalent requirements for gas transmission compressor stations and gathering and booting stations by eliminating the exemption"). *See also,* PRIA at 20 ("Although PHMSA assessed an alternative where no such exemption would be provided, PHMSA did not propose that alternative to avoid duplicative regulation of those facilities.")
[177] 88 Fed. Reg. 31,890, at 31,939; *See also,* 88 Fed. Reg. 31,939, fn. 245.
[178] All regulatory text recommended by the Associations in these comments use the following color scheme: blue underline for PHMSA's proposed additions supported by the Associations; ~~red strike-through~~ for PHMSA's proposed deletions supported by the Associations; purple underline (or ~~purple strike-through~~) for revisions suggested by the Associations.

§ 192.760 Leak grading and repair/remediation.

(a) *General.* Each operator must have and follow written procedures for grading and repairing or remediating leaks that meet or exceed the requirements of this section.

(1) These requirements are applicable to leaks found on all portions of a gas pipeline including, but not limited to, line pipe, valves, flanges, meters, regulators, tie-ins, launchers, and receivers.

(2) The leak grading and repair ~~procedure~~ methods must prioritize leak repairs/remediation by the hazard to public safety and ~~the~~ environmental significance ~~environment~~.

(3) Each leak must be investigated and a leak grade established as part of the leak investigation process.~~immediately and continuously until a leak grade determination has been made.~~

(b) *Grade 1 leaks.*

(1) A grade 1 leak ~~is any leak that constitutes an existing or probable hazard to persons or property or a grave hazard to the environment is environmentally significant. A grade 1 leak~~ includes a leak with any of the following characteristics:

(i) A hazardous leak, as defined in § 192.3. ~~ny leak that, in the judgment of operating personnel at the scene is regarded as an existing or probable hazard to public safety or a grave hazard to the environment~~;

(ii) Any amount of escaping gas has ignited;

(iii) Any indication that gas has migrated into a building, under a building, or into a tunnel;

(iv) For an underground leak, ~~A~~any reading of gas at the outside wall of a building, or areas where gas could migrate to an outside wall of a building;

(v) Any reading of 80% or greater of the LEL (60% for LPG systems) in ~~a confined space~~ an enclosure;

(vi) Any reading of 80% or greater of the LEL (60% for LPG systems) in a substructure, (including gas associated substructures) from which any gas could migrate to the outside wall of a building

(vii)~~ Any leak that can be seen, heard, or felt; o~~

~~(viii)~~ Any leak defined as an incident in § 191.3.

(2) An operator must promptly repair a grade 1 leak and eliminate the hazardous conditions by taking immediate and continuous action by operator personnel at the scene. Immediate action means the operator will begin instant efforts to remediate and repair the leak upon detection and to eliminate any hazardous conditions caused by the leak. Continuous means that the operator must maintain on-site remediation efforts until the leak repair has been completed. This may require one or more of, but not limited to, the following actions be taken without delay:

(i) Implementing an emergency plan pursuant to § 192.615;

(ii) Evacuating premises;
(iii) Blocking off an area;
(iv) Rerouting traffic;
(v) Eliminating sources of ignition;
(vi) Venting the area by removing manhole covers, bar holing, installing vent holes, or other means;
(vii) Stopping the flow of gas by closing valves or other means; or
(viii) Notifying emergency responders.

(c) *Grade 2 leaks.*

(1) A grade 2 leak~~ constitutes a probable future hazard to persons or property or a significant hazard to the environment, and~~ includes any leak (other than a grade 1 leak) with any of the following characteristics:

(i) A reading of 40% or greater of the LEL under a sidewalk in a wall-to-wall paved area that does not qualify as a grade 1 leak;
(ii) A reading at or above 100% of LEL under a street in a wall-to-wall paved area that has gas migration and does not qualify as a grade 1 leak;
(iii) A reading between 20% and 80% of the LEL in ~~a confined space~~ an enclosure;
(iv) A reading less than 80% of the LEL in a substructure (other than gas associated substructures) from which gas could migrate;
(v) A reading of 80% or greater of the LEL in a gas associated substructure from which gas could not migrate;
~~(vi) Any reading of gas that does not qualify as a grade 1 leak that occurs on a transmission pipeline or a Type A or Type C regulated gas gathering line;~~
(vi)~~(vii) Any leak with a leakage rate of 10 cubic feet per hour (CFH) or more that does not qualify as a grade 1 leak;~~ Is of sufficient magnitude to pose significant potential harm to the environment, applying one of the following criteria as determined by the operator:

(A) estimated leakage rate of 10 cubic feet per hour (CFH) or more, as indicated by suitable technology; or
(B) estimated ‘‘leak extent’’ (land area affected by gas migration) of 2,000 square feet or greater; or
(C) an alternative method for determining environmental significance of a leak.

~~(viii) Any leak of LPG or hydrogen gas that does not qualify as a grade 1 leak;~~ or
~~(ix)~~(vii) Any leak that, in the judgment of operating personnel at the scene, is of sufficient magnitude to justify scheduled repair within ~~six~~ 12 months or less.

(2) ~~An operator must schedule repair based on the severity or likelihood of hazard to persons, property, or the environment.~~ A grade 2 leak must be

repaired/remediated within ~~six~~ 12 months of detection except as described below, or unless a shorter repair deadline is required by the operator's procedures, integrity management program, or paragraphs (c)(3) through ~~(6)~~(4) of this section. The operator must reevaluate each grade 2 leak at least once every ~~30 days~~ 6 months until it is repaired.

(i) An operator must complete repair of known grade 2 leaks existing on or before [effective date of the final rule] before [date ~~1 year~~ 36 months after the effective ~~publication~~ date of the final rule] unless an extension request has been approved under (h).

(ii) A grade 2 leak may be evaluated in accordance with paragraph (c)(2) of this section and repairs postponed if the segment containing the leak is scheduled for replacement, and is replaced, within 5 years of detection of the leak.

(3) The operator must complete repair of any grade 2 leak on a gas transmission or Type A gathering pipeline, each located in an HCA, Class 3 or Class 4 location, within ~~30 days~~12 months of detection. If repair cannot be completed within ~~30 days~~ 12 months due to permitting requirements or parts availability, the operator must ~~take continuous action to monitor and repair the leak~~ reevaluate each grade 2 leak at least once every 45 days until it is repaired/remediated.

~~(4) Each operator's operations and maintenance procedure must include a methodology for prioritizing the repair of grade 2 leaks, including criteria for leaks that warrant repair within 30 days of detection pursuant to § 192.760(c). Grade 2 leaks with a repair deadline of less than 30 days must be reevaluated at least once every 2 weeks until the repair is complete. This methodology must include an analysis of, at a minimum, each of the following parameters:~~

~~(i) The volume and migration of gas emissions;~~

~~(ii) The proximity of gas to buildings and subsurface structures;~~

~~(iii) The extent of pavement; and~~

~~(iv) Soil type and conditions, such as frost cap, moisture, and natural venting.~~

~~(5)~~ (4) Each operator must ~~take immediate and continuous action to complete repair of~~ investigate a known below ground grade 2 leak ~~and eliminate the hazard~~ when the operator becomes aware of freezing ground, heavy rain, flooding, new pavement, or other changes to the environment ~~are anticipated or occur~~ near ~~an~~ the existing grade 2 leak that may affect the venting or migration of gas and could allow gas to migrate to the outside wall of a building.

~~(6) An operator must complete repair of known grade 2 leaks existing on or before [insert effective date of the final rule] before [insert date 1 year after the publication date of the final rule].~~

(d) *Grade 3 leaks.*

(1) A grade 3 leak is any leak that does not meet the criteria of a grade 1 or grade 2 leak. In order to qualify as a grade 3 leak, none of the criteria for grade 1 or 2 leaks must be present. Grade 3 leaks may include, but are not limited to, leaks with the following characteristics:

(i) A reading of less than 80% of the LEL in gas associated substructures from which gas is unlikely to migrate; or

(ii) Any reading of gas under pavement outside of a wall-to-wall paved area where gas is unlikely to migrate to the outside wall of a building; or

(iii) A reading of less than 20% of the LEL in ~~a confined space~~ an enclosure.

(2) A grade 3 leak must be repaired within ~~24~~ 36 months of detection, except as described below:

(i) A grade 3 leak known to exist on or before [effective date of the final rule] must be repaired prior to [date 3 years after the effective ~~publication~~ date of the final rule] unless an extension request has been approved under (h).

(ii) A grade 3 leak may be evaluated in accordance with paragraph (d)(3) of this section and repairs postponed if the segment containing the leak is scheduled for replacement, and is replaced, within ~~five~~10 years of detection of the leak.

(3) Each operator must reevaluate each grade 3 leak at least once every 12~~six~~ months until repair/remediation of the leak is complete.

(e) *Post-repair* ~~*inspection*~~ *re-check.*

~~(1) A leak repair is considered to be complete when an operator obtains a gas concentration reading of 0% gas at the leak location after a permanent repair.~~

(1)~~(2)~~ An operator must conduct a post-repair leak ~~inspection~~ re-check ~~at least 14 days after but~~ no later than 30 days after the ~~date of the~~ repair ~~to determine if the repair was complete,~~ if 0% gas concentration readings cannot be achieved after repair due to residual gas in the soil.

(2)~~(3)~~ If a post-repair ~~inspection~~ re-check shows a gas concentration reading greater than 0%, the ~~repair is not complete,gas~~ operator must take the following actions:

(i) If the re-check shows a gas concentration lower than the most recent read, the operator must perform a re-check within 30 days and continue re-checking at least once every 30 days until there is a gas concentration reading of 0%.

(ii) If the re-check shows a gas concentration higher than (or equal to) the most recent read, the operator must investigate and repair or grade the leak according to paragraph § 192.760(b), § 192.760(c), or § 192.760(d).

~~i) if the operator's post repair re-check finding 0% gas reads (no further action required); 2) re-checks finding gas reads that are lower than previous read (schedule follow-up re-check); or 3) re-checks finding reads greater than (or equal to) previous read (indicative of new or ongoing leakage, grade and schedule reevaluation/repair accordingly). (i) If the post repair inspection finds gas concentrations or migration indicating that the potential for a grade 1 or grade 2 condition leak exists, the operator must re-inspect the repair and take immediate and continuous action to eliminate the hazard and complete repair;~~

~~(ii) If the operator's post repair inspection does not find a gas concentration reading of 0% at the leak location, and a grade 1 or grade 2 condition does not exist, then the operator must remediate the repair and re-inspect the leak within 30 days and continue reevaluating the leak at least once every 30 days until there is a gas concentration reading of 0%. Leak repair must be complete within the repair deadline for a grade 3 leak under § 192.760(d)(2), or for a downgraded leak, the repair deadline under § 192.760(g).~~

(3)~~(4)~~ A post repair ~~inspection~~ re-check is not required for: (i) any leak that is eliminated by routine maintenance work—such as adjustment or lubrication of aboveground valves, or tightening of packing nuts on valves with seal leaks;~~—and is~~ (ii) a grade 3 leak or one that occurs on an aboveground pipeline facility~~.~~; (iii) repairs for excavation damages; (iv) remediation of leak involving pipeline replacement; or (v) remediation where the leaking pipeline was abandoned.

(f) *Upgrading leak grades.*

If at any time an operator receives information that a higher-priority grade condition exists in connection with a previously graded leak, the operator must upgrade that leak to the higher-priority grade. When an operator upgrades a leak to a higher-priority grade, the time period to complete the repair is the earlier of either the remaining time based on its original leak grade or the time allowed for repair under its new leak grade measured from the time the operator received the information that a higher priority grade condition exists.

(g) *Downgrading leak grades.*

A leak may not be downgraded to a lower priority leak grade unless:

(i) A~~a~~ temporary repair to the pipeline has been made or a permanent repair was attempted but gas was detected during the post-repair re-check ~~inspection~~ under paragraph (e) of this section, or

(ii) The leak was initially graded incorrectly. Operators must address any additional necessary actions through Subpart N for individuals that incorrectly grade leaks.

In these cases~~this case~~, the time period for repair is the remaining time allowed for repair under its new grade measured from the time the leak was first detected.

(h) *Extension of leak repair/remediation*.
An operator may request an extension of the leak repair deadline requirements for an individual grade 2 leak or grade 3 leak with advance notification to and no objection from PHMSA pursuant to § 192.18. The operator's notification must show that the delayed repair timeline would not result in an increased risk to public safety, as well as that either the required repair deadline is impracticable, ~~or~~ that remediation within the specified time frame would result in the release of more gas to the environment than would occur with continued monitoring, or that a replacement project is pending and would negate the need to make any repair. The notification must include the following:

(1) A description of the leaking facility including the location, material properties, the type of equipment that is leaking, and the operating pressure;
(2) A description of the leak and the leak environment, including gas concentration readings, leak rate if known, class location, nearby buildings, weather conditions, soil conditions, and other conditions that could affect gas migration, such as pavement;
(3) A description of the alternative Repair/remediation schedule and a justification for the same; and
(4) Proposed emissions mitigation methods, monitoring, and repair schedule.

(i) *Recordkeeping.*

(1) Records ~~of the complete history of the investigation and grading of each leak must be retained for 5 years after the final post repair inspection is completed under paragraph (e) of this section. These records include all records~~ documenting the leak grading~~, monitoring, inspections~~ re-checks completed under paragraph (e) of this section, upgrades, and downgrades must be retained for 5 years after final post-repair re-check.
(2) Records of the ~~detection, remediation, and repair of the leak must be retained for the life of the pipeline. This must include~~ the date, location, and description of each leak detected, and the date and repair or remediation method applied ~~of the same, made on the pipeline.~~must be retained for the life of the pipeline for gas transmission and gas distribution pipelines, unless a shorter timeline is prescribed by § 192.709.

§ 192.703 General.

* * * * *

(c) ~~Hazardous~~ ~~L~~leaks must be graded and repaired ~~promptly~~ in accordance with the requirements in § 192.760.

(d) Compliance with §§ 192.703(c), 192.705 for patrols, 192.706 for leakage surveys, 192.760(a) through (h) for leak grading and repair, 192.763 for advanced leak detection programs, and 192.769 for qualification of leakage survey personnel, is not required for a compressor station on a gas transmission or gathering pipeline if:

(1) The facility is subject to methane emission monitoring and repair requirements under either:

(i) 40 CFR part 60, subparts OOOOa or OOOOb; or

(ii) an EPA-approved State plan or Federal plan which includes relevant standards at least as stringent as EPA's finalized emissions guidelines in 40 CFR part 60, subpart OOOOc;

(2) The facility is within the first block valve entering or exiting the compressor station covered by the emergency shutdown system as required in § 192.167 for station isolation from the pipeline~~; and~~

~~(3) Repair records are maintained for the life of the facility in accordance with § 192.760(i).~~

C. Advanced Leak Detection Programs (ALDP)—§ 192.763

The Associations support the codification of minimum sensitivity capabilities of instruments and technologies as part of an advance leak detection program. This approach will help support fit-for-purpose use of technologies and practices that ensure leak detection is performed with the appropriate equipment and qualified personnel. The associations also support PHMSA's understanding of the importance of affording operators the flexibility to select equipment and technology that is most appropriate for its operational needs and the uniqueness of its pipeline system. The associations believe mandating use of the "newest" or "most sensitive" technology available is inappropriate for an adaptable, practicable, and effective Advanced Leak Detection Program (ALDP). ALDP must not be overly focused on novel technologies over a more holistic approach used in detecting, investigating, and repairing leaks that also takes into consideration the potential impact on ratepayers.

However, the Associations are deeply concerned with some of the proposed requirements in § 192.763. It is critical for PHMSA to promulgate a regulation that does not impose burdensome and arbitrary requirements on instrument sensitivity and measurement techniques. While operators should be encouraged to implement technologies that are proven to be effective, there should not be an assumption that traditional leak survey methods have become ineffective at identifying leaks, particularly those that represent a risk to public safety. Leak surveys performed on foot and by vehicle with traditional equipment and associated detection thresholds and procedures have proven effective in helping the industry achieve a largely favorable safety performance based on the significant incident data collected annually by PHMSA.

PHMSA is also reminded that several requirements being proposed for an ALDP have been applied on some scale, voluntarily by operators in the detection and investigation of leaks for years. This includes utilizing advanced technologies, enhancing procedures for performing leak surveys, and accelerating leak survey frequencies based on material type and geographic location. These activities have frequently been incorporated in an operator's applicable DIMP and/or TIMP plan as preventive and mitigative measures to reduce risk.

1) Instrument sensitivity

Minimum sensitivity of leak detection equipment is currently proposed in § 192.763(a)(1)(ii) as 5 parts per million (ppm) for each gas being surveyed, pinpointed, investigated, or inspected.[179] The Proposed Rule would adopt this threshold based on the notion that unidentified handheld or mobile equipment can detect methane emissions less than 5 ppm. In addition, the proposed rule fails to distinguish process differences and associated fit-for-purpose thresholds in performing leakage surveys versus other O&M leak detection activities. This 5 ppm sensitivity is also adopted as one of the variables defined in the minimum performance standard proposed in § 192.763(a)(1)(iii).

While the rulemaking docket contains vendor promotional materials and records of vendor meetings with PHMSA where the vendors made claims about the capabilities of their equipment, there is no documentation to indicate that PHMSA has actually tested or otherwise verified these claims in order to establish any comprehensive technical basis for the 5 ppm threshold. The docket does include a "Technical Report" by Highwood Emissions Management, PHMSA-2021-0039-0011, purporting to provide a literature review of methane detection equipment. However, nothing in that report discusses detection limitations for any particular technology or provides any basis for the proposed minimum sensitivity criteria.

In any case, the proposed 5 ppm minimum sensitivity criterion, universally applied to all aspects of leak detection, is problematic. In addition, the 5 ppm sensitivity threshold is inappropriate for leak survey using mobile, aerial, and satellite-based platforms, which by their nature are intended to find higher concentrations of gas at significantly greater distances, before confirming with more sensitive equipment. Notwithstanding PHMSA's caveat in § 192.763(a)(1)(iii)(B) that the mobile, aerial, and satellite-based platforms be used "in conjunction with hand-held equipment," it is not clear how operators would demonstrate that leak indications registering gas concentrations as little as 5 ppm were first detected by their mobile, aerial, or satellite-based equipment, given the lower sensitivities that these platforms necessarily employ. Parts per million is a point source unit of measurement that indicates how much gas is present at a specific location. It is not useful when attempting to measure the concentration of gas remotely or over a large area at one time.

The Associations are also concerned about the apparent presumption that all leak detection processes are similar in nature, regardless of leakage origin. Investigative

[179] 88 Fed. Reg. at 31,932.

techniques vary depending on the leak determination activity being performed. Investigative techniques vary depending on the leak determination activity being performed. For example, conducting leak surveys and investigations for interior jurisdictional piping verses exterior subsurface piping may require different instrument sensitivity capabilities, measurement techniques, and investigative procedures. It is critical that the appropriate instruments, investigation procedures, training and qualifications are fit-for-purpose considering the variables in performing these functionally-specific activities. Instruments for leak surveys incorporate different sensor types relative to other leak detection processes, depending on the practical application of the equipment and site-specific conditions. The most sensitive technologies are used for leak surveys of buried outdoor piping. High sensitivity thresholds (ppm) are required to compensate for a variety of environmental variables resulting in diluted gas concentrations outdoors, as well as reaction with the soil and other subsurface variables affecting gas migration patterns.

In contrast, leak investigation techniques – including installation of bar holes and the analysis of gas concentrations that are present (or accumulate) therein – are typically effective in the percent-LEL range. Leak investigation and survey of jurisdictional indoor piping – where the survey environment is not affected by variables such as wind/soil diffusion and gas migration patterns – is another scenario in which the fit-for-purpose detection threshold is in the percent-LEL range. Some operators have also deployed advanced fixed-sensor technologies for continuous monitoring surveys of jurisdictional indoor piping at these sensitivity thresholds. These devices and systems are designed and installed to current industry standards specified by the National Fire Protection Agency[180] and Underwriters Laboratory Standards for Safety[181] and are designated as fit-for-service to alarm at 10% LEL detection threshold and lower, with a low-end sensitivity of 1% LEL (i.e., 500 ppm). These disparate methods and technologies make it inappropriate to codify a minimum sensitivity requirement for equipment used in leak pinpointing and investigation activities.

While it may seem counterintuitive, if the instrument threshold detection capability is too low (i.e., too sensitive), it may impede leak detection in the presence of a background combustible gas concentration at the parts per million level, a copy of the GTI Study is attached as Appendix J.[182] The device may trigger a false alarm when the conditions are only slightly above background. For example, using leak survey equipment with a parts-per-million detection thresholds for indoor piping may hinder an effective and efficient leak survey process. Instrument sensitivity requirements should consider a fit-for-service approach which includes allowing use of conventional portable combustible gas indicators

[180] National Fire Protection Agency, NFPA 715 Installation of Fuel Gases Detection and Warning Equipment.
[181] Underwriters Laboratories, UL 1484 Standard for Residential Gas Detectors and UL 2075 Standard for Gas and Vapor Detectors and Sensors.
[182] Gas Technology Institute, "Leak Survey Equipment Considerations for NY Operations Development of a Regulatory Conformance and Technology Applicability White Paper" (May 2016).

(CGIs) leak solution or bubble testing (i.e., "soap testing") for interior and exterior above ground leak investigations.

2) ***Inconsistency with EPA requirements***

Furthermore, the 5 ppm sensitivity that PHMSA has proposed is inconsistent with existing EPA requirements. EPA defines a leak from a "fugitive emission component" (i.e., valve, connector, pressure relief device, open-ended line, flange, cover, and closed vent system) at a compressor station as "an instrument reading of 500 parts per million (ppm) or greater" using EPA's reference Method 21 for instrument LDAR monitoring.[183] Leaks from equipment within process units at onshore natural gas processing plants are defined differently and range from 500 to 10,000 ppm.[184] PHMSA notes that it chose 5 ppm because it is a "protective threshold of detection sensitivity" compared to EPA's standard of 500 ppm and that 500 ppm represents 1% of the lower explosive limit of methane gas.[185] PHMSA provided no technical basis for the 0.01% threshold, and it is unclear why PHMSA chose the threshold. Congress directed PHMSA "to conduct leak detection and repair programs . . . to protect the environment."[186] As stated earlier, the Associations recommend that PHMSA consider the EPA methane rule matrix when identifying the appropriate sensitivity threshold. EPA's most stringent regulatory definition of a leak is two orders of magnitude higher than PHMSA's proposed minimum sensitivity. PHMSA's blanket 5 ppm proposal exceeds Congress' mandate in section 113, and would impose significant burdens on pipeline operators with little to no associated environmental benefit.

3) ***A significant number of false positives result from inappropriate sensitivity requirements***

When selecting a performance standard for leak detection for transmission and distribution pipelines, the agency should account for the fact that too restrictive of a performance standard will likely lead to numerous false positives. The Agency has not accounted for the resources that are typically spent on responding to indications of a leak to determine if it is truly a natural gas leak or alternatively, decayed matter from natural sources. One INGAA member deployed the 5 ppm sensitivity level for leak survey of certain areas of its interstate transmission pipeline system. It found 39 leaks indications with this sensitivity level; upon further investigation, 36 were determined to be false. Operators will need to extend resources to investigate each and every indication, and PHMSA should acknowledge that (particularly for mobile, aerial, and satellite platforms) prescribing a minimum instrument sensitivity that is too restrictive is not beneficial.

---

[183] 40 CFR § 60.5397a(a)(1).
[184] 40 CFR §§ 60.482-2a-60.482-11a.
[185] 88 Fed. Reg. at 31,933. PHMSA also acknowledged that EPA's 500 ppm standard is "1% of the lower explosive limit of methane gas" which calls into question why 5 ppm is necessary to be a protective threshold.
[186] 49 U.S.C. § 60102(q)(1)(B).

4) Use of EPA-approved methods for above-ground sources

EPA and state programs have robust requirements to regulate methane leaks in areas within the fence line. As PHMSA acknowledges in the NPRM, EPA requires the "repair of all leaks visible with an OGI [optical gas imaging] device or that produce an instrument reading of 500 ppm or greater."[187] PHMSA also confirms that "OGI cameras…are commonly used for fugitive emissions monitoring at LNG plants, compressor stations, and other facilities."[188] However, PHMSA proposes to require leakage surveys on valves, flanges, pipeline tie-ins, and ILI launcher and receiver facilities using the equipment that can meet a minimum sensitivity of 5 ppm.[189] This sensitivity requirement may preclude the use of OGI cameras. PHMSA should capitalize on the benefit of existing EPA regulations and allow operators to use OGI devices or an equivalent for a consistent and efficient regulatory program.

To resolve its concerns, the Associations propose a multi-tiered basis for establishing minimum sensitivity capabilities of leak survey equipment in § 192.763(a)(1)(ii):

- 5 ppm for hand-held equipment (unless meeting the exception below for piping and components within buildings)
- 500 ppm (or 10 kg/hr mass flow) for infrared, laser-based, mobile, aerial, or satellite-based platforms, or using fixed continuous monitoring sensors within buildings
- 500 parts per million for hand-held equipment used within buildings
- any optical gas imaging or equivalent that meets the requirements of 40 C.F.R. Part 60, subpart OOOO

These minimum sensitivity capabilities reflect an objectively low survey instrument threshold for gas concentration (e.g., for 500 ppm, 1% of the lower explosive limit of methane gas). Specifying a blanket, all-encompassing minimum sensitivity below 500 ppm will deter operators from adopting mobile, aerial, satellite, optical, infrared, or laser-based technologies.

The following alternative leak survey methods must also be available to operators, although prescribing minimum sensitivity requirements is not appropriate at this time:

- use of a soap solution to identify leaks
- non-optical continuous monitoring system (e.g., acoustical or pressure monitoring systems).

While these methods do not avail themselves to prescribing a minimum sensitivity in terms of gas concentration or volumetric/mass flow rate, they are inherently sensitive leak survey

[187] 88 Fed. Reg. at 31,932.
[188] *Id.*, at 31,933.
[189] Proposed Section 192.763(a)(1)(iii)(A)-C).

approaches, and (in the case of continuous monitoring systems) are capable of identifying risks such as leakage due to excavation damage. Disallowing these methods by way of a blanket minimum sensitivity requirement or impracticable performance standard is counterproductive to enhancing pipeline safety and emissions reduction through leak mitigation.

5) Additional performance standards

Incorporation of additional performance standards for evaluating technology effectiveness, as proposed in § 192.763(a)(1)(iii), is redundant and impractical. PHMSA imagines a standard leak, recognized by industry, "of 5 parts per million or more when measured within 5 feet of the pipeline," – something akin to the international prototype meter[190] – against which all leak survey equipment must be evaluated for acceptability. However, defining such a "universal leak" by gas concentration and distance alone fails to consider other critical real-world leak characteristics, such as pipeline burial depth (or for above ground facilities, pipeline height) soil conditions, atmospheric conditions, plume behavior, and probability of detection (POD) of the equipment being used. Even if operators attempted to apply this proposed standard within a controlled environment, it could not be practically or consistently be repeated across industry. PHMSA's proposal in § 192.763(a)(2)(iii) to "have procedures for validating the sensitivity of the equipment before initial use by testing with a known concentration of gas and at the required offset conditions of 5 feet" neither makes reference to the 5 ppm minimum concentration that the equipment is expected to detect, nor controls for the variables discussed previously.

Outside of a controlled environment, application of the standard is even less practicable, particularly as it relates to the stipulation that some leaks must be measured within 5 feet of the pipeline (i.e., if they are of a sufficiently low concentration that they cannot be detected from further away than 5 feet). Wide variability in gas migration and venting patterns, depths of cover regularly in excess of 5 feet, as well as other potential factors make it extremely unlikely that operators can reasonably evaluate the performance of equipment based on prescribing gas concentration and distance from pipe wall alone. Furthermore, the 5 parts per million minimum sensitivity requirement represents a concentration of 0.01% of the lower explosive limit of methane gas. Imposing additional mandates to "[use] locating equipment to verify the tools are sampling the area within 5 feet of the buried pipeline" (as proposed in 192.763(a)(1)(iii)(A)) is at odds with such a conservatively low sensitivity threshold and imposes burdensome prework to handheld leak survey activities.

In order for an instrument performance standard to be applicable, practical, and repeatable under ALDP, it should be made synonymous with minimum sensitivity requirements for leak detection equipment established within the operator's ALDP, and all references to 5 feet offset conditions should be removed.

[190] National Institute of Standards and Technology, *"Meter"*, nist.gov, https://www.nist.gov/si-redefinition/meter

6) Distribution leakage survey frequency

Given the minimum leakage survey frequencies prescribed in §§ 192.706 and 192.723, as well as accelerated or supplemental leakage surveys dictated within an operator's DIMP (based on the risk of materials such as bare steel or cast iron piping, as well as the threat of certain natural force threats, such as frost, earthquakes, or hurricanes), imposing additional mandates related to survey frequency within the ALDP requirements is redundant and inappropriate. Furthermore, the proposed requirements in § 192.763(a)(3) suggest that every leak should be detected through leakage survey, and therefore any leak found outside of a scheduled leak survey is evidence of insufficiently frequent survey practices. This is unreasonable and completely at odds with an approach involving a limited set of prescribed minimum survey frequencies, in combination with risk-based alternatives defined by DIMP.

Consideration of the concerns raised above and additional edits to § 192.763 proposed below should help provide clarity and the flexibility necessary to create and implement a technically feasible and practicable ALDP program that will enhance the leak detection and mitigation activities that operators are currently undertaking through DIMP and other pipeline safety efforts. These considerations will help ensure that the equipment, practices, frequencies, and program evaluations of ALDP will address both public safety and environmental protection effectively.

7) Periodic Evaluation and Improvement

Section 113 of PIPES Act 2020 mandated that the minimum performance standards set by PHMSA "reflect the capabilities of commercially available advanced technologies that, with respect to each pipeline covered by the programs, are appropriate for —

> (i) the type of pipeline;
> (ii) the location of the pipeline;
> (iii) the material of which the pipeline is constructed; and
> (iv) the materials transported by the pipeline.

The revised minimum performance standards proposed by the Associations in § 192.763(a)(1)(ii) (e.g., 5 ppm for hand-held; 500 ppm or 10 kg/hr mass flow for infrared, laser-based, mobile, aerial, satellite-based platforms, and fixed continuous monitoring sensors or hand-held equipment within buildings; or any optical gas imaging or equivalent that meets the requirements of 40 C.F.R. Part 60, subpart OOOO) are broadly applicable and repeatable. Furthermore, they are appropriate for all extant permutations of pipeline types, locations, materials, and media across gas distribution, transmission, and gathering systems regulated by 49 CFR 192. Lastly, the proposed minimum sensitivities (i.e., 0.01-1.0% lower explosive limit equivalent) are more than adequate for identification, locating, and categorization of hazardous or potentially hazardous leaks. Therefore, they meet the requirements for ALDP minimum performance standards specified by Section 113 of PIPES Act 2020.

Per the requirements of Section 113 of PIPES Act 2020, evaluation and improvement of an operator's ALDP is necessary only insofar as the ALDP's performance standards are inappropriate for the operator's pipeline type, location, material, or medium. Therefore, the requirement to perform a formal program evaluation (and, if necessary, improvement) as per § 192.763(a)(4) should be contingent on the introduction of novel pipeline types, locations, materials, or media to an operator's system. Evaluation of advances in leak detection technologies and practices are not required by Section 113 of PIPES Act 2020, and are in any case irrelevant to the performance of an operator's current ALDP. Furthermore, data such as the number of leaks initially detected by the public, number of leaks and incidents, and estimated emissions from leaks detected are either only tenuously related to ALDP performance, or would otherwise be considered as part of an operator's evaluation of leak survey procedure adequacy.

8) Deficiencies in PHMSA's ALDP cost analysis

PHMSA estimates in its PRIA that the costs associated with the new ALDP requirements would be $12 million. This cost is incorrect. PHMSA relies on too narrow of a dataset and its analysis of the costs of its leakage survey proposal are inaccurate. PHMSA based its per-mile cost for leakage surveys on information from a single operator. That operator's mileage and system parameters are not indicative of the entire industry. In fact, a member of one of the Associations estimated that their costs would increase by $24 million a year using PHMSA's assumed rate of $515 per mile. The Agency also acknowledges that it "did not find good estimates of the costs of conducting leak surveys using traditional survey methods only and therefore lacked sufficient information to determine whether the transition to ALD[P] methods results in incremental costs a per mile basis."[191] Although OMB has directed agencies to create a baseline and compare with the costs of the proposed rule, PHMSA has not established an appropriate baseline. PHMSA should reevaluate its assessment of the costs associated with its ALDP and leakage survey requirements.

PHMSA also failed to quantify the safety benefits of expanding the leakage survey requirements. The agency stated that the benefits could be significant, but did not monetarily quantify them.[192] PHMSA must quantify this information to satisfy its statutory requirements. As noted above, the U.S. Circuit Court for the District of Columbia recently held that "without quantified benefits to compare against costs, it is not apparent just how the agency went about weighing the benefits against the costs."[193]

---

[191] PRIA, at 41.
[192] *Id.*, at 91.
[193] *GPA Midstream Ass'n v. United States Dep't of Transportation*, 67 F.4th 1188, 1197 (D.C. Cir. 2023)(citing 49 U.S.C. § 60102(b)(5)).

9) Analysis showing annual estimated costs of $156 million

PHMSA calculated the leakage surveys for a subset of natural gas transmission lines that are leak prone or in an HCA. PHMSA calculated the mileage estimates using a number of assumptions, including that intrastate Class 3 and 4 are odorized and all other lines operate without odorant. PHMSA used the mileage estimates and multiplied by incremental leak survey in Class 1 and 2. PHMSA calculated a $515 per mile leakage survey cost based on 2014 SoCal Gas data. In total, PHMSA estimates the cost of leakage survey requirements at $12 million annually. PHMSA underestimates the cost by first not including all the relevant mileage impacted by the proposed rule, such as aboveground facilities, and also not incorporating the incremental cost of ALD over currently accepted practices (including inflation), which applies to all leak survey.

The following is the Associations' cost analysis for ALDP *(gas transmission)*:

(i) Incremental Leak Survey Frequency Requirement

The Associations recalculated the incremental survey requirement in the NPRM by determining the amount of Class 1 and Class 2 mileage that would be impacted. PHMSA's mileage estimate only included HCA and leak prone pipe in Class 1 and 2 locations but failed to incorporate the number of facilities that would be required to perform additional leak surveys. The Associations estimate that these facility surveys would vary based on class, resulting in a facility every 20 miles in a Class 1 and every 15 miles in a Class 2 location. The amount of impacted mileage totals 30,845 in Class 1 and 4,490 in Class 2. Note that the Agency did not provide mileage breakouts for HCA and leak prone pipe, or the amount of odorized pipeline in these class locations. PHMSA should include these mileage estimates as it reassesses the cost impacts.

Table 9: Incremental Mileage impacts by Class

Class Location	Total 2020 Mileage	HCA Mileage: 7% of All Mileage	2020 Bare Steel (3,504 miles) Annual Report	Above Ground Facilities per Mile	Above Ground Facilities	Total Impacted Mileage
Class 1	234,178	16,392	2,744	20 miles	11,709	30,845
Class 2	30,259	2,118	355	15 miles	2,017	4,490
Class 3	33,775	2,364	396	8 miles	4,222	6,982
Class 4	866	61	10	4 miles	217	287

Using the PHMSA unit cost of $515 for ALD, which as noted above is too low, the Association calculates the addition of 1 leak survey in Class 1 and Class 2 locations at $18 million annually.

Table 10: Increased Frequency of Leak Survey Cost Impacts in Class 1 and 2 Locations (2020)

Class Location	Total Impacted Survey Mileage	Additional Leak Survey Frequency	Cost of ALD	Total Additional Survey
Class 1	30,845	1	$515	$ 15,885,170
Class 2	4,490	1	$515	$ 2,312,304
			TOTAL	$ 18,197,475

(ii) Incremental Cost of the ALD Survey

The Associations also calculated the incremental cost of moving to ALD using the PHMSA unit cost of $515 per mile less $128 which is assumed as the baseline cost in the leak patrol section of the PRIA. This results in the following cost calculations by class, totaling over $138 million annually using 2020 mileage estimates.

Table 11: Increased Cost of Leak Surveys Using ALD Methods (2020)

Survey Frequency less Incremental Survey in Class 1 and 2	Incremental Cost of ALD $515 - $128 = $387	Total mileage by Class	TOTAL Incremental Cost
Class 1: 1 survey	$387	245,887	$95,158,230
Class 2: 1 survey	$387	32,276	$12,490,915
Class 3: 2 surveys	$387	37,997	$29,409,581
Class 4: 4 surveys	$387	1,083	$1,675,710
		TOTAL	$138,734,437

Adding the cost of the incremental survey plus the incremental cost of ALD, the total equates to over $128 million annually using a 3 percent discount rate.

Table 12: Total Leak Survey Cost

Year	Incremental Survey Frequency	Incremental Cost of ALD Survey	TOTAL Incremental ($M)
2024	$18	$139	$157
2025	$18	$139	$157
2026	$18	$139	$157
2027	$18	$139	$157
2028	$18	$139	$157
2029	$18	$139	$157
2030	$18	$139	$157

2031	$18	$139	$157
2032	$18	$139	$157
2033	$18	$139	$157
2034	$18	$139	$157
2035	$18	$139	$157
2036	$18	$139	$157
2037	$18	$139	$157
2038	$18	$139	$157
3%			$1,927.42
7%			$1,527.65
3% Annualized			$128.49
7% Annualized			$101.84

10) <u>Necessity of a 36-months compliance date for the development of an operator's Advanced Leak Detection Program under 192.763</u>

The agency proposes that the ALDP requirements would become effective six months after the publication of a Final Rule. This is not feasible, reasonable, or practicable. As discussed later in these comments, the Associations are highly concerned with a six month effective date for all new and revised regulatory requirements. As discussed in detail on pages 146-148, PHMSA should provide operators 36 months to develop the ALDP and the enhanced leak management protocols under 192.760. Only after both are developed can any work per 192.705, 192.706 and 192.723 be conducted as leak surveys, leak investigations, leak grading and leak repair would be governed under the ALDP. A uniform effective date of 6 months is inadequate for both operators and regulators who will be providing enforcement.

11) <u>ALDP records retention</u>

PHMSA proposes in § 192.763(b)(2) that "records validating that the ALDP meets the performance standard must be maintained for at least 5 years after the date that ALDP is no longer used by the operator."[194] Given that the ALDP requirements proposed in § 192.763 describe an ongoing program (singular) that operators would be required to adhere to, periodically evaluate, and amend, the implication seems to be that records described in § 192.763(b)(2) must be retained indefinitely. The Associations maintain that the requirement to have a written program (§ 192.763(a)), to document improvements (§ 192.763(a)(4)), and to retain records related to equipment sensitivity (§

[194] 88 Fed. Reg. at 31,978.

192.763(a)(2)(iii)[195]) and calibration (§ 192.763(a)(2)(iv)) are sufficient to demonstrate a robust and rigorous ALDP.

Based on the discussion above, the Associations suggest the following changes be made to the newly proposed regulation on ALDP:

§ 192.763 Advanced Leak Detection Program

(a) Advanced Leak Detection Program (ALDP) elements. Each operator must have and follow a written ALDP that includes the following elements:

(1) Leak detection equipment.

(i) The ALDP must ~~include a list of~~ identify operator-approved leak detection equipment used to perform ~~in operator~~ leakage surveys and other leak detection activities~~, pinpointing leak locations, and investigating leaks.~~

(ii) Unless using non-optical continuous monitoring system (e.g., acoustical or pressure monitoring systems) or soap solution, ~~L~~leak detection equipment used for leakage surveys~~, pinpointing leak locations, investigating, and inspecting leaks~~ must have a minimum sensitivity capability of one of the following:

(A) 5 parts per million for each gas being surveyed using handheld leak detection equipment, unless described in § 192.763(a)(1)(ii)(C);

(B) 500 parts per million (or 10 kg/hr mass flow equivalent) for each gas being surveyed using infrared or laser-based leak detection equipment; mobile, aerial, or satellite-based platforms; or using fixed continuous monitoring sensors within buildings;

(C) 500 parts per million for each gas being surveyed within buildings using handheld leak detection equipment; or

(D) sensitivity otherwise meeting the requirements of 40 C.F.R. Part 60, subpart OOOO for optical gas imaging or equivalent

Before using this equipment in a leakage survey, t~~T~~he operator must validate the sensitivity at which the survey is to be conducted ~~of this equipment before using the device in a leakage survey~~ by testing in accordance with manufacturer's instructions~~with a known concentration of gas.~~

(iii) Records validating that the ALDP equipment meets the minimum sensitivity requirements must be maintained for at least 5 years after the date that equipment is no longer used by the operator.

[195] Revision proposed by the Associations to require as part of § 192.763(a)(1) "Records validating that the ALDP equipment meets the minimum sensitivity requirements must be maintained for at least 5 years after the date that equipment is no longer used by the operator."

~~(iii) Leak detection equipment must be selected based on a documented analysis considering, at a minimum, the state of commercially available leak detection technologies and practices, the size and configuration of the pipeline system, and system operating parameters and environment. At a minimum, operators must analyze the effectiveness of the following technologies for their systems:~~

~~(A) The use of handheld leak detection equipment capable of detecting and pinpointing all leaks of 5 parts per million or more; when measured within 5 feet of the pipeline or within a wall-to-wall paved area, in conjunction with locating equipment to verify the tools are sampling the area within 5 feet of the buried pipeline. The procedure must include sampling the atmosphere near cracks, vaults, or any other surface feature where gas could migrate;~~

~~(B) Periodic surveys performed with leak detection equipment mounted on mobile, aerial, or satellite-based platforms that, in conjunction with confirmation by hand-held equipment, is capable of detecting and pinpointing all leaks of 5 parts per million or more; when measured within 5 feet of the pipeline, or within a wall-to-wall paved area;~~

~~(C) Periodic surveys performed with optical, infrared, or laser-based leak detection equipment that can sample or inspect the area within 5 feet of the pipeline, or within a wall-to-wall paved area, capable of detecting and pinpointing all leaks of 5 parts per million or more;~~

~~(D) Continuous monitoring for leaks via stationary sensors, pressure monitoring, or other means of continuous monitoring that provide alarms or alerts and that, in conjunction with confirmation by hand-held equipment, is capable of detecting and pinpointing all leaks of 5 parts per million or more when measured within 5 feet of the pipeline, or within a wall to-wall paved area; and~~

(E) ~~Systematic use of other commercially available technology capable of detecting and pinpointing all leaks producing a reading of 5 parts per million or more within 5 feet of the pipeline, or within a wall-to-wall paved area.~~

(2) Leak detection practices. At a minimum, an operator must have and follow written procedures within their ALDP for:

(i) Performing leakage surveys~~. Operators must have procedures for performing leakage surveys~~ required for §§ 192.706 and 192.723 using equipment identified in ~~each selected leak detection technology as described in~~ paragraph § 192.763(a)(1). The procedures must define any environmental ~~and~~or operational condition~~s~~ limits for the use of the equipment ~~which each leak detection technology is and is not permissible~~. The operator's procedures should be in alignment with ~~must follow~~ the leak detection equipment manufacturer's instructions ~~for survey methods and allowable environmental and operational parameters~~.

(ii) ~~Pinpointing and investigating leaks. The location of the source of each l~~Leak survey indications on ~~an~~ onshore pipelines or any portion of an offshore pipelines above the waterline must be ~~pinpointed and~~ investigated with ~~handheld~~ leak detection equipment or soap testing. Leak indications on onshore waterbody crossings and offshore pipelines below the waterline may be pinpointed with human senses.

(iii) Calibrating equipment in accordance with the manufacturer's written recommendations. ~~Validating performance. Operators must have procedures validating that leak detection equipment meets the requirement of paragraph (a)(1)(ii) of this section. The operator must have procedures for validating the sensitivity of the equipment before initial use by testing with a known concentration of gas and at the required offset conditions of 5 feet. Records validating equipment performance must be maintained for five years after the date the device is no longer used by the operator.~~

~~(iv) Maintaining and calibrating leak detection equipment. At a minimum, procedures must follow the equipment manufacturer's instructions for calibration and maintenance. Leak detection equipment must be recalibrated or replaced following any indication of malfunction.~~ Records demonstrating ~~validating~~ equipment calibration ~~and failures indicating recalibration is necessary~~ must be maintained for 5 years ~~after the date the individual device is retired by the operator~~.

(3) Leakage survey frequency shall not exceed the defined intervals required by~~. Leakage survey frequency must be sufficient to detect all leaks that have a sufficient release rate to produce a reading of 5 parts per million or more of gas when measured from a distance of 5 feet or less from the pipeline, or within a wall to- wall paved area, but may be no less frequent than required in~~ §§ 192.706 and 192.723. Leak survey intervals may need to be shorter than those requirements based on known factors such as ~~L~~less sensitive equipment, challenging survey conditions, or facilities known to leak based on their material, design, or past operating and maintenance history ~~may require more frequent surveys to detect leaks consistent with paragraph (b) of this section~~.

(4) Program ~~Periodic~~ evaluation and improvement. ~~The ALDP must include procedures and records showing the operator is meeting all of the program requirements.~~

(i) The operator must evaluate the ALDP at least once each calendar year but with a maximum interval not to exceed 15 months.

~~(ii) The operator must make changes to any program elements necessary to locate and eliminate leaks and minimize releases of gas.~~

(ii) When considering changes to program elements, operators must ~~analyze, at a minimum~~ evaluate, the impact (if any) of novel pipeline types, locations, materials, or media on the operator's system that may influence the performance of the leak detection equipment used, and the adequacy of the leakage survey procedures~~, advances in leak detection technologies and practices, the number of leaks that are initially detected by the public, the number of leaks and incidents, and estimated emissions from leaks detected pursuant to this section~~.

(iii) The operator must document any improvements made~~needed~~ to the program.

(b) ~~Advanced leak detection performance standard. Each operator's ALDP described in paragraph (a) of this section must be capable of detecting leaks that have a sufficient release rate to produce a reading of 5 parts per million or more of gas when measured from a distance of 5 feet or less from the pipeline, or within a wall-to-wall paved area.~~

~~(1) The performance of the ALDP equipment must be validated and documented with engineering tests and analyses.~~

~~(2) Records validating that the ALDP meets the performance standard must be maintained for at least 5 years after the date that ALDP is no longer used by the operator.~~

Alternative advanced leak detection performance standard. ~~For gas pipelines other than natural gas pipelines, and for natural gas transmission, offshore gathering, and Types A, B, and C gathering pipelines located in Class 1 or Class 2 locations,~~ A~~a~~n operator may use an alternative ALDP performance standard (and supporting leak detection equipment) with prior notification to, and with no objection from, PHMSA in accordance with § 192.18. PHMSA will only approve a notification if operator, in the notification, demonstrates that the alternative performance standard is consistent with pipeline safety and equivalent to the standard in paragraph ~~(b)~~ (a) of this section for reducing greenhouse gas emissions and other environmental hazards. The notification must include:

(1) Mileage by system type;

(2) Known material properties, location, HCAs, operating parameters, environmental conditions, leak history, and design specifications,

including coating, cathodic protection status, and pipe welding or joining method;

(3) The proposed performance standard;

(4) Any safety conditions, such as increased survey frequency;

(5) The leak detection equipment, procedures, and leakage survey frequencies the Operator proposes to employ;

(6) Data on the sensitivity and the leak detection performance of the proposed Alternative ALDP standard; and

(7) The gas transported by the pipeline.

D. Leakage Survey and Patrol Frequencies and Methodologies

1) Distribution—§ 192.723

a) Distribution Leak Survey Frequency

Section 192.723 requires gas distribution operators to perform leak surveys every 5-years not to exceed 63 months. A reasonable test for whether the current leak survey frequency is appropriate, relative to annual (not to exceed 15 months) leakage survey inside business districts, is whether *leaks found-per mile-per year* (i.e., normalized by survey interval) is substantially the same across leakage survey types. If this number is significantly higher for pipelines outside of business districts, it would suggest that the difference in leak proneness between piping inside and outside of business districts is not reflective of a 5:1 ratio, and that 5 years is therefore too infrequent for leakage surveys outside of business districts.

However, available data does not support this scenario. In a small convenience sample of 9 gas distribution pipeline operators, the Associations found no instance in which *leaks found-per mile-per year* was higher outside of business districts than it was inside of business districts. If anything, the available data suggests that a 5-year survey is an aggressive frequency relative to the typical rate of leaks found during annual leakage survey inside business districts. Therefore, the Associations believe the proposed amendments in this NPRM to increase distribution leakage survey frequency outside of business districts from 5 years (not to exceed 63 months) to 3 years (not to exceed 39 months) is not justified by leak reduction projections, nor an improvement in pipeline safety.

Risk reduction through leak survey frequency adjustment is better achieved through a less-prescriptive, risk-based approach (e.g., DIMP), since operators know their system, geography, conditions, and operational idiosyncrasies. Frequency of leakage surveys can be (and are) accelerated by operators based on risk and performance of their systems. The successful risk-based utilization of DIMP to appropriately increase leak surveys includes targeted leak surveys on pre-1940 steel and pre-1973 Aldyl-A vintages, which have shown to have higher leak rates. Furthermore, cathodically unprotected or anode CP systems deficient reads should not require further acceleration of leakage survey since the requirements in Subpart I (Corrosion Control) already provide additional risk mitigation for this pipe.

b) Distribution Leak Survey Following Environmental Changes

The proposed provision for investigating known leaks after environmental changes (§192.723(e)) is problematic for three reasons. First, this provision does not belong in a section dedicated to leak surveys. The investigation of known leaks is inconsistent with “leakage survey” activities prescribed in § 192.723, the purpose of which is to find indications of gas leaks, as opposed to monitoring or checking known leaks. Second, § 192.723(e) is redundant with the proposed provision in § 192.760(c)(5) for mitigating risks of environmental changes to known Grade 2 leaks. Lastly, environmental changes such as “freezing ground” or “heavy rain” are so broad, intermittent, and (in many operational areas) commonplace that the rule essentially suggests continuous investigation of known leaks for days, weeks, or longer, depending on weather conditions.

Any provision for weather-related investigations of known leaks should be limited to the leak grading and repair rule (§ 192.760), and operators must be given latitude to define environmental changes that would necessitate these investigations, based on their unique geography, climate, and other environmental conditions.

c) Distribution Leak Survey Following Extreme Weather

PHMSA proposes operators perform a leakage survey following “extreme weather and land movement” within 72 hours after the cessation of the event or once the facility is returned to service. The Associations recommend PHMSA provide more clarity on the types of weather events or land movement that would require these additional leak surveys. The Associations suggest that PHMSA use the same detailed language currently in § 192.613(c) for Continuing surveillance after extreme weather or natural disasters. This list of example weather events will ensure consistent interpretation of when an operator is to perform an additional leak survey above and beyond the prescriptive cycles detailed in § 192.723(b)-(d).

The Associations also recommend that PHMSA add language describing which portions of the pipeline facility must be leak surveyed. Absent this clarity, operators in some portions of the country will be required to leak survey their entire pipeline system multiple times each year. For example, in 2020 the Florida panhandle and southern Alabama experienced 3 hurricanes and one tropical storm. As proposed § 192.723(f) would have required operators in that area to perform 4 leak surveys *on their entire system* in 2020 *in addition to* the prescriptive leak surveys they were performing per § 192.723(b)-(d).

PHMSA must clarify that only portions of a pipeline facility directly impacted by extreme weather, the results of the extreme weather (such as downed trees), or land movement should be leak surveyed after the event.

d) Retroactive Compliance

Coated steel and plastic mains are currently leak surveyed on a 5-year cycle. PHMSA is proposing a 3-year cycle for these mains. The proposed 6-month effective date of the rule will result in many operators being automatically out-of-compliance with the new frequency.

The Associations recommend the following changes to PHMSA's proposed regulatory text for §192.723:

§ 192.723 Distribution systems: Leakage surveys.

(a) General. Each operator of a gas distribution pipeline must conduct periodic leakage surveys with leak detection equipment in accordance with this section. All leakage surveys performed pursuant to this section must use leak detection equipment that meets the requirements of § 192.763.

(b) Business districts. Leakage surveys must be conducted at least once each calendar year, at intervals not exceeding 15 months, consisting of atmospheric tests at each gas, electric, telephone, sewer, water, or other system manhole; crack in the pavement and sidewalks; and any other location that provides an opportunity for finding gas leaks.

(c) Non-business districts. Leakage surveys must be conducted at least once every 5 ~~3~~ calendar years, at intervals not exceeding 63 ~~39~~ months, unless a shorter inspection interval is required either by paragraph (d) of this section, the operator's operations and maintenance procedures, or the operator's integrity management plans under part 192, subpart P.

(d) Frequency of regular leakage surveys. Leakage surveys must be conducted at least once every calendar year, at intervals not exceeding 15 months, for~~:~~

~~(1) Cathodically unprotected distribution pipelines subject to § 192.465(e);~~

~~(2) P~~pipelines ~~known to leak based on their material (including cast iron, unprotected steel, wrought iron, and~~ constructed of ~~historic~~ plastics with known issues~~), design,~~ or pipelines known to leak based on past operating and maintenance history~~; and~~

~~(3) Gas distribution pipeline systems protected by a distributed anode system, in the area of deficient readings identified during a cathodic~~

~~protection survey pursuant to § 195.463 and Appendix D, until the cathodic protection deficiency is remediated.~~

~~(e) Investigating known leaks after environmental changes. An operator must periodically investigate a known Class 2 leak, including conducting a leakage survey for possible gas migration, as soon as practicable when environmental changes such as freezing ground, heavy rain, flooding, or other changes to the environment, as identified in the operator's procedures (DIMP, O&M, etc.), occur that could affect the venting of gas or could cause migration of gas to the outside wall of a building.~~

(e) Extreme Weather Surveys. Leakage surveys must be performed after extreme weather events and land movement with the likelihood to cause damage to the affected pipeline segment. The survey must be initiated within 72 hours after the cessation of the event, defined as either the point in time when the affected area can be safely accessed by the personnel and equipment required to perform the leakage survey or when the facility has been returned to service.

2) *Transmission Pipelines—§§ 192.705 and 192.706*

a) Existing Practices

1) PHMSA's assumption that all gas transmission operators currently patrol their rights-of-way (ROWs) on a monthly basis is incorrect.

PHMSA proposes that operators will need to patrol all gas transmission ROWs at least twelve times each calendar year at intervals not exceeding 45 days.[196] The assumption that all gas transmission operators are voluntarily patrolling ROWs monthly instead of the regulatory required one to four times per year is incorrect and unsupportable.[197] Not all gas transmission operators patrol their entire system monthly. In fact, not all transmission operators rely on aerial patrols to inspect their ROWs. In some cases, the pipelines are too close in proximity, difficult to fly the full length of the right-of-way, or include a branching network or storage or gathering assets that do not lend themselves to aerial patrolling. Furthermore, many pipelines traverse regions susceptible to several months of snow cover. For those situations, many operators opt to conduct ground patrols or patrol certain ROWs via motor vehicle or all-terrain vehicle. The current pipeline safety

[196] Proposed Section 192.705(b).

[197] The pipeline safety regulations currently require patrols every 4 ½ months to every 15 months depending on the location of the pipeline.

regulations allow for this flexibility.[198] Some operators use a risk-based approach and focus more frequent pipeline patrols on the riskier segments of their pipeline systems (e.g., population near the ROW, areas known for more frequent ground movement, twice per month patrols during greater contractor work near pipeline at specific times of the year, or other specific threats to the pipeline). PHMSA supports its assumption by referencing a single operator's voluntary commitment.[199] The agency also references the practices of unnamed gas transmission operators and then concludes that "this practice is common across transmission operators."[200] INGAA's members are all gas transmission operators and can report that while some operators may choose to patrol specific ROWs more frequently than required, it is not accurate to conclude that <u>all</u> gas transmission operators patrol on a monthly basis.

b) Assessment of Costs and Benefits of Proposed Change

1) PHMSA's established baseline for transmission patrols is not supported by the Office of Management and Budget's Circular A-4 or related case law.

The Office of Management and Budget (OMB) directs executive agencies to identify a baseline when evaluating the benefits and costs of a proposed regulation and its alternatives.[201] OMB defines the baseline as "what the world will be like if the proposed rule is not adopted"[202] and then the agency compares the cost of that approach with its proposal.[203] Incremental costs are then defined as the "difference between a proposed action's costs and the benefits and the baseline."[204] PHMSA initially states in its PRIA that the baseline for patrol costs is one to four times per year[205] but then assumes "that operators of onshore and offshore gas transmission pipelines and Type A regulated gas gathering lines perform patrols at least once per month in the baseline."[206] The Agency proceeds to calculate the costs of moving patrol requirements from one to four times per year to every month as a zero incremental cost.[207] Numerous federal courts have accepted the baseline

---

198 Section 192.705(c)("Methods of patrolling include walking, driving, flying, or other appropriate means of traversing the right-of-way.")
199 PRIA, at 37.
200 PHMSA states that "[g]iven baseline practices, PHMSA estimates that the proposed enhanced patrolling requirements will result in no incremental costs for onshore and offshore transmission and Type A regulated gas gathering pipeline patrol requirements under the proposed rule." PRIA, at 37-38.
201 OMB Circular A-4. .
202 *Id.* at 15,
203 *Cape Hatteras Access Pres. All. v. U.S. Dep't of Interior*, 344 F. Supp. 2d 108, 130 (D.D.C. 2004).
204 OMB Circular A-4 at 16.
205 PRIA, at 37.
206 *Id.*
207 *Id.*, at 37 ("Given baseline practices, PHMSA estimates that the proposed enhanced patrolling requirements will result in no incremental costs for onshore and offshore transmission and Type A

approach and also confirmed that a baseline is what the world would look like without an agency's proposal.[208] Incorporating the voluntary practices of a single operator as the baseline for the entire industry is not supportable and contrary to the direction of OMB's Circular and conclusions in federal case law. The impact of moving from once per calendar year to a monthly patrol requirement is a twelve-fold increase. PHMSA cannot expect those operators that currently walk each mile in their system in compliance with Section 192.705 to walk those same rights-of-way on a monthly basis and conclude that there is a zero incremental cost associated with this effort. Similarly, a reduction of environmental benefits should also be considered, given the amount of secondary emissions associated with increasing truck rolls by a magnitude of twelve.

2) PHMSA's PRIA analyzing costs of the more frequent patrols is incorrect.

The agency acknowledges in the PRIA that some operators may not currently conduct patrols monthly and calculates the impact for *intrastate* pipelines as between $35 million to $140 million per year.[209] PHMSA limits this cost assessment to intrastate operators with arguably shorter pipelines and uses a cost of $128 per mile[210] to calculate the total cost. In one section of the PRIA, PHMSA states that the appropriate cost is $128 per mile[211] but then in other sections of the PRIA, the agency notes that the unit cost is $218 per mile.[212]

PHMSA should recalculate the patrol costs following the direction of OMB Circular A-4 and relevant case law. PHMSA should use the current requirements in Section 192.705(b) as the baseline and compare with the proposed rule to produce the incremental cost impact. The Associations have assessed those costs and provide the following data:

The Associations developed costs based on first developing the mileage impacts by year and class location using the increase in mileage extrapolated through 2038 that was provided by PHMSA in the PRIA. The following table contains the transmission mileage by class starting in 2024 and increasing through 2038.

---

regulated gas gathering pipeline patrol requirements under the proposed rule.") *See also,* PRIA, at 141 ("Operators of gas transmission and Type A gas gathering pipelines are assumed to perform patrols at least once per month in the baseline under current practice…and therefore there are zero incremental costs for patrol requirements under the proposed rule.")

[208] *See Ariz. Cattle Growers' Ass'n v. Salazar*, 606 F.3d 1160, 1173 (9th Cir. 2010); *Fisher v. Salazar*, 656 F. Supp. 2d 1357, 1371 (N.D. Fla. 2009); *Cape Hatteras Access Pres. All. v. U.S. Dep't of Interior*, 344 F. Supp. 2d 108, 130 (D.D.C. 2004).

[209] PRIA, at 38, fn. 31 (11 patrols x 99,129 miles x $32 x $128 per mile).

[210] *Id.*, at 37.

[211] *See* id. at 38, fn. 31; *See also,* id. at 140.

[212] *Id.*, at 141.

Table 13: Transmission Mileage by Class

Year	Class 1 mileage	Class 2 Mileage	Class 3 Mileage	Class 4 Mileage
2024	242,147	31,282	34,669	875
2025	244,173	31,544	34,896	877
2026	246,199	31,806	35,123	879
2027	248,416	32,084	35,365	881
2028	250,632	32,362	35,607	883
2029	252,849	32,640	35,850	886
2030	255,065	32,918	36,092	888
2031	257,282	33,196	36,334	890
2032	259,607	33,484	36,587	892
2033	261,932	33,772	36,840	894
2034	264,256	34,059	37,094	897
2035	266,581	34,347	37,347	899
2036	268,906	34,635	37,600	901
2037	271,231	34,923	37,853	903
2038	273,556	35,211	38,106	905

The Associations calculated the low and high cost based on unit cost data included in the PRIA and the incremental patrol frequency compared to the current regulatory patrol frequency requirements: 11 additional patrols in Class 1 and Class 2, 10 additional patrols in Class 3, and eight patrols in Class 4 locations respectively.

Table 14: Recalculated Summary of Incremental Patrol Costs (millions 2020, annualized with 3 and 7 percent discount rate)

Year	Low Cost: $32 ($M)	High Cost: $128 ($M)
2024	$108	$430
2025	$108	$434
2026	$109	$437
2027	$110	$441
2028	$111	$445
2029	$112	$449
2030	$113	$453
2031	$114	$456
2032	$115	$460
2033	$116	$464
2034	$117	$468
2035	$118	$472
2036	$119	$476

2037	$120	$480
2038	$121	$484
3% Total	**$1,398**	**$5,591**
7% Total	**$1,101**	**$4,405**
3% Annualized	**$93**	**$373**
7% Annualized	**$73**	**$294**

Thus, assuming for argument that PHMSA's unit costs values are accurate, the estimated cost impacts of increasing the patrol frequency to 12 times per year is between $93 million and $373 million per year based on annualized costs using a three percent discount rate.

Additionally, PHMSA must also assess the costs for those operators who primarily conduct foot patrols. If PHMSA pursues a monthly patrol requirement, it may become too arduous to conduct foot patrols each month. Those companies would need to evaluate their ROWs for vegetation if switching to aerial patrols. The costs of that assessment and the related costs to clear ROWs (ground clearing and canopy trimming) were not included in PHMSA's PRIA. Without an adequate cost assessment, PHMSA cannot satisfy its statutory requirements for its revisions to Section 192.705(b).

(3) PHMSA's PRIA is also deficient since no benefits for the additional patrols were identified.

The agency does not identify any benefits associated with increasing the frequency of right-of-way patrols for all transmission pipelines to 12 times per year. The Associations agree that right-of-way patrols allow an operator to view encroachments or class changes, and some operators may choose to patrol their rights-of-way more frequently. Yet, PHMSA clearly states in the NPRM that visual inspection of rights-of-ways is no longer acceptable to the agency for leakage survey purposes. Therefore, it is questionable why adding between eleven and eight additional patrols per year is necessary if they are not used for leak detection.

In short, the PRIA does not identify any benefits (safety, environmental, or otherwise) that can be fairly attributed to the proposed dramatic increase in the frequency of pipeline ROW patrolling. Without an adequate risk assessment, PHMSA cannot satisfy the reasoned decision-making requirement in the Pipeline Safety Act.

c) Recommended Frequency

1) PHMSA should establish the minimum required patrol frequency at 6 times per calendar year.

PHMSA should establish the minimum required patrol frequency at 6 times per calendar year, not to exceed intervals of 75 days. The current requirement is between one to four times per year depending on the location. PHMSA has not supported the need to increase the frequency twelvefold. The agency also proposes that patrols must not exceed intervals of 45 days. In the winter months, certain locations in the United States become very difficult to patrol, particularly on foot. After significant snowfall, or during persistent inclement weather that does not accommodate safe aerial patrols, a 45-day window may be difficult to achieve. Operators need the flexibility to balance PHMSA's goal of increasing patrols with the safety risks of requiring foot patrols in areas with potentially dangerous weather conditions. A 75-day interval is more feasible.

2) PHMSA should also allow operators to choose a risk-based approach as an alternative.

The Associations recommend that PHMSA allow operators to choose an alternative patrol frequency. This risk-based approach would build upon the agency's current methodology in Section 192.705. From 1975 to present day, PHMSA has established patrol frequency based on the class location of the pipeline. Operators with pipelines in more populated areas patrol more frequently than those in rural areas. PHMSA has not explained in the NPRM why this approach is suddenly deficient and instead why it is switching to a universal 12 times per year approach regardless of the size, operating pressure, condition, or location of the pipeline. The agency continues to allow leakage survey frequencies to be defined by risk and should apply the same approach to patrols. Recognizing that the pipeline safety regulations are minimum standards and operators are free to patrol more frequently than required by the regulations, PHMSA should propose the following:

Class location of line	Current Requirements (Excluding Highway and Railroad Crossings)	Recommended Frequency
1	15 months, but at least once each calendar year	4 ½ months, but at least four times each calendar year
2	15 months, but at least once each calendar year	4 ½ months, but at least four times each calendar year
3	7 ½ months, but at least twice each calendar year	2 ½ months, but at least six times each calendar year

4	4 ½ months, but at least four times each calendar year	2 ½ months, but at least six times each calendar year

All gas transmission operators are also subject to the current Section 192.613(c) requirements and may conduct additional patrols after a 192.613(c) inspection. These regulations require operators to inspect potentially affected pipeline facilities after an extreme weather event or natural disaster.[213] An operator must commence the inspection within 72 hours after the point in time when the operator reasonably determines that the affected area can be safely accessed by personnel and equipment, and the personnel and equipment are available.[214]

d) Survey Frequency on the Alaska North Slope (ANS)

Proposed 49 CFR §192.763(1) does not list specific leak detection equipment for operators to utilize, but rather requires a minimum sensitivity that the technology must achieve. This section of the proposed rule fails to account for technological constraints in cold weather environments. This section inappropriately assumes that all technologies meeting the required minimum sensitivity will function properly in all ambient temperature conditions. Many leak detection technologies have a minimum ambient temperature operability threshold prescribed by the manufacturer, below which the technology will not function as designed. Special cold weather considerations must be accounted for when prescribing technologies.

On the Alaska North Slope (ANS) average temperatures can remain below 0°F for more than five consecutive months out of the year[215]. Many leak detection technologies have minimum temperature operability requirements of -4°F, which include but are not limited to optical gas imaging cameras, flame ionization detectors, and photoionization detectors[216].

The Environmental Protection Agency (EPA) recognized this constraint in their New Source Performance Standards (NSPS) Subpart OOOOa (OOOOa) rule (when they began requiring semiannual leak detection and repair) and incorporated annual leak detection surveys for locations on the ANS in a direct final rule amendment in 2018[217]. The EPA stated in the 2018 direct final rule preamble, "[EPA] now conclude that monitoring may not be technically feasible on

[213] 49 C.F.R. § 192.613(c).
[214] *Id.*
[215] EPA-HQ-OAR-2010-0505-6947: Letter from Laura Perry, ConocoPhillips Alaska to U.S. EPA RE: Docket ID No. EPA-HQ-OAR-2010-0505; Comments on Oil and Natural Gas Sector: Emission Standards for New and Modified Sources (Federal Register, Vol. 80, No. 181, September 18, 2015)
216 EPA-HQ-OAR-2010-0505-12434: Letter from Laura Perry, ConocoPhillips Alaska to U.S. EPA RE: Docket ID No. EPA-HQ-OAR-2010-0505; Comments on Oil and Natural Gas Sector: Emission Standards for New and Modified Sources: Stay of Certain Requirements (Federal Register, Vol. 82, No. 215, November 8, 2017) and Docket ID No. EPA-HQ-OAR-2017-0346; Comments on Oil and Natural Gas Sector: Emission Standards for New and Modified Sources: Three Month Stay of Certain Requirements (Federal Register, Vol. 82, No. 215, November 8, 2017)
[217] Federal Register Vol. 83, No. 48

the Alaskan North Slope for close to 6 consecutive months (November through April) due to the extreme cold temperatures that could render the monitoring instruments inoperable. Therefore, the EPA now concludes that annual monitoring more accurately reflects the [Best System of Emission Reduction] for monitoring fugitive emissions at well sites on the Alaskan North Slope because of the infeasibility of semiannual monitoring." The OOOOa annual leak detection frequency for the ANS is specified at 40 CFR §60.5397a(g)(1), "A monitoring survey of each collection of fugitive emissions components at a well site located on the Alaskan North Slope must be conducted at least annually. Consecutive annual monitoring surveys must be conducted at least 9 months apart and no more than 13 months apart." This annual requirement for the ANS is retained in the currently proposed NSPS OOOOb and NSPS OOOOc rules at 40 CFR §60.5397b(g)(1)(v)[218] and 40 CFR §60.5397c(g)(1)(v)[219] respectively.

Given the infeasibility of monitoring for leaks in sustained arctic conditions, transmission pipelines on the ANS should only require annual leakage surveys.

e) Recommended Changes to Regulatory Text

The Associations provide the following changes to the regulatory text in Part 192 for PHMSA's consideration:

§ 192.705 Transmission lines: Patrolling.

* * * * *

(b) Operators must conduct patrols:

(1) At least ~~12~~ 6 times each calendar year at intervals not exceeding ~~45~~ 75 days; or

(2) A risk-based approach considering the size of the line, the operating pressures, the class location, terrain, weather, and other relevant factors, with the following maximum intervals:

Class location of line	**Maximum Interval Between Patrols**
1	4 ½ months, but at least four times each calendar year
2	4 ½ months, but at least four times each calendar year
3	2 ½ months, but at least six times each calendar year
4	2 ½ months, but at least six times each calendar year

* * * * *

218 https://www.epa.gov/system/files/documents/2022-11/8510_OilandGasClimate_OOOObRegText_Supplemental_20221005.pdf

219 https://www.epa.gov/system/files/documents/2022-11/8510_OilandGasClimate_OOOOc%20RegText_Supplemental_20221005.pdf

§ 192.706 Transmission lines: Leakage surveys.

(a) *General.* Each operator must perform periodic leakage surveys in accordance with this section. Each leakage survey must be conducted according to the advanced leak detection program requirements in § 192.763, except that human or animal senses may be used in lieu of leak detection equipment only in the following circumstances:

(1) An offshore gas transmission pipeline below the waterline or offshore gathering pipeline below the waterline; or

(2) An onshore transmission line outside of an HCA or a gathering pipeline, each either in a Class 1 or Class 2 location, with advance notification to PHMSA in accordance with § 192.18. The notification must include tests or analyses demonstrating that the survey method would meet the ALDP performance standard in § 192.763(b) or (c) (as applicable).

(b) *Frequency of surveys.* Except as provided in paragraphs (c) and (d) of this section, leakage surveys must be performed at the following intervals:

(1) Pipelines outside of HCAs or located on the Alaskan North Slope (ANS) must be surveyed at least once per calendar year, but with an interval between surveys not to exceed 15 months; and

(2) Pipelines in HCAs must be surveyed as follows, unless they are located on the Alaskan North Slope (ANS):

(i) In Class 1, Class 2, and Class 3 locations, at least twice each calendar year, with intervals not exceeding 7 ½ months;

(ii) In Class 4 locations, at least four times each calendar year, with intervals not exceeding 4 ½ months.

(c) *Non-odorized pipelines.* Leakage surveys ~~of a transmission line~~ for pipelines ~~must be conducted at intervals not exceeding 15 months, but at least once a calendar year~~ transporting gas in conformity with § 192.625 without an odor or odorant, must perform leakage surveys using leak detection equipment at the following intervals:

(1) In Class 3 locations, at least twice each calendar year, at intervals not exceeding 7 ½ months.

(2) In Class 4 locations, at least four times each calendar year, at intervals not exceeding 4 ½ months.

(d) *Valves, flanges and certain other facilities.* Leakage surveys of all valves, flanges, pipeline tie-ins with valves and flanges, ILI launcher and ILI receiver facilities, and pipelines known to leak based on material (including cast iron, unprotected steel, wrought iron, and historic plastics with known issues), design, or past operating and maintenance history, must be performed at the following intervals:

(1) In Class 1, Class 2, and Class 3 locations, at least twice each calendar year, at intervals not exceeding 7 ½ months.
(2) In Class 4 locations, at least four times each calendar year, at intervals not exceeding 4 ½ months.

3) *Liquified Natural Gas Facilities - § 193.2624*

a) Background

PHMSA regulates the safety of liquefied natural gas (LNG) facilities pursuant to the authority provided in the Pipeline Safety Act, a statute originally enacted by the Natural Gas Pipeline Safety Act of 1968, Pub. L. No. 90-481, 82 Stat. 720, and amended in the Pipeline Safety Act of 1979, Pub. L. No. 96-129, § 152, 93 Stat. 989, 999, to include specific provisions for the siting, design, construction, testing, operation, and maintenance of LNG facilities. 49 U.S.C. § 60103. As currently codified in 49 C.F.R. Part 193, PHMSA's LNG regulations include separate subparts for siting, design, construction, equipment, operations, maintenance, personnel qualification and training, fire protection, and security. PHMSA incorporates several technical standards by reference into Part 193, including the 2001 edition of the National Fire Protection Association, Standard for the Production, Storage, and Handling of Liquefied Natural Gas (2001 NFPA 59A), which is referenced in various provisions, and the 2006 edition of National Fire Protection Association, Standard for the Production, Storage, and Handling of Liquefied Natural Gas, which is referenced in certain provisions for LNG storage tanks, 49 C.F.R. § 193.2013(g).

PHMSA is proposing to amend two existing regulations: (1) 49 C.F.R. § 193.2503, which requires operators of LNG facilities to have written procedures for conducting normal operations and responding to abnormal operations, and (2) 49 C.F.R. § 193.2605, which requires operators of LNG facilities to have written maintenance procedures. PHMSA is also proposing to prescribe two new regulations: (1) 49 C.F.R. § 193.2523, which would require operators of LNG facilities to minimize emissions from blowdowns and boiloff operations, and (2) 49 C.F.R. § 193.2624, which would require operators of LNG facilities to implement new leakage survey requirements. PHMSA is proposing to amend certain provisions in the reporting requirements in 49 C.F.R. Part 191 for LNG facilities as well. The Associations are respectfully providing the following comments on these proposals for PHMSA's consideration.

b) The Risk Assessment for Proposed Amendments to Requirements for LNG Facilities Fails to Satisfy Requirements in Pipeline Safety Act.

The Pipeline Safety Act requires PHMSA to conduct a risk assessment for each pipeline safety standard proposed under 49 U.S.C. § 60102, including standards for

LNG facilities proposed pursuant to 49 U.S.C. § 60103. 49 U.S.C. § 60102(b)(2). In conducting that risk assessment, PHMSA must:

> A. identify the regulatory and nonregulatory options that [PHMSA] considered in prescribing a proposed standard;
> B. identify the costs and benefits associated with the proposed standard;
> C. include—
>   (i) an explanation of the reasons for the selection of the proposed standard in lieu of the other options identified; and
>   (ii) with respect to each of those other options, a brief explanation of the reasons that [PHMSA] did not select the option; and
> D. identify technical data or other information upon which the risk assessment information and proposed standard is based.
>
> *Id.* § 60102(b)(3)(A)–(D).

PHMSA must also make the risk assessment for a proposed standard "available to the general public" for comment and present the risk assessment information to the Gas Pipeline Advisory Committee (GPAC) for peer review as part of the rulemaking process. 49 U.S.C. § 60102(b)(4). Failing to comply with these requirements in developing a proposed standard provides a basis for vacating any standard prescribed in subsequent final rule. *GPA Midstream Ass'n v. United States Dep't of Transportation*, 67 F.4th 1188, 1196-1199 (D.C. Cir. 2023).

The risk assessment that PHMSA prepared for the proposed amendments to Part 193 fails to satisfy the requirements in the Pipeline Safety Act, particularly with respect to the proposed leakage survey requirements in 49 C.F.R. § 193.2624. The PRIA appears to rely on the risk assessment that PHMSA prepared to satisfy the rulemaking mandate in Section 113 in evaluating the proposed regulations for all gas pipeline facilities, including LNG facilities. But the rulemaking mandate in Section 113 does not apply to LNG facilities; it only applies to certain gathering, transmission, and distribution lines. PHMSA does not address this distinction in the PRIA. Indeed, PHMSA does not even discuss the statutory provision that authorizes it to issue safety standards for LNG facilities, 49 U.S.C. § 60103, or address any of the factors that the statute requires it to consider in proposing such standards, including the criteria that specifically apply to operations and maintenance requirements, *id.* at (d).

Nor does PHMSA identify any of the regulatory or non-regulatory options that it considered in conducting the risk assessment for the proposed safety standard for LNG facilities. PHMSA only discusses options relating to the Part 192 regulations for gas pipeline facilities in the PRIA. A risk assessment that does not identify any non-regulatory or regulatory options for the relevant sector of the industry, *i.e.*, LNG facilities, or applicable safety standards, *i.e.*, Part 193, is wholly inadequate. Similarly, PHMSA does not include any information in the PRIA concerning the costs associated with the proposed Part 193 amendments. PHMSA appears to assume that the Proposed Rule will not impose any costs on operators of LNG facilities without articulating a legitimate basis for that assumption. PHMSA also relies almost entirely on technical data and information relating to gas gathering lines, transmission lines, and distribution lines in the PRIA. There is no analysis or discussion of data or information that is relevant to LNG facilities or explanation as to why data and information pertaining to an entirely different sector of the industry provides an appropriate basis for conducting a risk assessment for LNG facilities.

In short, PHMSA failed at the most basic level to conduct the risk assessment that the Pipeline Safety Act requires in developing the proposed Part 193 amendments. The risk assessment described in the PRIA does not satisfy any of the applicable statutory factors and is completely inadequate. PHMSA must prepare a risk assessment that complies with the statute and make that document available for public comment before presenting any of the proposals to the GPAC for peer view. Otherwise, any provisions relating to LNG facilities prescribed in the final rule will be rendered unlawful[220].

3) PHMSA Should Consider Developing Alternative Proposals for Performing Leakage Surveys at LNG Facilities and Minimizing Emissions During Blowdowns and Boiloff Operations

PHMSA is proposing to add a new regulation at 49 C.F.R. § 193.2624 for performing leakage surveys at LNG facilities. The Proposed Rule would, in relevant part, require:

> Each operator of an LNG facility, including mobile, temporary, and satellite facilities must conduct periodic methane leakage surveys, on equipment and components within their facilities containing methane or LNG, at least four times each calendar year, with a maximum interval between surveys not exceeding 4 ½ months, using leak detection equipment. Leak detection equipment must be capable of detecting and locating all methane leaks producing a reading of 5 parts per million or more of within 5 feet of the component or equipment surveyed.

The Proposed Rule would also require LNG operators to have procedures for implementing the leakage survey program, to "maintain records of the leak survey and equipment sensitivity validation and calibration for five years after the leakage survey,"

---

[220] *GPA Midstream Ass'n v. United States Dep't of Transportation*, 67 F.4th 1188, 1196-1199 (D.C. Cir. 2023); Business Roundtable v. SEC, 647 F.3d 1144, 1148–1149 (D.C. Cir. 2011) (finding a regulation to be arbitrary and capricious because "the Commission inconsistently and opportunistically framed the costs and benefits of the rule; failed adequately to quantify the certain costs or to explain why those costs could not be quantified; neglected to support its predictive judgments; contradicted itself; and failed to respond to substantial problems raised by commenters"); *Owner–Operator Indep. Drivers Ass'n v. FMCSA*, 494 F.3d 188, 202–203 (D.C. Cir. 2007) (concluding that "the FMCSA's failure to disclose the cost benefit analysis methodology in time for comment was prejudicial because the petitioners demonstrated that they would have mounted a credible challenged if provided the opportunity to do so")

and to “review the results of the methane leakage surveys and address any methane leaks and abnormal operating conditions in accordance with their written maintenance procedures or abnormal operating procedures.”

As part of conducting the required risk assessment, PHMSA should consider whether to apply the proposed leakage survey requirements in 49 C.F.R. § 193.2624 to LNG facilities that are already subject to leak detection and repair (LDAR) requirements under statutes or regulations administered, or pursuant to permits or authorizations issued, by the U.S. Environmental Protection Agency (EPA) or another federal or state agency. In some cases the LNG facilities have been issued Federal Prevention of Significant Deterioration (PSD) permits specifically to regulate GHG emissions including methane. PSD permits are required to be protective of human health and the environment. PSD regulations require the Best Available Control Technology be applied to control emissions. One aspect of BACT for GHGPSD permits addresses fugitive emissions which includes use of an LDAR program. If an LNG facility is already subject to LDAR requirements that provide adequate protection to public safety and the environment via the underlying air permitting basis, there is no reason for PHMSA to add duplicative, and potentially inconsistent, regulations on that same topic in Part 193. PHMSA’s proposal to include an exemption for compressor stations on gas gathering and transmission lines that are subject to EPA’s LDAR regulations supports the conclusion that regulations in Part 193 are unnecessary for LNG facilities that are subject to comparable provisions under statutes or regulations administered, or pursuant to permits or authorizations issued, by EPA or another federal or state agency.

In addition, PHMSA should consider other approaches in developing any proposed leakage survey requirement for LNG facilities under Part 193. For example:

- Applying the leakage survey requirements to mobile or temporary LNG facilities is unnecessary. Mobile and temporary LNG facilities are often relocated, reconnected, and repressurized, and there is no indication in the record that these non-stationary LNG facilities are a significant source of methane emissions. The Proposed Rule also appears to overlook the exception from Part 193 applicability for mobile and temporary LNG facilities that comply with the standards in 2001 NFPA 59A, which would not be subject to the proposed leakage survey requirements in any event.[221]

- Certain components at LNG plants are inaccessible or unsafe to monitor and other components may be difficult to monitor for leakage survey purposes. PHMSA should either exempt components from the leakage survey requirements that are

[221] 49 C.F.R. § 193.2019(a) (stating, in relevant part, that “[m]obile and temporary LNG facilities for peak shaving application, for service maintenance during gas pipeline systems repair/alteration, or for other short term applications need not meet the requirements of this part if the facilities are in compliance with applicable sections of NFPA–59A–2001”).

inaccessible or unsafe to monitor or allow LNG operators to make that designation in their leakage survey procedures. PHMSA should also allow LNG operators to designate alternative leakage survey intervals in their procedures for components that are difficult to monitor.

- The types of components that are subject to any leakage survey requirements should be clearly identified in any regulation. The definition of component in Part 193 is extremely broad, and there are certainly types of components—or even entire areas or portions of LNG plants—that are not susceptible to leaks. PHMSA should consider whether the leakage survey requirements need to apply to all components and areas within an LNG plant, and, if so, whether these components and areas should be surveyed at less frequent intervals.

- The proposed threshold for the capability of leak detection equipment of 5 parts per million (ppm) or more within 5 feet is unnecessary and unreasonable. Most LNG plants are continuously manned and monitored and have systems capable of detecting any leaks that present a hazard to the plant, personnel, and the public. The record does not justify requiring LNG operators to detect and remediate much smaller leaks at more frequent intervals, particularly at the 5-ppm-within-5-feet standard. That detectability standard is 10,000 times below the lower explosive limit for natural gas, and 100 times more conservative than the comparable requirement in EPA's LDAR regulations. The 5-ppm-within-5-feet standard also prohibits the use of a wide range of commercially available leak detection technologies. Adopting a one-size-that-fits-none approach for leak detection technology does nothing to promote public safety or protect the environment.

- Referring to both "equipment" and "components" in a leak survey requirement for LNG plants introduces uncertainty. The definition of "component" in 49 C.F.R. § 193.2007 already includes "equipment", and 49 C.F.R. § 193.2401, which delineates the applicability of Part 193 to equipment, is limited to "vaporization equipment, liquefaction equipment, and control systems". To avoid uncertainty, the types of components or equipment that are subject to any leakage survey requirements should be clearly specified by regulation.

- The proposed 6-month deadline for complying with the leak survey requirements for LNG facilities is impracticable. LNG operators will need additional time to obtain new permits, acquire new equipment, hire new personnel, and take other actions necessary to achieve compliance.

The following suggested revisions to the Proposed Rule are consistent with these comments:

§ 193.2624 Leakage surveys.

(a) Except as provided in paragraph (e) of this section, ~~E~~each operator ~~of an LNG facility, including mobile, temporary, and satellite facilities~~ must conduct periodic ~~methane~~ leakage surveys~~, on equipment and~~ of designated components ~~within their facilities~~ containing ~~methane~~ gas or LNG~~,~~ at least four times each calendar year, with a maximum interval between surveys not exceeding 4 ½ months, using leak detection equipment. ~~Leak detection equipment must be capable of detecting and locating all methane leaks producing a reading of 5 parts per million or more of within 5 feet of the component or equipment surveyed.~~

(b) Operators must have written procedures providing for each of the following:

(1) Validating the leakage survey equipment and performing leakage surveys consistent with the equipment manufacturer's instructions for survey methods and allowable environmental and operational parameters;

(2) Validating the sensitivity of this equipment ~~by the operator~~ before initial use by testing ~~with a known concentration of gas at a required offset condition of 5 feet~~; ~~and~~

(3) Calibrating the equipment consistent with the equipment manufacturer's instructions for calibration and maintenance. Leak detection equipment must be recalibrated or replaced following any indication of malfunction; and~~.~~

(4) Designating the components subject to the periodic leakage survey requirements, not including any components that are inaccessible, unsafe to monitor, or difficult to monitor during one or more survey intervals.

(c) Each operator must maintain records of the leak survey and equipment sensitivity validation and calibration for five years after the leakage survey.

(d) Operators must review the results of the methane leakage surveys and address any methane leaks and abnormal operating conditions in accordance with their written maintenance procedures or abnormal operating procedures.

(e) The requirements in this section do not apply to:

(1) An LNG facility subject to a leak detection and repair program pursuant to a statute or regulation administered, or a permit or authorization issued, by the U.S. Environmental Protection Agency or another federal, state, or local agency; or

(2) A mobile or temporary LNG facility.

E. Investigation of Failures—§ 192.617

Operators have historically made considerable efforts to identify and understand the cause of pipeline failures, as well as other unintended releases of gas such as leakage and malfunction of pressure relief devices. These causal analyses have been critical to compliance with incident and annual reporting requirements defined in § 191.3, as well as identification of systemic threats to pipeline integrity and prevention of similar events in the future. While the Associations recognize the potential clarity provided by codifying when investigations are needed, significantly expanding the definition of "failure" as regards § 192.617 is counterproductive to prioritizing and mitigating risk.

As PHMSA acknowledges on page 31951 of Federal Register of the NPRM, "*PHMSA already references ASME/ANSI B31.8S's functional definition of a failure in the instructions for gas transmission and regulated gathering pipeline annual reports*." The cited definition of failure in PHMSA's instructions "*is defined in ASME/ANSI B31.8S as a general term used to imply that a part in service: has become completely inoperable, is still operable but is incapable of satisfactorily performing its intended function; or has deteriorated seriously, to the point that it has become unreliable or unsafe for continued use*." Individual leaks generally do not render a pipeline (in whole or in part) either "completely inoperable," "incapable of satisfactorily performing its intended function," or "unreliable or unsafe for continued use." Therefore, while some failures occur as the result of leakage, not all instances of leakage are pipeline failures[222]. This is consistent with the ASME/ANSI B31.8S definition, which distinguishes between "failure" and "leakage" in various instances, and furthermore relates failures to pipe strength, not typical of most leakages.

Operators will continue to evaluate leak cause at a system level, which is much more practicable and logical than the extensive requirements for investigating every failure as proposed in § 192.617. For instance, the cause of gas distribution leaks is determined in an Operators' DIMP program (i.e. Subpart P). DIMP requires an operator to know and understand its system as well as develop actions to mitigate risk, which includes actions to reduce the number of leaks. As stated previously, a leak generally does not affect the operability of the pipe or its ability to perform its intended function reliably and safely.

Conducting a failure investigation as prescribed by § 192.617 is resource intensive. Increasing the number of investigations required by § 192.617 by orders of magnitude, to include leaks which have not meaningfully resulted in a failure, will divert attention from investigations of pipeline failures. As a part of Integrity Management, transmission and distribution operators do perform incident investigations on events involving material or equipment failures, and even near-misses. These incident investigations typically take weeks and result in recommendations for the operator to implement.

The application of ASME/ANSI B31.8S in defining failures is appropriate, as it defines certain leaks as failures without making "leak" and failure" synonymous. However, failure

[222] While failures (per § 192.617) are not synonymous with incidents (per § 191.3), this NPRM acknowledges that the percentage of total gas distribution leaks resulting in reportable incidents is less than 0.007% (see FR page 31910). This goes some way to quantifying the relative severity of gas distribution leaks as regards pipeline safety and the appropriate allocation of causal investigation resources.

criteria should also be clarified as being tied to an event, so as not to associate the intended end of a pipeline's life (e.g. for capacity or reliability reasons) with "failure."

The proposed edits to the regulatory text of § 192.617 provide language that clarifies the definition of "failure" to reflect historical understanding of the term, and to ensure the identification of legitimate pipeline failures (and, critically, resourcing and prioritization of the associated investigations) is not obscured and crowded out by an unmanageable number of non-failure leakages.

It should be noted that PHMSA did not consider the costs, benefits, or other impacts of the proposed definition of a failure in preparing the risk assessment for the Proposed Rule. The PRIA states that the Agency assumed that the definition was consistent with existing industry standards and would not result in any additional compliance costs or benefits. That assumption is invalid as the proposed definition of a failure departs from the ASME/ANSI B31.8S definition in several respects. PHMSA must revise the definition of a failure in the final rule to align with existing industry standards, including the provisions in ASME/ANSI B31.8S, to satisfy the risk assessment requirements in the Pipeline Safety Act.

The associations suggest the language in § 192.617 to be revised as shown below:

§ 192.617 Investigation of failures and incidents

………

(e) Failure defined. For the purposes of this section, the term failure means ~~when~~ an event in which any portion of a pipeline becomes completely inoperable, is incapable of ~~safely~~ satisfactorily performing its intended function, or has become unreliable or unsafe for continued use.

F. Design, Configuration, and Maintenance of Pressure Relief Devices—§§ 192.9, 192.199 and 192.773

Note: § 192.739 is cited as the proper code section for the proposed requirements in § 192.773 in the Associations' suggestions

The Associations understand and generally support the basis for additional requirements proposed for pressure relief devices; however, there are some significant concerns that may render some of the language impracticable and overly burdensome. PHMSA is also encouraged to bear in mind that operators do already design, install and maintain pressure relief devices in a manner to ensure gas is delivered safely and reliably and each actuation is reviewed closely, with the intent to determine if any changes are warranted.

Section 192.199 reflects PHMSA's belief, as noted in the preamble, that operators need to adjust their settings so that "unnecessary" releases from relief valves to the atmosphere no longer occur. PHMSA believes the industry has under-reported the number of incidents involving overpressure activations for significant volumes of gas released. Relief valve releases are a necessary and fundamental occurrence in ensuring pipeline safety.

The Associations do not believe operators design their system to capriciously release gas into the atmosphere; it is always done in the interest of preserving public safety and protecting against the risk of over-pressurization. <u>It is a necessary safety measure in the delivery of natural gas.</u> Furthermore, there is no incentive for operators to design and configure relief valves to vent unnecessarily, given the cost, personnel, and potential for public nuisance associated with blowing relief valves.

Based on the tone of the language in the NPRM preamble, it appears there is a general lack of understanding of the events that are associated with a blowing relief valve. Note that the Associations understand and support the notion that operators may need to revisit their settings and adjust them, as needed, to ensure that all trips on relief valves are necessary, but there will always be a margin that is unique to each operator's system and the local operating conditions. Operators are very intentional on how individual pressure relief devices are managed throughout the year.

The Associations have submitted suggested changes to clarify that requirements in § 192.199 would generally apply to new or replacement jobs involving relief pressure devices, which aligns with the scope of Subpart D. The proposed language appearing under the newly-proposed § 192.773 should actually be incorporated into existing § 192.739 within Subpart M since it broadens the scope of inspection and testing to include requirements for maintenance and record-keeping, which naturally fit together. In addition, the reasoning for the suggested changes to the code language are based on the following justifications:

- The proposed requirement to repair or replace "as soon as practicable but within 30 days" when an activation occurs at a pressure below the set point creates several different problems. In the situation where replacement is required when the device "releases gas below the set pressure range," it will typically take more than 30 days to redesign the facility, order and receive the parts, and complete installation. This timeframe is excessive for a situation that is not jeopardizing public safety. (This is a relief valve that has started relieving below the set point so overpressure is not the concern). This may force the operator to have numerous spare pressure relief devices of various characteristics (based on pressure range and system requirements) on hand, which creates additional challenges for no added safety benefit. Extra time should be allowed to properly engineer and determine the long-term solution.

- Related to this concern, the language in the proposed § 192.773(a)(3)(ii) is having to "take immediate and continuous action with on-site personnel to stop the release." Although measures would be taken to eliminate or minimize the release, it may not always be possible to achieve quickly, and in any case these releases are not necessarily an immediate threat to people or property. The language, if promulgated, could require operators to remain on site for up to 30 days, which is not feasible. In many cases, the only remaining option is to shut gas to the station and curtail service to customers for the duration of repairs, or the amount of time required to acquire a replacement relief device. Curtailing service is never a good option for an operator, unless public safety is directly threatened.

- "Malfunction" and "mis-configuration" may be confused in how they are presented in the regulatory context. Mis-configuration generally suggests poor design or installation. Malfunction suggests a performance issue with the valve/regulator. This distinction is important to maintain in code requirements and our proposed language seeks this clarification.

- "Documented engineering analyses" is not a reasonable term to include within 192.199 because it is overly vague and subject to countless interpretations on what kind of information is required. The associations recognize there is some amount of information that would be appropriate to require in the design; therefore, we have provided edits which establish a reasonable expectation that an operator maintain documentation for new or reconfigured assets on how they were designed and what basis was used during the design stage. PHMSA proposes that Engineering analyses must include, among other things, that "*the pressure relief device and its associated piping must be appropriate for its set and reset actuation pressure to minimize pressure choking….*"[223] Choked flow conditions at relief valve outlet are often unavoidable. Properly sized relief devices and its associated piping can operate as intended even if flow is choked in the outlet piping. PHMSA should remove "engineering analyses" and "pressure choking" in the regulatory language.

- The monitor control setting is set at a pressure to ensure that the station outlet does not exceed MAOP plus allowable build up. In some cases, operators use a combination of monitor control and full relief to ensure there are additional layers of overpressure protection. The actual configuration may vary by operator and even by individual installation. It is important to preserve that ability to set the monitor at an appropriate pressure based on the operators' experiences and knowledge of the system, and what is being protected downstream.

- Isolation valves are not always necessary both upstream and downstream of the relief valve to facilitate testing or inspection. Operators may test relief valves by closing an upstream isolation valve and using compressed nitrogen to increase pressure in the isolated segment just to the point when the relief valve begins to open. This practice alone limits emissions. Installation of unnecessary valves will increase installation and maintenance costs without discernible benefit. Operators must have the flexibility to design the relief valve configurations to optimize isolation and maintenance.

[223] 88 Fed. Reg. at 31,973.

- Operators may not always know immediately when a relief valve has been activated below its set actuation pressure range, depending on the SCADA monitoring that is in place among those assets. The Associations believe operators can only be held accountable for taking required actions when they have this knowledge after confirmed discovery.

The Associations suggest the following changes be made to § 192.199:

§ 192.199 Requirements for design and configuration of pressure relief and limiting devices.

* * * * *

(e) Have discharge stacks, vents, or outlet ports designed to prevent accumulation of water, ice, or snow, located where gas can be discharged into the atmosphere without creating a potential hazard ~~undue hazard~~ to public safety;

* * * * *

(i) All new, ~~replaced~~ or reconfigured, ~~relocated, or otherwise changed~~ pressure relief and limiting devices must be designed and configured, ~~as demonstrated by~~ with documentation, ~~a documented engineering analysis~~, to ~~minimize unnecessary releases of gas by ensuring each of the following:~~ activate when needed, in order to preserve public safety. Additional criteria for operators are as follows:

(1) The set and reset actuation pressure of the pressure relief device and where pressures are taken must limit necessary ~~minimize~~ release volumes. ~~beyond what is necessary to provide adequate overpressure protection;~~

(2) The design (including sizing and material) and configuration of the pressure relief device and its associated piping must be appropriate for its set and reset actuation pressure ~~to minimize pressure choking~~, compatible with the composition of transported gas, and suitable ~~for reliable operation~~ in expected operating and environmental conditions; and

(3) Installation of the pressure relief device must include ~~upstream and downstream~~ isolation valve(s) to facilitate testing and maintenance.

§ 192.739 Pressure limiting and regulating stations: Inspection, ~~and~~ testing, maintenance and records.

(a) Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is—

(1) In good mechanical condition;

(2) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

(3) Except as provided in paragraph (b) of this section, set to control or relieve at the correct pressure consistent with the pressure limits of § 192.201(a); and

(4) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

If a malfunction is discovered, operators shall address paragraphs (c), (d) and (e).

(b) For steel pipelines whose MAOP is determined under § 192.619(c), if the MAOP is 60 psi (414 kPa) gage or more, the control or relief pressure limit is as follows:

If the MAOP produces a hoop stress that is:	Then the pressure limit is:
Greater than 72 percent of SMYS	MAOP plus 4 percent.
Unknown as a percentage of SMYS	A pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP.

(c) Each operator must develop, maintain, and follow written operations and maintenance procedures to ~~assess~~ evaluate the proper function of pressure limiting or relief device and to repair or replace each ~~failed~~ pressure limiting or relief device, wherever one is found to have malfunctioned. When a pressure limiting or relief device fails to operate or allows gas to release to the atmosphere at an operating pressure above or below the set actuation pressure range defined for the device in the operator's operations and maintenance procedure, the operator must:

(1) ~~Assess the pilot, springs, seats, pressure gauges, and other~~ Evaluate relief device components to ensure proper functioning, sensing, and set/reset actuation pressures are within actuation pressure tolerances;

(2) ~~Assess~~ Evaluate the inlet and outlet piping for piping that restricts the inlet or outlet gas flow, piping that restricts the sensing pressure, and evaluate for debris~~, and~~ or other restrictions that could impede the operation or restrict the capacity to relieve overpressure conditions;

(3) Repair or replace the device to eliminate the malfunction as follows:

(i) If a pressure relief device activates above its set pressure and above the pressure limits in § 192.201(a) or 192.739(b) as applicable, fails to operate, or otherwise fails to provide overpressure protection, the operator must take immediate ~~and continuous~~ action to address the issue ~~upon discovery.~~ The repair or replacement of the device or pressure sensing equipment should occur as soon as practicable. ~~immediately.~~

(ii) If an operator learns a pressure relief device allows gas to release to the atmosphere at an operating pressure below the set actuation pressure range, the operator must take immediate ~~and continuous~~ action to address the issue with on-site personnel to stop the release until the device is repaired or replaced. Repairs should occur ~~The relief device or pressure sensing equipment must be repaired or replaced~~ as soon as practicable. ~~but within 30 days.~~

(d) Each operator must develop, maintain, document, and follow written operations and maintenance procedures to ensure that a pressure relief device configuration~~, as demonstrated supported by a documented engineering analysis,~~ employs set and reset actuation pressures ensuring limitation ~~minimization~~ of release volumes, while still providing ~~adequate~~ necessary overpressure protection.

(e) Records under this section must be maintained as follows:

~~(1) Records of relief devices malfunctions must be maintained for 5 years after repair or replacement.~~

~~(2) Records pertaining to repair, replacement, or reconfiguration (including any engineering analyses) of a pressure relief device must be maintained for the life of the pipeline.~~

Records of malfunctions, as well as method of repair, replacement, or reconfiguration, shall be maintained for 5 years.

G. Qualification of Leakage Survey, Investigation, and Repair Personnel—§ 192.769

Operator Qualification is adequately addressed through Subpart N

The Associations support Operator Qualification requirements for covered tasks associated with leak surveying, leak grading, and leak repair. However, for natural gas transmission, distribution pipelines, and Type A gathering lines, the associations believe PHMSA's proposed § 192.769 is duplicative and unnecessary. Leak survey, grading, and repair currently meet the 4-part test per § 192.801(b). Each of these activities occurs on a pipeline facility, is an operations and maintenance ask, will be required by pipeline safety regulation, and impact the operation and integrity of the pipeline.

According to the PRIA, PHMSA "proposes to clarify training and qualification requirements for personnel that conduct leakage surveys, investigation, and leak grading on gas transmission, distribution, offshore gathering, and Type A gathering pipelines." If only intended to be a clarification, the Associations believe its addition is not necessary, is ultimately duplicative, and could create regulatory confusion.

PHMSA also fails to address the unintended consequence of this proposal. By stating that "Only individuals qualified under Subpart N may conduct leakage survey, investigation, grading, and repair", PHMSA has eliminated an important provision in Subpart N that "allows individuals that are not qualified pursuant to this subpart to perform a covered task if directed and observed by an individual that is qualified."[224] PHMSA has not addressed this elimination in the proposed rule or accounted for its impact in the PRIA.

The Associations also remind PHMSA that training documentation is not a current regulatory requirement, regardless of PHMSA's Operator Qualification Frequently Asked Questions (FAQs) published on January 28, 2022. Part 192 requires operators to qualify individuals performing covered tasks, but there is no regulatory requirement to provide *training* for leak survey, leak grading, and leak repair tasks. The code provides flexibility in that operators must provide *training as appropriate.* Training "as appropriate" allows operators to provide training when needed for individuals on a case-by-case basis. It does not require operators to document specific initial training and refresher training for all employees. Training and qualification are two separate programs but proposed § 192.769 seems to conflate these activities.

In the Accountable Pipeline Safety and Partnership Act of 1996, Congress explicitly clarified that the regulatory requirement is for qualification of personnel and not training. Congress struck "training and certification" from the law and replaced it with "qualification[225]." It was this mandate that ultimately led to PHMSA's OQ rule in 1999. Moreover, in accordance with 49 C.F.R § 5.85, new training requirements can only be mandated through the formal rulemaking process.

The second sentence in PHMSA's proposed § 192.769 "Individuals qualified under subpart N must also possess training, experience, and knowledge in the field of leakage survey, leak investigation, and leak grading, including documented work history or training associated with those activities" may lead to confusion as to whether the covered tasks addressed through this proposal are being held to a different standard than all other covered tasks governed by Subpart N. At a minimum, PHMSA should strike the second sentence.

Lastly, PHMSA includes the concept of "leak investigation" into pipeline safety regulations in at least two instances in this rulemaking: § 192.769 and § 192.760(i)(1). While commonly used by gas distribution pipeline operators to describe their operations & maintenance activity, absent a definition or distinction between leak survey, leak investigation, and leak grading in 49 Part 192, the Associations recommend that PHMSA abstain from using the term "leak investigation" in regulations.

The Associations recommend the proposed addition of § 192.769 be removed.

[224] 49 CFR 192.805(c)
[225] Accountable Pipeline Safety and Partnership Act of 1996, Sec. 4 - General Authority (October 12, 1996).

~~**§ 192.769 Qualification of leakage survey, investigation, grading, and repair personnel.**~~

~~Only individuals qualified under subpart N of this part may conduct leakage survey, investigation, grading, and repair. Individuals qualified under subpart N must also possess training, experience, and knowledge in the field of leakage survey, leak investigation, and leak grading, including documented work history or training associated with those activities.~~

H. *Mitigating Vented and Other Emissions From Gas Pipeline Facilities—§§ 192.9, 192.12, 192.605, 192.770, 193.2503, 193.2523 and 193.2605*

1) Mitigating Vented Emissions from Gas Pipeline Facilities

PHMSA proposes that when an operator conducts any intentional release of gas, including blowdowns or venting for scheduled repairs, construction, maintenance, and operations tasks, it must reduce the release of gas to the environment through one of six proposed methods. Those methods include (1) isolating the smallest section of the pipeline needed to complete the task; (2) routing gas from the nearest isolation valve or control fitting to a flare as fuel gas; (3) reduce the pressure by using in-line compression; (4) reduce the pressure by using mobile compression; (5) transfer the gas to a segment of a lower pressure pipeline system adjacent to the nearest isolation valve; or (6) employ an alternative method which will result in a release volume reduction of at least 50% compared to venting gas directly to the atmosphere.[226]

(a) PHMSA should clarify that operators are required to reduce emissions using the methods specified in § 192.770.

The Associations support PHMSA's intention to provide a menu of options for mitigating vented emissions, as specified in § 192.770(a)(1)-(6). This flexibility is critical, given the significant variability in cost, safety, and system considerations. However, as written, it may be concluded that operators must "minimize" emissions by selecting the method in § 192.770(a) (including "alternative" methods) that achieves the greatest emissions mitigation, to the exclusion of all other methods. This is unreasonable and in contradiction of PHMSA's intention[227] to provide a menu of proven options for operators to select from. Accordingly, the text of §§ 192.770, 192.605(b)(13), and 193.2523 should be revised to require operators to "reduce" emissions.

[226] 88 Fed. Reg. at 31,978.
[227] *Id.*, at 31,948.

(b) PHMSA should limit the applicability of § 192.770 (and § 193.2523) to planned releases that would exceed 1 MMCF without mitigation.

In the NPRM, PHMSA requests comment on whether it is appropriate to specify a minimum pressure reduction for the vented segment. There are many factors that PHMSA should consider when determining the quantity of a pressure reduction for a vented segment. PHMSA should factor in outage time, impact to customers, impact to communities, costs, and the time needed to begin the pressure reduction.

If PHMSA's goal is to reduce emissions, then it should focus on reducing large-volume releases. Applying these requirements to *all* planned venting, including the smallest measurable volumes (several orders of magnitude smaller than PHMSA's proposed definition for large-volume gas releases), is impractical, onerous, and would treat each planned venting as being of equivalent concern regarding methane emissions impact. Compliance would be particularly difficult and costly for relatively low-pressure systems where recompression or drawdown technology may not be able to operate.

PHMSA should focus on reducing emissions in absolute terms by modifying proposed § 192.770 (and § 193.2523) to apply only to planned releases that would exceed 1 MMCF without mitigation.

(c) PHMSA should expand the exception for emergencies to include safety risk and commercial impacts.

The agency has proposed one exception to the provisions in proposed section 192.770(a)(1)-(6). PHMSA limits the exception to emergencies.[228] There are several potential events where an operator might be faced with a safety risk to its personnel, contractor, customers, general public, or landowners and need to vent the gas immediately. PHMSA should also consider situations where a pipeline is the only source of gas for a community and whether waiting for mobile compression equipment is the appropriate response, rather than venting the gas to perform the necessary maintenance. PHMSA should further consider offshore platforms where there is not space to install a flare, and location makes getting temporary equipment to the site; a time-consuming proposition. While rare, offshore gas lines can develop hydrate plugs that require venting of the line to remedy. A single offshore gas pipeline shut down can block in up to 250,000 barrels of production per day, and a hydrate left in a line for an extended period of time can lead to pipeline integrity issues. For both of these reasons, a quick clearing of a hydrate block is essential but may not be feasible if flaring provisions must be made. The Associations recommend expanding the proposed exception to include safety risks in the judgment of the operator and potential commercial impacts.

[228] Proposed Section 192.770(b).

(d) PHMSA should not restrict the use of flaring.

In the NPRM, PHMSA proposes to restrict the use of flaring. Flaring can reduce the effect of emissions on climate change by up to 25 times. Based on experience, flaring with 95% flare efficiency is thought to reduce the global warming potential (GWP) of an emission by almost 91%, relative to unmitigated venting. Considering PHMSA proposes in Section 192.770 to accept a 50% reduction in the vent volume as a sufficient threshold for an emission reduction method, flaring should still be acceptable as a primary method to reduce the emissions. Restricting the use of flaring to instances where other measures are impracticable will cause a higher cost to operators and may actually cause more harm than good to the environment. Furthermore, such a restriction may be contrary to state and environmental regulations and existing permit conditions.

(e) PHMSA should clarify the documentation requirements to be satisfied through written procedures.

PHMSA is proposing to require that operators use certain methods to prevent or minimize the release of gas to the environment during intentional releases, such as blowdowns or venting for scheduled repairs, construction, operations, or maintenance activities. The Agency is also proposing to require that operators document the methodologies used in satisfying these requirements. PHMSA should clarify that the documentation requirement can generally be satisfied through the development and implementation of written procedures that apply to the pipeline. There is no need for operators to document the application of the methodologies used to reduce the release of gas during each specific intentional release that occurs on a pipeline. Such a requirement would impose undue recordkeeping burdens, particularly when applied to routine activities that involve small, intentional releases of gas, such as pigging or meter run activities.

(f) Operators will need more time than six months to make preparations for compliance with Section 192.770.

PHMSA proposes a six-month effective date for the final rule in this proceeding. As discussed later in this comment document, the Associations recommend a longer timeframe to begin implementation of new rule requirements. The natural gas industry will require additional time to evaluate applicable control measures to mitigate or reduce methane emissions on transmission pipelines using the proposed techniques. For example, operators will need to address the following considerations prior to purchase or rental of temporary compression units: mechanical capability, infrastructure siting, air compressor or compressor power, liquids management, equipment and hose maintenance, fleet size - unit per yard, rental availability, transportability, flexibility, smaller diameter piping, runtime, downtime, efficiency, flow capacity, system planning integration and standardization of tracking volume estimates. For flaring, operators will need to assess: siting infrastructure, transportability, adjustable height, trailer tag, hydrocarbon destruction percentage, state and federal environmental requirements.

The agency is expecting operators to have mobile compression on standby when each operator conducts operations, maintenance, and repair activities that require an intentional release of gas. This is not realistic or practical. Many transmission ROWs are in remote locations and there can be a delay to secure mobile compression at the scene. The Associations are also concerned that the mobile compression companies are not ready to accommodate the significant increase in demand and will need more time to ramp up operations.

The Associations provide the following changes to the regulatory text in Parts 191 and 192 for PHMSA's consideration:

§ 192.770 ~~Minimizing~~ Reducing emissions from gas transmission pipeline blowdowns.

(a) Except as provided in paragraph (b) of this section, when an operator performs any intentional release of gas that would exceed 1 MMCF without mitigative action (including blowdowns or venting for scheduled repairs, construction, operations, or maintenance) from a gas transmission pipeline, the operator must prevent or ~~minimize~~ reduce the release of gas to the environment through one or more of the following methods:

(1) Isolating the smallest optimal section of the pipeline necessary to complete the task by use of valves or the installation of control fittings;

(2) Routing gas released from the pipeline from the nearest isolation valves or control fittings to a flare or to other equipment as fuel gas;

(3) Reducing pressure by use of inline compression;

(4) Reducing pressure by use of mobile compression to a segment or storage vessel adjacent to the nearest isolation valves;

(5) Transferring the gas to a segment of a lower pressure pipeline system adjacent to the nearest isolation valves; or

(6) Employing an alternative method demonstrated to result in a release volume reduction of at least 50% compared to venting gas directly to the atmosphere without mitigative action.

(b) An operator is not required to comply with the provisions of paragraph (a) of this section during an event that ~~activates its emergency plan under § 192.615(a)(3) when such minimization~~ would delay emergency response, or, in the judgment of the operator, would result in a safety risk or impact to customers or production operators ~~during pipeline assessments or maintenance~~. Each ~~emergency~~ release conducted without mitigation must be documented, including the justification for release without mitigation.

~~(c) Operators must document the methodologies used in paragraph (a) of this section and describe how the methodologies minimize the release of gas to the environment.~~

§ 192.605 Procedural manual for operations, maintenance, and emergencies.

(b) * * *

* * * * *

(13) Eliminating leaks in accordance with leak repair schedules specified in § 192.760 and ~~minimizing~~ reducing releases of gas from pipelines, as well as remediating or replacing pipelines known to leak based on their material, design, or past operating and maintenance history.

2) Mitigating Vented and Other Emissions from LNG Facilities

PHMSA should consider alternative proposals for minimizing emissions during blowdowns and boiloff operations as well. For example, the proposed requirement in 49 C.F.R. § 193.2523(a)(1) to isolate a "smaller section of the piping segment" is vague, and the term "control fitting" is not defined in Part 193. Nor is the proposed six-month implementation period provided for the proposed leakage survey requirements reasonable. Operators of LNG facilities may need to obtain new or modified air permits to route additional volume to flare, and such actions can take years to complete. Any proposal for minimizing emissions during blowdowns and boiloff operations must account for the time needed to obtain the necessary permits.

The following suggested revisions to the Proposed Rule are consistent with these comments:

§ 193.2523 Reducing ~~Minimizing~~ emissions from blowdowns and boiloff.

(a) Except as provided in paragraph (b) of this section, an operator of an LNG facility must reduce ~~minimize~~ intentional emissions of natural gas from LNG facilities that would exceed 1 MMCF without mitigative action, including tank boiloff or blowdowns for repairs, construction, operations, or maintenance. The operator must reduce ~~minimize~~ the release of natural gas to the environment by use of one or more of the following methods:

(1) Isolating ~~a smaller section of the~~ piping segments by use of valves or the installation of control fittings;

(2) Routing gas released from the facility to a flare, or to other equipment for use as fuel gas;

(3) Transferring gas or LNG to a storage tank or local pressure vessel; or

(4) Employing an alternative method demonstrated to result in release volume reductions of at least 50% compared to venting gas directly to the atmosphere without mitigative action.

(b) An operator is not required to comply with the provisions of paragraph (a) of this section during an emergency resulting in the activation of their emergency procedures under § 193.2509. An operator must document each emergency release without mitigation described in paragraph (b) of this section, including the justification for release without mitigation.

(c) The operator must document the method or methods used and describe how those methods reduce ~~minimize~~ the release of natural gas to the environment.

I. Reporting—§§ 191.3, 191.9, 191.11, 191.17, 191.19, and 191.23

1) Large-Volume Gas Release Reporting

PHMSA is proposing to amend 49 C.F.R. Part 191 to require operators to submit reports on large-volume gas releases. The Agency is proposing to define a large-volume gas release for these purposes as "an intentional or unintentional release of 1 million cubic feet or more of gas from a gas pipeline facility as that term is defined in § 192.3." These reports would need to be submitted "within 30 days after detection of a large-volume gas release,'" unless "an incident report has already been submitted under [49 C.F.R. Part 191] for the same event and the release volume identified in the incident report is within 10 percent of the total release volume on cessation of the release."[229]

The proposed definition of large-volume gas release does not specify whether an intentional flaring event would constitute a release. The proposed requirements for minimizing emissions from gas blowdowns in § 192.770 imply that flaring does not qualify as a release of gas, as flaring is listed as an alternative to blowdown and venting in that proposal. PHMSA should clarify the definition of a large-volume gas release in the final rule to state that a release of gas does not include gas that is burned through flaring or consumed as fuel.

PHMSA should also reevaluate its estimated paperwork burdens to complete such reports, adjust the deadline for filing the reports, and clarify that incident reports and large-volume gas release reports are parallel but separate efforts.

a) PHMSA's methodology for calculating the number of Large-Volume Gas Release Reports per year is not clear.

PHMSA acknowledges that it "does not have information on the current number of leaks between 1 and 3 MMCF."[230] In the NPRM, PHMSA estimates that it would receive

[229] 88 Fed. Reg. at 31954.
[230] PRIA, at 51.

373 total reports on average each year, including 134 for transmission.[231] In the Preliminary Regulatory Impact Analysis (the PRIA), the agency estimates that it would receive 393 total reports per year (139 reports for transmission).[232] PHMSA calculates these figures by estimating that 8% of 1,740 leaks (defined as the average number of leaks reported between 1 MMCF and 3 MMCF) would qualify as a large-volume gas release.[233] PHMSA has not explained its rationale for using 8%. The agency stated that it assumed 8 percent is the correct figure based on "incident reports of unintentional releases of natural gas between 1 and 3 MMCF."[234] PHMSA did not provide any supporting data to support its use of 8%. The Associations cannot provide meaningful comment without understanding PHMSA's analysis.

b) PHMSA should review its estimate of the burden to complete each Large-Volume Gas Release Report.

PHMSA's estimate of the burden (time, effort, and financial resources)[235] involved in completing a Large-Volume Gas Release Report is not clear and, at times, inconsistent. The agency has an obligation to engage in a "specific, objectively supported estimate of [the] burden" imposed by a proposed information collection.[236] PHMSA must analyze the time and cost to (1) review instructions; (2) develop, acquire, and install technology to collect, verify, and process the requested information; (3) train personnel; (4) search existing data sources; (5) complete the form; and (6) submit the information to the agency.[237] In the Proposed Rule, PHMSA estimates that it will take an operator only four hours to complete these tasks.[238] In the PRIA, the agency provides a different burden estimate indicating that it will take each operator twelve hours.[239]

Each operator will need sufficient time to acquire the necessary technology, train personnel, evaluate the leak, perform calculations, respond to PHMSA and state inquiries, and complete the report. PHMSA should reevaluate its cost assessment for completing these reports and publish a risk assessment that explains it use of the 8%, how it calculated the projected number of reports that will be filed and ensure that it has included all of the steps needed to complete such an information collection.

c) PHMSA should use technology to reduce the burden of this information collection.

---

[231] 88 Fed. Reg. at 31,967.
[232] PRIA, at 51.
[233] *Id*., at 51.
[234] *Id.*
[235] 5 C.F.R. § 1320.3(b)(1).
[236] 5 C.F.R. § 1320.8(a)(4).
[237] 5 C.F.R. § 1320.3(b)(1)(i)-(ix).
[238] 88 Fed. Reg. at 31,967.
[239] PRIA at 51.

PHMSA should consider modifying its collection method to reduce the burden. The agency is required to assess whether the burden on paperwork collection respondents can be reduced through technology.[240] The agency should consider using a tabular reporting process within the PHMSA Portal for Large-Volume Gas Releases. By using a table that could be consistently updated, operators could populate and revise the data more efficiently. This type of approach would decrease the paperwork burden compared to requiring operators to create individual stand-alone submissions. The Associations request that PHMSA consider these comments and reevaluate its burden estimate to confirm that it complies with 5 C.F.R. Part 1320.

(d) PHMSA should use the date of discovery for determining when a leak started.

The agency provides in the NPRM that "[i]f the time the leak started is unknown, operators should base the calculation based on estimated release volume from the date of the most recent leakage survey."[241] PHMSA provides no support for this position and only makes this statement in the preamble. The agency does not include this language in the proposed Instructions for the Large- Volume Gas Release Report. The purpose of reporting requirements is to collect accurate data. Requiring an operator to calculate the estimated release volume from the date of its last leakage survey will produce unsupportable data.

PHMSA should use the date the leak is discovered as the start date for a leak, not the last leakage survey.[242] The date of the first indication of a verified leak is a far more reliable indicator of leak start date than the date of the last leakage survey. Given consistent work at pipeline facilities and in the right-of-way and odorization requirements for certain pipelines, it is far more likely that a leak began when it was first detected than at the time of the last survey date. PHMSA should clarify in its instructions for the Large-Volume Release Report that if the time the leak started is unknown, operators should base the calculation on the estimated release volume from the date of the first indication of the leak.

(e) PHMSA should clarify an operator can file a supplemental incident report rather than require both a Large-Volume Gas Release Report and an Incident Report.

Incident reports and Large-Volume Gas Release Reports should be used as parallel but separate efforts. In proposed Section 191.19, PHMSA states that if events are reported as incidents, an operator would still need to file a Large-Volume Gas Release Report if the total release volume "at cessation exceeds 10% of the volume estimates

---

[240] 5 C.F.R. § 1320.8(a)(5).
[241] 88 Fed. Reg. at 31,955 (emphasis added). PHMSA states in the Proposed Rule that "if the time the leak started is unknown, operators should base the calculation based on estimated release volume *from the date of the most recent leakage survey*."
[242] *Id.*

in the incident report."[243] This is contrary to the agency's position in the preamble that a Large-Volume Gas Release report fills a gap in incident reporting and will serve as a parallel effort.[244]

Requiring operators to file both reports is also inconsistent with Paperwork Reduction Act requirements. Agencies must demonstrate that information collections are "the least burdensome necessary," "not duplicative of information otherwise accessible to the agency," and "ha[ve] practical utility."[245] If the volume estimate needs to be updated, an operator should file a supplemental incident report. There is no need to also file a Large-Volume Gas Release Report. This approach would lead to duplicative reporting and is overly burdensome.

(f) PHMSA should allow operators to rescind a Large-Volume Gas Release Report if it subsequently meets the incident definition in § 191.3.

PHMSA states in the NPRM that "if an unintentional release reported as a large-volume gas release report subsequently becomes reportable as an incident due to updated release volume estimates or consequences (or for any other reason), the operator would have to resubmit it as an incident report appropriate for the facility type."[246] The Associations understand that reasoning but request a process for the operator to rescind the Large-Volume Gas Release Report for the same event.

(g) PHMSA should modify the proposed Large-Volume Gas Release Reporting requirements to avoid unnecessary overlap with LNG EPA/state reporting.

PHMSA is proposing to require LNG operators to submit large-volume gas release reports. While the industry is not opposed to providing such information, most qualifying large-volume gas releases at LNG facilities are already reported to EPA or state programs acting pursuant to authority delegated by EPA. PHMSA should provide an exemption to the reporting requirement for large-volume gas releases that are reported to these authorities to avoid imposing duplicative and unnecessary reporting requirements.

2) Annual Reports

(a) PHMSA should update its paperwork burden estimate associated with completing an Annual Report.

PHMSA states in the PRIA that the existing paperwork burden for Part 192-regulated gathering and transmission pipeline annual reports is 21.5 hours and that the proposed

---

243 88 Fed. Reg. at 31,955.
244 *Id.* at 31,967.
245 5 C.F.R. § 1320.5(d)(1).
246 88 Fed. Reg. at 31,955.

modifications to the annual report would increase the burden by six hours.[247] However, the Office of Information and Regulatory Affairs recently reviewed and approved changes to this form and PHMSA had noted in that submission that the burden per report for each transmission operator is expected to be 47.5 hours.[248] If the six hours to complete the modifications noted in the NPRM is correct, then the burden should be 53.5 hours or more.

(b) The agency should reconsider its proposed deletions in Part M1 of the Annual Report Instructions.

In Part M1 of the instructions to the Annual Report, PHMSA proposes to eliminate the important and necessary clarification that if a non-hazardous release can be eliminated by lubrication or tightening, it is a not a leak.[249] PHMSA also proposes to remove the definition of a leak.[250] As discussed in these comments, releases that can be eliminated by routine maintenance should not be considered leaks. Adding these types of releases to the leak definition would significantly increase the burdens in reporting with little to no associated benefit.

(c) Definition of "leak" and "hazardous leak" in Annual Report instruction

Part C of the Gas Distribution Annual Report (and similarly, Part M of the Gas Transmission & Gathering Annual Report) uses a definition of leak which conflates "leak" and "hazardous leak." Pursuant to Associations concerns expressed elsewhere in these comments, the instructions should be revised to distinguish between leaks and hazardous leaks.

(d) Reporting of leaks discovered by the public

Part C1 of the Gas Distribution Annual Report requires operators to report the "number of leaks initially discovered by the public", which the report instructions states "includes any leak initially discovered by notification from the public, including reports of gas odor reported under an operator's procedures in §§ 192.605(b)(11) and 192.615(a)(3)."

This definition is likely to introduce confusion, as customer reports of gas odor frequently are determined to involve leakage from piping not jurisdictional to the operator (e.g., customer-owned piping), as well as odors not related to natural gas. These scenarios should not be counted as "leaks" in the Gas Distribution Annual

---

[247] PRIA, at 51.
[248] OMB Control No. 2137-0522, concluded on March 30, 2023 (https://www.reginfo.gov/public/do/PRAViewICR?ref_nbr=202211-2137-001) .
[249] The instructions had provided that "a non-hazardous release that can be eliminated by lubrication, adjustment or tightening is not a leak." Instructions for Form PHMSA F-7100.2-1 at 14.
[250] *Id.*

Report or otherwise. Only natural gas leaks determined to have occurred on piping jurisdictional to the operator should be considered for reporting to PHMSA.

(e) Reporting of "Leaks Discovered"

The proposed Parts C3, C4, and C5 of the Gas Distribution Annual Report (and similarly, Parts M4, M5, and M6 of the Gas Transmission & Gathering Annual Report and Part C1 of the LNG Annual Report) requires operators to document "Leaks Discovered" (e.g., by Corrosion, By Location, and By Cause), distinct from "Leaks Repaired" in Parts C6, M7, and M8 respectively. However, leak cause is unlikely to be determined until the repair event (and maybe not even then, if the leak is eliminated through replacement or retirement), particularly for below-grade leaks. Furthermore, some leaks that were presumed to be a single leak at the time of discovery are found to be a cluster of multiple leaks upon repair. Consequently, the "Leaks Discovered" and "Leaks Repaired" data will not be congruent.

Parts C3, C4, and C5 of the Gas Distribution Annual Report, Parts M4, M5, and M6 of the Gas Transmission & Gathering Annual Report, and Part C1 of the LNG Annual Report should accordingly be struck.

(f) Estimating Emissions (i.e., Part F of Gas Distribution Annual Report, Part U of Gas Transmission & Gathering Annual Report, Part E of LNG Annual Report)

PHMSA states that they "would require that, in developing aggregate emissions estimates, operators would employ direct measurement and/or top-down methodologies along the lines of those discussed above." The ability of operators to estimate aggregate total emissions for gas distribution and transmission and gathering pipeline systems is wildly variable among the Associations' members, and still relatively immature. The vast majority of operators are not positioned to deploy or support comprehensive and advanced top-down methodologies for estimating emissions. Likewise, the training and technology necessary to perform direct measurement of individual leaks is almost unheard of among the operations personnel normally responsible for surveying, investigating, pinpointing, and eliminating leaks. Indeed, most of the commercially-available leak detection technologies described in this NPRM, and the sensitivity requirements proposed therein, are wholly unsuitable for determining emissions in the aggregate or at an individual leak level.

Therefore, any recognized emissions methodology that is available to an operator must be an option for estimating emissions, both in the aggregate and for individual leaks. This includes, but is not limited to, use of material-based emissions factors, evaluation based on leak bubbles, and/or other engineering analysis (based on estimated leak opening, operating pressure, etc.).

Moreover, as discussed above, EPA recently issued a Supplemental Notice of Proposed Rulemaking that would significantly revise Subpart W of the Greenhouse Gas Reporting Program (GHGRP), including allowing for operators subject to the reporting requirements of Subpart W to voluntary use a direct measurement options to calculate emissions data. For the first time, EPA's proposed revisions to Subpart W would allow reporters to voluntarily quantify emissions from equipment leak components by performing direct measurement of equipment leaks—using methods such as calibrated bagging or a high-volume sampler—and calculating emissions using those measurement results as an alternative to using the default leaker emission factors. EPA's proposal to allow the direct measurement of emissions to inform company specific emissions factors is a significant positive development. However, given that most natural gas operators regulated by PHMSA are required to report under Subpart W, it is imperative that PHMSA align any requirement, or option, for direct measurement with EPA's proposed revisions to Subpart W. Failure to do so will likely result in confusion, ambiguity, and the imposition of an unnecessary administrative burden on regulated entities.

(g) PHMSA should revise the deadline for operators to file an annual report from March to June for all future years.

The current deadlines for the Gas Distribution (DOT Form PHMSA F 7100.1-1, Gas Transmission (DOT Form PHMSA F 7100.2–1), LNG Facilities (DOT Form PHMSA F 7100.3-1), and UNGS Facilities (DOT Form PHMSA F 7100.4-1) annual reports is March 15th. Given the changes proposed in this rulemaking and the extensive modifications made to the reporting obligation over the last two years,[251]the Associations recommend that PHMSA move this reporting deadline to June 15th. The agency has provided additional time for annual reports in the past. In 2005, PHMSA's predecessor, the Research and Special Programs Administration, provided hazardous liquid operators until June 15th to file annual reports recognizing that the industry would need additional time to gather the requested information.[252] Hazardous liquid operators continue to have until June 15th to file annual reports each year.[253] A June deadline for natural gas operators will ease the reporting burdens and provide consistent deadlines for both natural gas and hazardous liquid operators. A June deadline should not impact PHMSA's ability to complete inspection planning for the next calendar year.

[251] The length of DOT Form PHMSA F 7100.2–1 has increased from two pages prior to calendar year 2010 to over 20 pages.
[252] Pipeline Safety: Hazardous Liquid Pipeline Operator Annual Reports, 69 Fed. Reg. 537, 539 (Jan. 6, 2004).
[253] 49 C.F.R. § 195.49.

3) Notifications

(a) PHMSA should eliminate the reference to Section 192.703(d)(4) in its proposed modifications to Section 192.18(c).

PHMSA proposes to amend the Section 192.18 notification provision to include a reference to § 192.703(d)(4).[254] However, there is no § 192.703(d)(4) in either the current pipeline safety regulations or proposed in the NPRM. PHMSA should correct this error in the regulatory text.

(b) The agency should limit its use of Section 192.18(c) in the NPRM.

The Associations are concerned that where the costs have not been evaluated in the PRIA, PHMSA may be using the no-objection process to fill the gap. PHMSA must prepare a proper risk assessment and make a reasoned determination to prescribe new requirements. The agency cannot use the no-objection process to address deficiencies in its PRIA.[255]

The Associations provide the following changes to the regulatory text in Parts 191,192, and the reporting forms/instructions for PHMSA's consideration:

§ 191.11 Distribution system: Annual report.

(a) General. Except as provided in paragraph (b) of this section, each operator of a distribution pipeline system must submit an annual report for that system on DOT Form PHMSA F 7100.1-1. This report must be submitted each year, not later than June 15 ~~March 15~~, for the preceding calendar year.

(b) Not required. The annual report requirement in this section does not apply to a master meter system, a petroleum gas system that serves fewer than 100 customers from a single source, or an individual service line directly connected to a production pipeline or a gathering line other than a regulated gathering line as determined in § 192.8.

§ 191.17 Transmission systems, gathering systems, liquefied natural gas facilities, and underground natural gas storage facilities: Annual report.

(a) ***Pipeline systems*** —

(1) ***Transmission, offshore gathering, or regulated onshore gathering.*** Each operator of a transmission, offshore gathering, or regulated onshore gathering pipeline system must submit an annual report for that system on DOT Form PHMSA F 7100.2–1. This report must be

[254] 88 Fed. Reg. at 31,973.
[255] *GPA Midstream Ass'n v. United States Dep't of Transportation*, 67 F.4th 1188, 1199 (D.C. Cir. 2023).

submitted each year, not later than June 15 ~~March 15~~, for the preceding calendar year.

(2) ***Type R gathering.*** Beginning with an initial annual report submitted in March 2023 for the 2022 calendar year, each operator of a reporting-regulated gas gathering pipeline system must submit an annual report for that system on DOT Form PHMSA F 7100.2–3. This report must be submitted each year, not later than June 15 ~~March 15~~, for the preceding calendar year.

(b) ***LNG.*** Each operator of a liquefied natural gas facility must submit an annual report for that system on DOT Form PHMSA 7100.3–1 This report must be submitted each year, not later than June 15 ~~March 15~~, for the preceding calendar year, except that for the 2010 reporting year the report must be submitted by June 15, 2011.

(c) ***Underground natural gas storage facility.*** Each operator of a UNGSF must submit an annual report through DOT Form PHMSA 7100.4–1. This report must be submitted each year, no later than June 15 ~~March 15~~, for the preceding calendar year.

§ 191.19 Large-volume gas release report.

Each operator of a gas pipeline facility must report a large-volume gas release on DOT Form PHMSA–F7100.5. Each report must be submitted within 30 days after detection of a large-volume gas release. A large-volume gas release report is not required if an incident report has already been submitted under this part for the same event, or a report for the same event has already been submitted to the U.S. Environmental Protection Agency acting pursuant to the authority provided in 42 U.S.C. 7401 et seq., a state, or local agency acting pursuant to a delegation of the authority provided in 42 U.S.C. 7401 et seq. by the U.S. Environmental Protection Agency ~~and the release volume identified in the incident report is within 10 percent of the total release volume on cessation of the release~~.

§ 192.18 How to notify PHMSA.

* * * * *

(c) Unless otherwise specified, if an operator submits, pursuant to § 192.8, 192.9, 192.13, 192.179, 192.319, 192.461, 192.506(b), 192.607(e)(4), 192.607(e)(5), 192.619, 192.624(c)(2)(iii), 192.624(c)(6),192.632(b)(3), 192.634, 192.636, ~~192.703(d)(4),~~ 192.706(a)(2), 192.710(c)(7), 192.712(d)(3)(iv), 192.712(e)(2)(i)(E), 192.714, 192.745, 192.760(h), 192.763(c), 192.917, 192.921(a)(7), 192.927, 192.933, or 192.937(c)(7) a notification for use of a different integrity assessment method, analytical method, compliance period, sampling approach, pipeline material, or technique (*e.g.,* ‘‘other technology’’ or ‘‘alternative equivalent technology’’) than otherwise prescribed in those sections, that notification must be submitted to PHMSA for review at least 90 days in advance of using the other method, approach, compliance timeline, or technique. An operator may proceed to use the other method, approach, compliance timeline, or technique 91 days after submitting the notification unless it receives a letter from PHMSA informing the operator that PHMSA objects to the proposal or that PHMSA requires additional time and/or more information to conduct its review.

Annual Reports: PART C of the Gas Distribution Annual Report (and PART M of the Gas Transmission & Gathering Annual Report)

PART C/M – TOTAL LEAKS AND HAZARDOUS LEAKS ELIMINATED/ REPAIRED DURING YEAR

A "leak" is defined as any uncontrolled release of gas from a pipeline that is designed to transport, deliver, or store gas. ~~a "leak or hazardous leak" as defined in 49 CFR 192.3, as any release of gas from a pipeline that is uncontrolled at the time of discovery and is an existing, probable, or future hazard to persons, property, or the environment, or any uncontrolled release of gas from a pipeline that is or can be discovered using equipment, sight, sound, smell, or touch~~

C1 General Leak Information

The number of leaks initially discovered by the public includes any leak on the operator's pipeline or pipeline facilities initially discovered by notification from the public. ~~including reports of gas odor reported under an operator's procedures in §§ 192.605(b)(11) and 192.615(a)(3)~~.

J. Gas Gathering Pipelines—§ 192.9

The Pipeline Safety Act requires PHMSA to conduct a risk assessment as part of the rulemaking process, and that risk assessment must identify the regulatory and non-regulatory options considered, explain why the options identified were either selected or rejected, identify the associated costs and benefits, and describe the technical data or information relied upon in developing the proposed standard and risk assessment. As the D.C. Circuit recently explained in *GPA Midstream Assn v. United States Dep't of Transportation*, failing to comply with the Pipeline Safety Act's risk assessment requirements is a "serious error" that deprives the public and the Gas Pipeline Advisory Committee (GPAC) of the opportunity to participate in the rulemaking process.[256]

PHMSA committed that serious error in developing the proposed LDAR regulations for onshore gas gathering lines in this proceeding. In conducting the risk assessment for Type C gas gathering lines—which only became jurisdictional last year and are not even subject to the rulemaking mandate in Section 113—PHMSA failed to consider any non-regulatory options, erroneously limited its consideration of the available regulatory options, failed to reasonably identify the costs and benefits, and relied on inadequate technical

[256] *GPA Midstream Ass'n v. United States Dep't of Transp.*, 67 F.4th 1188, 1197 (D.C. Cir. 2023).

data and information. The Agency made similar mistakes in conducting the risk assessment for Type A and Type B gathering lines, *e.g.*, PHMSA relied on flawed cost assumptions, ignored critical economic differences between the gathering and transmission sectors, and failed to quantify any of the expected safety benefits, even though those benefits predominate in evaluating the proposals that would require the detection, grading, and repair of small leaks.

The defects in the Proposed Rule go beyond the Agency's failure to comply with the risk assessment requirements in the Pipeline Safety Act. The proposal to require gathering line operators to participate in the National Pipeline Mapping System (NPMS) is also unlawful.

The Associations believe the proposal to clarify that operators of Type B and C gathering lines must develop and implement a manual of written procedures for conducting operations, maintenance, and emergency response activities is reasonable in principle, so long as the final rule aligns with the risk assessment and current regulatory obligations.

Despite these limited areas of agreement, the Agency has no choice but to return to the drawing board in developing the proposed LDAR requirements for onshore gas gathering lines. PHMSA's failure to comply with the risk assessment requirements and the significant substantive flaws in the Proposed Rule cannot be cured without further deliberation within the Agency, followed by additional public notice and the opportunity for comment. Accordingly, the Associations request that PHMSA defer any further consideration of the proposed LDAR requirements for onshore gas gathering lines until a subsequent rulemaking proceeding.

K. Other Definitions—§ 192.3

1. <u>Confined Space or Enclosure</u>

PHMSA introduces a new definition of "confined space" in the NPRM. However, this definition is different from the Occupational Safety and Health Administration's (OSHA) definition of the same term.

OSHA defines "confined space" as:

> a space that: (1) is large enough and so configured than an employee can bodily enter it; (2) has limited or restricted means for entry and exit; (3) is not designed for continuous employee occupancy.

PHMSA acknowledges that its definition differs from the OSHA definition and references the GPTC Guide in support. However, the GPTC Guide is not regulation. While the GPTC Guide uses the phrase, "in which gas could accumulate," and the PHMSA proposed definition uses the phrase, "in which gas could accumulate or migrate," the OSHA definition has the same intent. Having to contend with two different regulatory definitions for the same term is confusing and unnecessary. Since most operators use the OSHA definition in their procedures, the Associations recommend that PHMSA either adopt the OSHA definition or use a different term. Using the same term but defining it differently will create unnecessary confusion and inconsistencies in operator procedures. Being in a permit-required confined space requires workers to monitor oxygen levels and the presence of CO, hydrogen sulfides, or other contaminants.

The Associations recommend PHMSA utilize the term *Enclosure* instead of *Confined space* to eliminate confusion. The words "confined space" should be replaced by "enclosure" in the leak grading criteria included in 192.760.

> ~~Confined space~~ *Enclosure* means any subsurface structure, other than a building, of sufficient size to accommodate a person, and in which gas could accumulate or migrate. These include vaults, certain tunnels, catch basins, and manholes.

2. Gas-associated substructure

The Associations believe as proposed, the definition is too vague. PHMSA should consider providing clarification on the types of substructures intended to be included in the definition, such as: valve box, meter boxes, Cathodic Protection (CP test boxes), etc. The Association provide the following edits intended to provide clarity:

> *Gas-associated substructure* means a substructure that is part of an operator's pipeline delivery infrastructure, but that is not ~~itself~~ designed to contain or transport gas.

3. Leak or hazardous leak

PHMSA is reminded that the Associations believe it is imperative that PHMSA separately define *Leak* and *Hazardous leak* in 192.3 and strongly recommends the Agency remove its proposed definition for *Leak and Hazardous leak* from the Final Rule.

A more thorough discussion of these definitions can be found on pages 55-57 of these comments.

4. Lower Explosive Limit (LEL)

As stated by PHMSA in the NPRM, "the LEL of natural gas is 5% gas by volume."[257] The Associations support the approach of treating the lower explosive limit (LEL) as an operator-defined constant, and are therefore concerned that the qualifier "at ambient

[257] 88 Fed. Reg. at 31,940.

pressure and temperature" – while not technically inaccurate – would suggest that operators are required to determine LEL for every atmospheric condition they face. Even then, ambient pressure and temperature are ever-changing. The qualifiers particular to atmospheric conditions should be struck from the definition of LEL.

> *Lower explosive Limit (LEL)* means the minimum concentration of gas or vapor in air below which propagation of a flame does not occur in the presence of an ignition source ~~at ambient pressure and temperature~~.

5. *Definitions Supported by the Associations*

The Associations support the proposed definitions listed below. However, the Associations note that PHMSA's proposed definitions for *Substructure* and *Tunnel* may need to be further defined. For example, depending on the diameter of a pipeline, some individuals may be able to pass through, but this does not make a pipeline a tunnel.

- *Substructure* means any subsurface structure that is not large enough for a person to enter and in which gas could accumulate or migrate. Substructures include, but are not limited to, telephone and electrical ducts, and conduit, gas and water valve boxes, and meter boxes.
- *Tunnel* is a subsurface passageway large enough for a person to enter and in which gas could accumulate or migrate.
- *Wall-to-Wall paved area* means an area where the ground surface between the curb of a paved street and the front wall of a building is continuously paved, excluding intermittent landscaping, such as tree plots.

L. *Leak Detection and Repair Final Rule effective date*

PHMSA should provide a three-year effective date for the Final Rule. The six-month timeframe proposed in the NPRM is not realistic or achievable. In comparison, Congress provided operators with one year to include the new Section 114 requirements in their operation and maintenance procedures. The proposed modifications in the NPRM reflect a more impactful set of changes. Operators will need to create new compliance programs, change data collection and work management systems, hire and train contractors and new company personnel, modify equipment, and revise procedures. Some specific concerns with the proposed effective date include:

- Operators will need to review and revise as necessary leak investigation, leak survey, leak evaluation, and leak repair processes to comply with the new rule. Work management systems and field devices will need to be reconfigured, developed, or procured to accommodate the new prescriptive criteria requirements. Programming, scheduling, routing, and data collection systems will all need to be modified to support the execution of the work under the new processes.

- Wholesale changes will need to be made to an operator's training modules involving leak detection, leak investigation, scheduled leak survey, leak repair, and reporting. Subsequently, OQ programs and plans will need to be revised. It will take operators months to develop the response to the new regulations; then time is needed to develop new training modules, train their employees, and perform the necessary qualification tests. Qualification for leak survey involves demonstrating knowledge, skills, and abilities in the field, which takes coordination and time.

- Operators will also need to ensure they have appropriate staffing to perform the new or updated requirements. Revising or renegotiating existing contracts will need to occur with the operators' contractors who perform leak surveys and patrols. Operators may need to issue Requests For Proposals to solicit additional leak survey contractors or hire new people to be able to perform this work internally. An ALDP will trigger changes to leak survey requirements for contractors working for operators. The number of qualified personnel is scarce, which will only be worsened by the entire industry relying on the small resource pool simultaneously. All these individuals will need to go through skilling and Operator Qualification in order to become safe, competent and confident.

- For some distribution operators, there will be significant efforts dedicated towards reevaluating and re-managing active known leaks in potentially assigning new dates for their repair or resurvey. This is an activity that cannot be overlooked in the amount of time needed to transition to new rule requirements.

- In addition to leak survey and grading activities, all the proposed requirements related to pressure relief valve operations and maintenance will require modifications to operators O&M plans, OQ plans and training programs.

- Coated steel and plastic distribution mains are currently leak surveyed on a 5-year cycle. PHMSA proposes to reduce the leak survey cycle to 3-years, which would result in many operators being out-of-compliance with the new regulations if the effective date is less than 2-years after the effective date of this rule.

- If finalized as proposed, the majority of the advanced technology providers will not be able to meet the requirements and the increased demand. PHMSA should provide additional time for these providers to ramp up and for operators to acquire the necessary equipment.

While it may be possible to implement certain elements of the final rule sooner, most of the agency's proposals warrant a longer timeframe. The Associations specifically seek a three-year effective date for consistency with EPA's OOOOc rulemaking and to assist operators in addressing the proposed compressor station exception in § 192.703(d)(1)-(3). PHMSA has stated in the NPRM that its section 192.703 exception would not apply until the EPA rule is finalized. PHMSA failed to consider that it could take three or more years before compressor stations would be regulated under the State or Federal plans created to implement these EPA standards. Under EPA's proposed 40 CFR part 60, subpart OOOOc requirements, a State or Federal plan that creates the methane emission monitoring and repair requirements for existing compressor stations across the United States may not apply until three years after EPA issues a final rule promulgating the 40 CFR part 60, subpart OOOOc emission guidelines. A three-year effective date for the PHMSA rule would allow operators with these specific facilities to focus solely on the EPA requirements rather than first setting up a program in compliance with PHMSA regulations and then switching at a later date to an EPA program.

The Associations anticipate that a reasonable effective date will also greatly reduce the number of requests PHMSA may receive from operators to deviate from the timeframes prescribed for Grade 2 and Grade 3 leak repairs. Finally, PHMSA should take into account the competing effective dates and obligations of several PHMSA and EPA rules with similar timeframes.

The Agency's position that the six-month effective date is reasonable because industry has "the time since the issuance of [the] NPRM" is not supported by law. PHMSA cannot expect operators to expend resources on the basis of a proposal. The purpose of an effective date is to allow affected parties to prepare and take action in response to the final rule. Federal courts have determined that the "required publication" of substantive rules as directed in the Administrative Procedure Act is a reference to the final rule and is not satisfied by the publication of a notice of proposed rulemaking. Operators cannot begin implementation efforts until they know the exact requirements in the Final Rule. There were key differences between the NPRMs and the Final Rules issued by PHMSA in recent years. If industry had committed funds on the basis of some of those proposals, it would have had to redo certain efforts.

The Associations also recommend that PHMSA align the effective date of the final rule with the calendar year, January 1, versus time after the final rule publication. Leak surveys are not simple week-long, month-long or seasonal initiatives. They are complex year-long endeavors that involve significant planning. Modifying leak survey cycles should not be changed in the middle of the year. This would require operators to shift their program in the middle of a cycle of a recurring year long process. Changing survey equipment, leak survey frequencies, how patrols and surveys are performed, and IT systems, and having to train and qualify all the new personnel on these new requirements in the middle of an active leak survey year will cause unnecessary confusion. The effective date for the final rule should therefore occur at the start of a calendar year in order to ease transition and enable operators to submit accurate data to PHMSA on their annual reports.

The Associations strongly recommend that PHMSA provide an effective date not less than three years from the date the final rule is published, to begin on the first day of the calendar.

M. PHMSA Solicitation of Comments

In the NPRM, PHMSA solicits comments on several issues. As discussed previously, PHMSA cannot propose topics generally and meet its obligations under the APA. Stakeholders must be given an opportunity to comment. The Associations have offered to provide the following responses to some of those questions included in the preamble:

1. ***Leak Grading & Repair Questions***

1. Other potential criteria for identifying grade 1 leaks subject to immediate repair, including the utility of adopting a quantified emissions rate criteria for grade 1 leaks or other characteristics indicative of a *grave environmental hazard*

    The Associations do not recognize pipeline leakage, particularly from an individual leak, as a "grave environmental hazard". Detailed comments pursuant to Grade 1 leak criteria have been provided on pages 60-61.

2. Alternative grade 2 emissions rate criterion thresholds and calculation methodologies—particularly considering the extent to which emissions from below ground leaks could be incorporated

    The associations have provided detailed comments on the various criteria it supports to represent a Grade 2 leak on pages 61-64. We do not believe it is appropriate for PHMSA to govern the methodologies that operators use to calculate leakage rate or the leak extent under the Grade 2 criterion.

3. Proposed criteria for identifying grade 2 leaks that constitute a significant hazard to the environment, including the practicability of using a specified emissions rate criterion (and whether 10 CFH is the appropriate emissions rate for grade 2 leaks).

    The Associations do not accept that the non-zero environmental harm posed by a natural gas leak constitutes a “significant hazard” to the environment. The revised criteria for Grade 2 leaks proposed by the Associations acknowledges the environmental significance of certain leaks based on estimated leakage rate, estimated “leak extent” (land area affected by gas migration), or alternative criteria as defined by the operator. believe that not all leaks represent a significant, imminent hazard to the environment.

2. ***Advanced Leak Detection Program (ALDP) Questions***

1. Introducing requirements for continuous monitoring systems, via stationary gas detection systems, pressure monitoring, or other means (including requirements for the use of specific methods or technologies), on other types of pipeline facilities

(including whether continuous monitoring would be most appropriate at any particular facilities or locations, or in other particular conditions) within a final rule

As prescribed in 192.935(a)(1)(vi), gas transmission pipeline operators are already required to consider (among several other additional preventive and mitigative measures) the use of leak detection systems (e.g., Computational Pipeline Monitoring (CPM)) within high consequence areas (HCA). This consideration is prudent for pipelines operating in HCAs, but no justification has been made for applying this added requirement to other pipelines.

2. Requiring continuous monitoring systems in recognition of less sensitive leak detection equipment authorized for use pursuant to proposed § 192.763(c), challenging survey conditions, facilities known to leak based on their material, design, or past operating and maintenance history, or any other pipeline facilities

PHMSA itself has authority to disallow less sensitive leak detection equipment that operators may propose (as an alternative performance standard) under § 192.763(c). It is disingenuous to propose a means of having an alternative performance standard approved for use, and then use that proposed alternative as a pretext for imposing more stringent leak detection requirements.

Other risks such as challenging survey conditions and leak-prone facilities are already covered in their entirety by this rulemaking and related DIMP provisions.

3. Whether and how an alternative ALDP performance standard—such as a more demanding volumetric standard, or a flowrate-based standard—should be adopted in the final rule

As discussed on pages 88-93, there are many instruments and technologies used for leak detection, and all do not report in the same values. There must be flexibility in the criteria used to establish instrument sensitivity due to the specific application and function served by the instrument. The Associations would oppose the imposition of a single volumetric or flow rate-based standard since not all instruments provide estimated leak rates.

3. ***Leakage Survey and Patrol Frequencies and Methodologies—Distribution***

1. Potential to define the boundaries of business districts.

For decades operators have been meeting the regulatory requirement to increase leak surveys in business districts. Absent quantifiable data justifying a need for PHMSA to intervene in that process, the Associations contend that each operator knows its environmental conditions and geography best and should determine business district definition based on GPTC guidance and corporate business plans (DIMP, O&M).

2. Value of either explicitly listing (either within part 192 or within periodically-issued implementing guidance) historic plastics known to leak, or deleting the scope qualification “historic” from the proposed regulatory text, for the purposes of the proposed annual survey requirement or for replacement under Section 114 of the PIPES Act of 2020.

   Historic plastics are not known to leak in every service territory. Every operator’s service territories and geographies are different and it is important to allow operators to use a risk-based approach based on individual conditions and location, consistent with the principles of DIMP and TIMP.

3. Requirement to perform assessments prior to extreme weather events in order for operators to prepare for and prevent resulting leaks.

   Predicting the precise impact and location of individual extreme weather events on gas pipeline facilities is impractical. An assessment prior to a predicted weather event would not provide reliable insight to an operator for preparation or for leak prevention.

4. Value of more or less frequent leakage surveys of plastic pipe systems, as well as potential means to identify plastic pipe known to leak (e.g., via a surveillance or sampling program.

   Proneness of certain vintage plastics to brittleness and cracking is well understood, and has been the topic of several PHMSA Advisory Bulletins and NTSB recommendations. There is a variety of research indicating recent vintage plastic pipe is less leak prone than some older vintage plastics. PHMSA released several advisory bulletins 1999 (2) 2002 (1) 2007(1) (DRISCO 8000 2012 and 2021) based on NTSB recommendations, indicating earlier vintages (1960-1980s) may be more vulnerable to cracking. Also, EPA Table W-7 to Subpart W of Part 98 Emission factors indicate low emissions factors for plastic pipes.

4. ***Investigation of Failures Question***

1. Broad application of proposed definition of "failure" to all of 49 CFR 192 by defining in § 192.3 (as opposed to § 192.617)

In the NPRM, PHMSA invites comment on whether it should include its proposed new definition of 'failure' in Section 192.3 and therefore apply this definition throughout Part 192.[258] PHMSA specifically states that it would consider making this change "in a final rule in this proceeding."[259] The agency has not evaluated the cost and benefits of making such a change and would need to do so first to satisfy its statutory obligations. The D.C. Circuit has held that "PHMSA must submit for peer review and make available for public comment a risk assessment identifying 'the costs and benefits associated with the proposed standard.'"[260] PHMSA must evaluate the impacts adding a new definition of failure throughout Part 192 prior to finalizing such an impactful change. The Associations would strongly oppose this, since it would have ramifications that go beyond the scope of the requirements noted in this particular regulation.

5. ***Mitigating Vented and Other Emissions From Gas Pipeline Facilities Questions***

1. Appropriateness of specifying a minimum pressure or pressure reduction in the vented segment for pressure reduction methods, and any other mitigation measures operators should consider

A universal minimum pressure requirement would be challenging to set due to wide variety of operational conditions that could be experienced. Depending on how low the minimum pressure requirement is, it could be untimely, not cost-effective, or impracticable to achieve a minimum pressure for large blowdowns or for sections operating at higher pressures. Drafting or transferring gas to an adjacent line can be limited by regulation or downstream consumption, the latter of which is variable and largely uncontrollable. The performance of cross compression devices significantly worsens at lower pressures and can increase the time of abatement operations by orders of magnitude. Because of these reasons, the Associations suggest not including a minimum pressure or pressure reduction.

---

[258] 88 Fed. Reg. at 31,952.
[259] *Id.*
[260] *GPA Midstream Ass'n v. United States Dep't of Transportation*, 67 F.4th 1188, 1197 (D.C. Cir. 2023)(citing 49 U.S.C. § 60102(b)(3)(B)).

2. Requirement that any (or all) of the release volume mitigation approaches proposed in §§ 192.770(a)(1) through (5) and 193.2523(a)(1) through (3) reduces the volume of released gas by at least 50% compared with taking no action

   If the 50% reduction framework is to be maintained, it should be applied to planned venting activity that would exceed 1 MMCF without mitigative action. Resources are better allocated on targeting large blowdowns to reduce overall emissions. Furthermore, a per-venting comparison of achieved percent reduction (in emissions-to-potential-emissions) is not valuable or useful, as the amount of emissions reduced may vary by orders of magnitude.

3. Appropriateness of requiring methods for mitigating transmission pipeline and LNG facility blowdown emissions proposed in NPRM for use on gas distribution or Types B and C gathering pipelines

   Much smaller gas volumes are vented in distribution due to lower pressures and small pipe diameters. Any or all amount abated on distribution blowdowns would be negligible compared to potential emissions on transmission blowdowns. The Associations believe allocating resources to distribution blowdown abatement should not be considered until significant transmissions blowdown abatement has been achieved.

4. Appropriateness of restricting the use of flaring to instances where other mitigation measures are impracticable

   Clarification is needed as to what criteria needs to be met to prove other abatement measure are impractical. Furthermore, the Associations disagree with the idea that flaring methane should be the method of last resort. Flaring can and has been used in conjunction with other abatement methods to clear pipeline in a timely manner.

6. *Reporting and National Pipeline Mapping System Questions*

1. Utility of requiring operators to report more granular leak data.

   As acknowledged by PHMSA in the NPRM, there were 510,224 gas distribution leak repairs reported in calendar year 2020 alone. Importantly, this historical leak repair volume has not included leaks eliminated by lubrication, adjustment or tightening, which PHMSA has explicitly instructed operators not to report. Reporting granular data such as location, emissions, and repair timing for more than half a million individual leaks per year is wholly impractical given the skills, resources, and commercially available technology currently deployed by operators in pinpointing and repairing leaks, as well as a lack of clarity and maturity around methodologies for determining emissions from an individual leak.

2. Alternative reporting thresholds for either large volume gas releases or incidents, including thresholds below 1 MMCF.

Current PHMSA incident reporting regulations already prescribe a de facto threshold for environmentally significant unintentional releases of 3 MMCF or more. A consistent threshold is also appropriate for large-volume intentional releases, which in any case are already being prevented and mitigated through (1) the initiative of operators (e.g., the 70% decline in gas distribution methane emissions between 1990 and 2019 cited by PHMSA in the NPRM), (2) the self-executing provisions of PIPES Act 2020 Section 114, and (3) proposed rule § 192.770 for minimizing blowdown emissions. Consequently, a reporting threshold of 3 MMCF is appropriate for both incident reporting (unintentional) and large-volume gas release (intentional) scenarios.

Additionally, PHMSA should also ensure that any alternative threshold is aligned and consistent with EPA's proposed revisions to Subpart W of the GHGRP. In its proposed rule, EPA is proposing to add "other large release events" (*i.e.*, abnormal emission events or "super-emitters," such as well blowouts, well releases, releases from equipment rupture, fire, or explosions) as a new emissions source subject to reporting under Subpart W. All natural gas industry sectors would be subject to this requirement. This proposal is similar, but not identical, to the "other large release events" requirement included in EPA's 2022 proposed revisions to Subpart W—the primary difference being that EPA is now proposing to include an instantaneous CH4 emission rate threshold of 100 kg/hour for Subpart W, in addition to the 2022 Proposal's 250 mtCO2e per-event threshold for determining whether an emissions event must be reported. Under EPA's proposal, a release of at least 250 mtCO2e per event *or* a CH4 emission rate of 100 kg/hour at any point would qualify as an "other large release event." EPA is proposing that "other large release events" include planned releases, such as those associated with maintenance activities, for which there are not already emission calculation procedures in Subpart W, or releases from equipment for which the existing Subpart W calculation methodologies would significantly underestimate the episodic nature of those emissions.

EPA's proposed rule would also include new calculation requirements that rely on measurement data (if available), or a combination of engineering estimates, process knowledge, and best available data, to estimate the amount and composition of released gas from "other large release events."

EPA is proposing that direct measurement of every release is not required; however, if an owner or operator has "credible information" that a release meets or exceeds (or may be reasonably anticipated to meet or exceed) the threshold emissions, then the release must be quantified and, if it is confirmed to exceed one of the thresholds, reported as an "other large release event."[261] *See* 88 Fed. Reg. at 50,296–301. Again, given that many natural gas pipeline operators subject to PHMSA's proposed rule are also required to report under Subpart W, it is essential that PHMSA and EPA coordinate and align their reporting requirements for large volume releases in order to ensure consistency and to prevent confusion in the reporting process.

3. Proposal to revise § 192.605 to address operator procedures for responding to third-party reports of gas releases, or leverage EPA's super-emitter response program for third party leak reporting

Inserting procedural requirements for operator response to reports of potential leaks and gas releases from "watchdog groups" and other similar third-party entities is likely to create distractions from operators' primary objective of ensuring public safety. Third parties do not have the system or operational knowledge to reliably identify gas releases from operators' jurisdictional facilities that are otherwise unknown to the operator, and there is considerable opportunity for operational disruption by bad actors. Proceduralizing third-party identification of purported gas releases is itself an indictment of the considerable regulatory requirements (current and proposed) for identifying, preventing, and mitigating intentional and unintentional gas releases by operators.

7. *Underground Natural Gas Storage*

1. Application of the subpart N operator qualification requirements to UNGSFs.

The NPRM solicits comment on whether to apply certain subpart N operator qualification requirements to underground natural gas storage facilities (UNGSFs).[262] Apart from recognizing that PHMSA does not currently apply subpart N to UNGSFs, the NPRM provided no further discussion on the topic, and did not identify any reason for doing so. Without any detail in the NPRM, the Associations cannot substantively respond to the request. However, the Associations note that PHMSA has long understood that UNGSFs are unique facilities that should be treated

[261] *See* 88 Fed. Reg. at 50,296–301.
[262] *Id.* at 31,945.

differently than other regulated pipeline facilities.[263] Sec. 192.12 explicitly exempts UNGSFs from other part 192 requirements, including subpart N. Further, API RPs 1170 and 1171 already include sufficient qualification and training requirements that are tailored to UNGSFs. Adding subpart N requirements may cause issues with existing 1170 and 1171 requirements and the new requirements may be incongruent with UNGSF operations.

2. Introduction of leakage survey frequency and leak detection equipment requirements to UNGSFs.

   The NPRM seeks comment on whether to amend Sec. 192.12 to apply leakage survey frequency and leak detection equipment requirements to UNGSFs.[264] PHMSA did not provide any details as to what these requirements might look like or conduct a cost-benefit analysis to support applying these requirements to UNGSFs. The NPRM and preliminary regulatory impact assessment fail to provide the necessary analysis to support the inclusion of UNGSF leakage survey or leak detection equipment requirements in the final rule.

The Associations' suggested changes to the proposed code requirements are compiled and presented below, in ascending order with respect to code sequence under Parts 191, 192, and 193[265]:

§ 191.11 Distribution system: Annual report.

(a) General. Except as provided in paragraph (b) of this section, each operator of a distribution pipeline system must submit an annual report for that system on DOT Form PHMSA F 7100.1-1. This report must be submitted each year, not later than June 15 ~~March 15~~, for the preceding calendar year.

(b) Not required. The annual report requirement in this section does not apply to a master meter system, a petroleum gas system that serves fewer than 100 customers from a single source, or an individual service line directly connected to a production pipeline or a gathering line other than a regulated gathering line as determined in § 192.8.

---

263 *See* PHMSA UNGSF FAQs, No. 12, which states subpart N does not apply to UNGSFs and operators should use the provisions in API RPs 1170 and 1171 for training and qualifications.
264 88 Fed. Reg. 31,890, 31,926 (May 18,2023).
265 As stated previously, all regulatory text recommended by the Associations in these comments use the following color scheme: blue underline for PHMSA's proposed additions supported by the Associations; ~~red strike-through~~ for PHMSA's proposed deletions supported by the Associations; purple underline (or ~~purple strike-through~~) for revisions suggested by the Associations.

§ 191.17 Transmission systems, gathering systems, liquefied natural gas facilities, and underground natural gas storage facilities: Annual report.

(a) ***Pipeline systems*** —

(1) ***Transmission, offshore gathering, or regulated onshore gathering.*** Each operator of a transmission, offshore gathering, or regulated onshore gathering pipeline system must submit an annual report for that system on DOT Form PHMSA F 7100.2–1. This report must be submitted each year, not later than June 15 ~~March 15~~, for the preceding calendar year.

(2) ***Type R gathering.*** Beginning with an initial annual report submitted in March 2023 for the 2022 calendar year, each operator of a reporting-regulated gas gathering pipeline system must submit an annual report for that system on DOT Form PHMSA F 7100.2–3. This report must be submitted each year, not later than June 15 ~~March 15~~, for the preceding calendar year.

(b) ***LNG.*** Each operator of a liquefied natural gas facility must submit an annual report for that system on DOT Form PHMSA 7100.3–1 This report must be submitted each year, not later than June 15 ~~March 15~~, for the preceding calendar year, except that for the 2010 reporting year the report must be submitted by June 15, 2011.

(c) ***Underground natural gas storage facility.*** Each operator of a UNGSF must submit an annual report through DOT Form PHMSA 7100.4–1. This report must be submitted each year, no later than June 15 ~~March 15~~, for the preceding calendar year.

§ 191.19 Large-volume gas release report.

Each operator of a gas pipeline facility must report a large-volume gas release on DOT Form PHMSA–F7100.5. Each report must be submitted within 30 days after detection of a large-volume gas release. A large-volume gas release report is not required if an incident report has already been submitted under this part for the same event, or a report for the same event has already been submitted to the U.S. Environmental Protection Agency acting pursuant to the authority provided in 42 U.S.C. 7401 et seq., a state, or local agency acting pursuant to a delegation of the authority provided in 42 U.S.C. 7401 et seq. by the U.S. Environmental Protection Agency ~~and the release volume identified in the incident report is within 10 percent of the total release volume on cessation of the release~~.

§ 192.3 Definitions

Leak means any uncontrolled release of gas from a pipeline that is designed to transport, deliver, or store gas.

Hazardous leak means a leak that represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous.

~~Confined space~~ *Enclosure* means any subsurface structure, other than a building, of sufficient size to accommodate a person, and in which gas could accumulate or migrate. These include vaults, certain tunnels, catch basins, and manholes.

Gas-associated substructure means a substructure that is part of an operator's pipeline delivery infrastructure, but that is not ~~itself~~ designed to contain or transport gas.

Lower explosive Limit (LEL) means the minimum concentration of gas or vapor in air below which propagation of a flame does not occur in the presence of an ignition source ~~at ambient pressure and temperature~~.

§ 192.18 How to notify PHMSA.

* * * * *

(c) Unless otherwise specified, if an operator submits, pursuant to § 192.8, 192.9, 192.13, 192.179, 192.319, 192.461, 192.506(b), 192.607(e)(4), 192.607(e)(5), 192.619, 192.624(c)(2)(iii), 192.624(c)(6),192.632(b)(3), 192.634, 192.636, ~~192.703(d)(4),~~ 192.706(a)(2), 192.710(c)(7), 192.712(d)(3)(iv), 192.712(e)(2)(i)(E), 192.714, 192.745, 192.760(h), 192.763(c), 192.917, 192.921(a)(7), 192.927, 192.933, or 192.937(c)(7) a notification for use of a different integrity assessment method, analytical method, compliance period, sampling approach, pipeline material, or technique (*e.g.,* ''other technology'' or ''alternative equivalent technology'') than otherwise prescribed in those sections, that notification must be submitted to PHMSA for review at least 90 days in advance of using the other method, approach, compliance timeline, or technique. An operator may proceed to use the other method, approach, compliance timeline, or technique 91 days after submitting the notification unless it receives a letter from PHMSA informing the operator that PHMSA objects to the proposal or that PHMSA requires additional time and/or more information to conduct its review.

§ 192.199 Requirements for design and configuration of pressure relief and limiting devices.

* * * * *

(e) Have discharge stacks, vents, or outlet ports designed to prevent accumulation of water, ice, or snow, located where gas can be discharged into the atmosphere without creating a potential hazard ~~undue hazard~~ to public safety;

* * * * *

(i) All new, ~~replaced~~ or reconfigured, ~~relocated, or otherwise changed~~ pressure relief and limiting devices must be designed and configured, ~~as demonstrated by~~ with documentation, ~~a documented engineering analysis~~, to ~~minimize unnecessary releases of gas by ensuring each of the following:~~ activate when needed, in order to preserve public safety. Additional criteria for operators are as follows:

(1) The set and reset actuation pressure of the pressure relief device and where pressures are taken must limit necessary ~~minimize~~ release volumes. ~~beyond what is necessary to provide adequate overpressure protection;~~

(2) The design (including sizing and material) and configuration of the pressure relief device and its associated piping must be appropriate for its set and reset actuation pressure ~~to minimize pressure choking~~, compatible with the composition of transported gas, and suitable ~~for reliable operation~~ in expected operating and environmental conditions; and

(3) Installation of the pressure relief device must include ~~upstream and downstream~~ isolation valve(s) to facilitate testing and maintenance.

§ 192.503 General requirements.

(b) No person may operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced, until—

(1) It has been tested in accordance with this subpart and § 192.619 to substantiate the maximum allowable operating pressure; and

(2) Each **potentially** hazardous leak has been located and eliminated.

….

§ 192.507 Test requirements for pipelines to operate at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. (689 kPa) gage.

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. (689 kPa) gage must be tested in accordance with the following:

(b) The pipeline operator must use a test procedure that will ensure discovery of all **potentially** hazardous leaks in the segment being tested.

….

§ 192.509 Test requirements for pipelines to operate below 100 p.s.i. (689 kPa) gage.

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated below 100 p.s.i. (689 kPa) gage must be leak tested in accordance with the following:

(b) The test procedure used must ensure discovery of all **potentially** hazardous leaks in the segment being tested

…

§ 192.513 Test requirements for plastic pipelines.

(c) Each segment of a plastic pipeline must be tested in accordance with this section.

(d) The test procedure must insure discovery of all **potentially** hazardous leaks in the segment being tested.

§ 192.553 General requirements.

(b) Pressure increases. Whenever the requirements of this subpart require that an increase in operating pressure be made in increments, the pressure must be increased gradually, at a rate that can be controlled, and in accordance with the following:

(3) At the end of each incremental increase, the pressure must be held constant while the entire segment of pipeline that is affected is checked for leaks.

(4) Each leak detected must be repaired before a further pressure increase is made, **except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous**~~.~~

….

§ 192.557 Uprating: Steel pipelines to a pressure that will produce a hoop stress less than 30 percent of SMYS: plastic, cast iron, and ductile iron pipelines.

(c) Unless the requirements of this section have been met, no person may subject:

(1) A segment of steel pipeline to an operating pressure that will produce a hoop stress less than 30 percent of SMYS and that is above the previously established maximum allowable operating pressure; or

(2) A plastic, cast iron, or ductile iron pipeline segment to an operating pressure that is above the previously established maximum allowable operating pressure.

(d) Before increasing operating pressure above the previously established maximum allowable operating pressure, the operator shall:

(1) Review the design, operating, and maintenance history of the segment of pipeline;

(2) Make a leakage survey (if it has been more than 1 year since the last survey) and repair any leaks that are found, **except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous.**

§ 192.605 Procedural manual for operations, maintenance, and emergencies.

(b) * * *

* * * * *

(13) Eliminating leaks in accordance with leak repair schedules specified in § 192.760 and ~~minimizing~~ reducing releases of gas from pipelines, as well as remediating or replacing pipelines known to leak based on their material, design, or past operating and maintenance history.

§ 192.617 Investigation of failures and incidents

* * * * *

(e) Failure defined. For the purposes of this section, the term failure means ~~when~~ an event in which any portion of a pipeline becomes completely inoperable, is incapable of ~~safely~~ satisfactorily performing its intended function, or has become unreliable or unsafe for continued use.

§ 192.703 General.

* * * * *

(c) ~~Hazardous~~ L~~l~~eaks must be graded and repaired ~~promptly~~ in accordance with the requirements in § 192.760.

(d) Compliance with §§ 192.703(c), 192.705 for patrols, 192.706 for leakage surveys, 192.760(a) through (h) for leak grading and repair, 192.763 for advanced leak detection programs, and 192.769 for qualification of leakage survey personnel, is not required for a compressor station on a gas transmission or gathering pipeline if:

(1) The facility is subject to methane emission monitoring and repair requirements under either:

(i) 40 CFR part 60, subparts OOOOa or OOOOb; or

(ii) an EPA-approved State plan or Federal plan which includes relevant standards at least as stringent as EPA's finalized emissions guidelines in 40 CFR part 60, subpart OOOOc;

(2) The facility is within the first block valve entering or exiting the compressor station covered by the emergency shutdown system as required in § 192.167 for station isolation from the pipeline~~; and~~

~~(3) Repair records are maintained for the life of the facility in accordance with § 192.760(i).~~

§ 192.705 Transmission lines: Patrolling.

* * * * *

(b) Operators must conduct patrols:

(1) At least ~~12~~ 6 times each calendar year at intervals not exceeding ~~45~~ 75 days; or

(2) A risk-based approach considering the size of the line, the operating pressures, the class location, terrain, weather, and other relevant factors, with the following maximum intervals:

Class location of line	**Maximum Interval Between Patrols**
1	4 ½ months, but at least four times each calendar year
2	4 ½ months, but at least four times each calendar year
3	2 ½ months, but at least six times each calendar year
4	2 ½ months, but at least six times each calendar year

* * * * *

§ 192.706 Transmission lines: Leakage surveys.

(a) *General.* Each operator must perform periodic leakage surveys in accordance with this section. Each leakage survey must be conducted according to the advanced leak detection program requirements in § 192.763, except that human or animal senses may be used in lieu of leak detection equipment only in the following circumstances:

(1) An offshore gas transmission pipeline below the waterline or offshore gathering pipeline below the waterline; or

(2) An onshore transmission line outside of an HCA or a gathering pipeline, each either in a Class 1 or Class 2 location, with advance notification to PHMSA in accordance with § 192.18. The notification must include tests or analyses demonstrating that the survey method would meet the ALDP performance standard in § 192.763(b) or (c) (as applicable).

(b) *Frequency of surveys.* Except as provided in paragraphs (c) and (d) of this section, leakage surveys must be performed at the following intervals:

(1) Pipelines outside of HCAs or located on the Alaskan North Slope (ANS) must be surveyed at least once per calendar year, but with an interval between surveys not to exceed 15 months; and

(2) Pipelines in HCAs must be surveyed as follows, unless they are located on the Alaskan North Slope (ANS):

(i) In Class 1, Class 2, and Class 3 locations, at least twice each calendar year, with intervals not exceeding 7 ½ months;

(ii) In Class 4 locations, at least four times each calendar year, with intervals not exceeding 4 ½ months.

(c) *Non-odorized pipelines.* Leakage surveys ~~of a transmission line~~ for pipelines ~~must be conducted at intervals not exceeding 15 months, but at~~

~~least once a calendar year~~ transporting gas in conformity with § 192.625 without an odor or odorant, must perform leakage surveys using leak detection equipment at the following intervals:

(1) In Class 3 locations, at least twice each calendar year, at intervals not exceeding 7 ½ months.

(2) In Class 4 locations, at least four times each calendar year, at intervals not exceeding 4 ½ months.

(d) *Valves, flanges and certain other facilities.* Leakage surveys of all valves, flanges, pipeline tie-ins with valves and flanges, ILI launcher and ILI receiver facilities, and pipelines known to leak based on material (including cast iron, unprotected steel, wrought iron, and historic plastics with known issues), design, or past operating and maintenance history, must be performed at the following intervals:

(1) In Class 1, Class 2, and Class 3 locations, at least twice each calendar year, at intervals not exceeding 7 ½ months.

(2) In Class 4 locations, at least four times each calendar year, at intervals not exceeding 4 ½ months.

§ 192.723 Distribution systems: Leakage surveys.

(a) General. Each operator of a gas distribution pipeline must conduct periodic leakage surveys with leak detection equipment in accordance with this section. All leakage surveys performed pursuant to this section must use leak detection equipment that meets the requirements of § 192.763.

(b) Business districts. Leakage surveys must be conducted at least once each calendar year, at intervals not exceeding 15 months, consisting of atmospheric tests at each gas, electric, telephone, sewer, water, or other system manhole; crack in the pavement and sidewalks; and any other location that provides an opportunity for finding gas leaks.

(c) Non-business districts. Leakage surveys must be conducted at least once every 5 ~~3~~ calendar years, at intervals not exceeding 63 ~~39~~ months, unless a shorter inspection interval is required either by paragraph (d) of this section, the operator's operations and maintenance procedures, or the operator's integrity management plans under part 192, subpart P.

(d) Frequency of regular leakage surveys. Leakage surveys must be conducted at least once every calendar year, at intervals not exceeding 15 months, for~~:~~

~~(1) Cathodically unprotected distribution pipelines subject to § 192.465(e);~~

~~(2) P~~pipelines ~~known to leak based on their material (including cast iron, unprotected steel, wrought iron, and~~ constructed of ~~historic~~ plastics with known issues~~), design,~~ or pipelines known to leak based on past operating and maintenance history~~; and~~

~~(3) Gas distribution pipeline systems protected by a distributed anode system, in the area of deficient readings identified during a cathodic protection survey pursuant to § 195.463 and Appendix D, until the cathodic protection deficiency is remediated.~~

~~(e) Investigating known leaks after environmental changes. An operator must periodically investigate a known Class 2 leak, including conducting a leakage survey for possible gas migration, as soon as practicable when environmental changes such as freezing ground, heavy rain, flooding, or other changes to the environment, as identified in the operator's procedures (DIMP, O&M, etc.), occur that could affect the venting of gas or could cause migration of gas to the outside wall of a building.~~

(e) Extreme Weather Surveys. Leakage surveys must be performed after extreme weather events and land movement with the likelihood to cause damage to the affected pipeline segment. The survey must be initiated within 72 hours after the cessation of the event, defined as either the point in time when the affected area can be safely accessed by the personnel and equipment required to perform the leakage survey or when the facility has been returned to service.

Note: § 192.739 is cited as the proper code section for the proposed requirements captured in § 192.773

§ 192.739 Pressure limiting and regulating stations: Inspection, ~~and~~ testing, maintenance and records.

Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is—

(1) In good mechanical condition;

(2) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

(3) Except as provided in paragraph (b) of this section, set to control or relieve at the correct pressure consistent with the pressure limits of § 192.201(a); and

(4) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

If a malfunction is discovered, operators shall address paragraphs (c), (d) and (e).

(b) For steel pipelines whose MAOP is determined under § 192.619(c), if the MAOP is 60 psi (414 kPa) gage or more, the control or relief pressure limit is as follows:

If the MAOP produces a hoop stress that is:	Then the pressure limit is:
Greater than 72 percent of SMYS	MAOP plus 4 percent.
Unknown as a percentage of SMYS	A pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP.

(c) Each operator must develop, maintain, and follow written operations and maintenance procedures to ~~assess~~ evaluate the proper function of pressure limiting or relief device and to repair or replace each ~~failed~~ pressure limiting or relief device, wherever one is found to have malfunctioned. When a pressure limiting or relief device fails to operate or allows gas to release to the atmosphere at an operating pressure above or below the set actuation pressure range defined for the device in the operator's operations and maintenance procedure, the operator must:

(1) ~~Assess the pilot, springs, seats, pressure gauges, and other~~ Evaluate relief device components to ensure proper functioning, sensing, and set/reset actuation pressures are within actuation pressure tolerances;

(2) ~~Assess~~ Evaluate the inlet and outlet piping for piping that restricts the inlet or outlet gas flow, piping that restricts the sensing pressure, and evaluate for debris~~, and~~ or other restrictions that could impede the operation or restrict the capacity to relieve overpressure conditions;

(3) Repair or replace the device to eliminate the malfunction as follows:

(i) If a pressure relief device activates above its set pressure and above the pressure limits in § 192.201(a) or 192.739(b) as applicable, fails to operate, or otherwise fails to provide overpressure protection, the operator must take immediate ~~and continuous~~ action to address the issue ~~upon discovery.~~ The repair or replacement of the device or pressure sensing equipment should occur as soon as practicable. ~~immediately.~~

(ii) If an operator learns a pressure relief device allows gas to release to the atmosphere at an operating pressure below the set actuation pressure range, the operator must take immediate ~~and continuous~~ action to address the issue with on-site personnel to stop the release until the device is repaired or replaced. Repairs should occur ~~The relief device or pressure sensing equipment must be repaired or replaced~~ as soon as practicable. ~~but within 30 days.~~

(d) Each operator must develop, maintain, document, and follow written operations and maintenance procedures to ensure that a pressure relief device configuration~~, as demonstrated supported by a documented engineering analysis,~~ employs set and reset actuation pressures ensuring limitation ~~minimization~~ of release volumes, while still providing ~~adequate~~ necessary overpressure protection.

(e) Records under this section must be maintained as follows:

~~(1) Records of relief devices malfunctions must be maintained for 5 years after repair or replacement.~~

~~(2) Records pertaining to repair, replacement, or reconfiguration (including any engineering analyses) of a pressure relief device must be maintained for the life of the pipeline.~~

Records of malfunctions, as well as method of repair, replacement, or reconfiguration, shall be maintained for 5 years.

§ 192.760 Leak grading and repair/remediation.

(a) *General.* Each operator must have and follow written procedures for grading and repairing or remediating leaks that meet or exceed the requirements of this section.

(1) These requirements are applicable to leaks found on all portions of a gas pipeline including, but not limited to, line pipe, valves, flanges, meters, regulators, tie-ins, launchers, and receivers.

(2) The leak grading and repair ~~procedure~~ methods must prioritize leak repairs/remediation by the hazard to public safety and ~~the~~ environmental significance ~~environment~~.

(3) Each leak must be investigated and a leak grade established as part of the leak investigation process.~~immediately and continuously until a leak grade determination has been made~~.

(b) *Grade 1 leaks.*

(1) A grade 1 leak ~~is any leak that constitutes an existing or probable hazard to persons or property or a grave hazard to the environment is environmentally significant. A grade 1 leak~~ includes a leak with any of the following characteristics:

(i) A hazardous leak, as defined in § 192.3. ~~ny leak that, in the judgment of operating personnel at the scene is regarded as an existing or probable hazard to public safety or a grave hazard to the environment~~;

(ii) Any amount of escaping gas has ignited;

(iii) Any indication that gas has migrated into a building, under a building, or into a tunnel;

(iv) For an underground leak, ~~A~~any reading of gas at the outside wall of a building, or areas where gas could migrate to an outside wall of a building;

(v) Any reading of 80% or greater of the LEL (60% for LPG systems) in ~~a confined space~~ an enclosure;

(vi) Any reading of 80% or greater of the LEL (60% for LPG systems) in a substructure, (including gas associated substructures) from which any gas could migrate to the outside wall of a building

(vii) ~~Any leak that can be seen, heard, or felt; o~~

~~(viii)~~ Any leak defined as an incident in § 191.3.

(2) An operator must promptly repair a grade 1 leak and eliminate the hazardous conditions by taking immediate and continuous action by operator personnel at the scene. Immediate action means the operator will begin instant efforts to remediate and repair the leak upon detection and to eliminate any hazardous conditions caused by the leak. Continuous means that the operator must maintain on-site remediation efforts until the leak repair has been completed. This may require one or more of, but not limited to, the following actions be taken without delay:

(i) Implementing an emergency plan pursuant to § 192.615;

(ii) Evacuating premises;

(iii) Blocking off an area;

(iv) Rerouting traffic;

(v) Eliminating sources of ignition;

(vi) Venting the area by removing manhole covers, bar holing, installing vent holes, or other means;

(vii) Stopping the flow of gas by closing valves or other means; or

(viii) Notifying emergency responders.

(c) *Grade 2 leaks.*

(1) A grade 2 leak ~~constitutes a probable future hazard to persons or property or a significant hazard to the environment, and~~ includes any leak (other than a grade 1 leak) with any of the following characteristics:

(i) A reading of 40% or greater of the LEL under a sidewalk in a wall-to-wall paved area that does not qualify as a grade 1 leak;

(ii) A reading at or above 100% of LEL under a street in a wall-to-wall paved area that has gas migration and does not qualify as a grade 1 leak;

(iii) A reading between 20% and 80% of the LEL in ~~a confined space~~ an enclosure;

(iv) A reading less than 80% of the LEL in a substructure (other than gas associated substructures) from which gas could migrate;

(v) A reading of 80% or greater of the LEL in a gas associated substructure from which gas could not migrate;

~~(vi) Any reading of gas that does not qualify as a grade 1 leak that occurs on a transmission pipeline or a Type A or Type C regulated gas gathering line;~~

(vi) ~~(vii) Any leak with a leakage rate of 10 cubic feet per hour (CFH) or more that does not qualify as a grade 1 leak;~~ Is of sufficient magnitude to pose significant potential harm to the environment, applying one of the following criteria as determined by the operator:

(A) estimated leakage rate of 10 cubic feet per hour (CFH) or more, as indicated by suitable technology; or

(B) estimated ''leak extent'' (land area affected by gas migration) of 2,000 square feet or greater; or

(C) an alternative method for determining environmental significance of a leak.

~~(viii) Any leak of LPG or hydrogen gas that does not qualify as a grade 1 leak;~~ or

~~(ix)~~(vii) Any leak that, in the judgment of operating personnel at the scene, is of sufficient magnitude to justify scheduled repair within ~~six~~ 12 months or less.

(2) ~~An operator must schedule repair based on the severity or likelihood of hazard to persons, property, or the environment.~~ A grade 2 leak must be repaired/remediated within ~~six~~ 12 months of detection except as described below, or unless a shorter repair deadline is required by the operator's procedures, integrity management program, or paragraphs (c)(3) through ~~(6)~~(4) of this section. The operator must reevaluate each grade 2 leak at least once every ~~30 days~~ 6 months until it is repaired.

(i) An operator must complete repair of known grade 2 leaks existing on or before [effective date of the final rule] before [date ~~1 year~~ 36 months after the effective ~~publication~~ date of the final rule] unless an extension request has been approved under (h).

(ii) A grade 2 leak may be evaluated in accordance with paragraph (c)(2) of this section and repairs postponed if the segment containing the leak is scheduled for replacement, and is replaced, within 5 years of detection of the leak.

(3) The operator must complete repair of any grade 2 leak on a gas transmission or Type A gathering pipeline, each located in an HCA, Class 3 or Class 4 location, within ~~30 days~~12 months of detection. If repair cannot be completed within ~~30 days~~ 12 months due to permitting requirements or parts availability, the operator must ~~take continuous action to monitor and repair the leak~~ reevaluate each grade 2 leak at least once every 45 days until it is repaired/remediated.

~~(4) Each operator's operations and maintenance procedure must include a methodology for prioritizing the repair of grade 2 leaks, including criteria for leaks that warrant repair within 30 days of detection pursuant to § 192.760(c). Grade 2 leaks with a repair deadline of less than 30 days must be reevaluated at least once every 2 weeks until the repair is complete. This methodology must include an analysis of, at a minimum, each of the following parameters:~~

~~(i) The volume and migration of gas emissions;~~

~~(ii) The proximity of gas to buildings and subsurface structures;~~

~~(iii) The extent of pavement; and~~

~~(iv) Soil type and conditions, such as frost cap, moisture, and natural venting.~~

~~(5)~~ (4) Each operator must ~~take immediate and continuous action to complete repair of~~ investigate a known below ground grade 2 leak ~~and eliminate the hazard~~ when the operator becomes aware of freezing ground, heavy rain, flooding, new pavement, or other changes to the environment ~~are anticipated or occur~~ near ~~an~~ the existing grade 2 leak that may affect the venting or migration of gas and could allow gas to migrate to the outside wall of a building.

~~(6) An operator must complete repair of known grade 2 leaks existing on or before [insert~~

~~effective date of the final rule] before [insert date 1 year after the publication date of the final rule].~~

(d) *Grade 3 leaks.*

(1) A grade 3 leak is any leak that does not meet the criteria of a grade 1 or grade 2 leak. In order to qualify as a grade 3 leak, none of the criteria for grade 1 or 2 leaks must be present. Grade 3 leaks may include, but are not limited to, leaks with the following characteristics:

(i) A reading of less than 80% of the LEL in gas associated substructures from which gas is unlikely to migrate; or

(ii) Any reading of gas under pavement outside of a wall-to-wall paved area where gas is unlikely to migrate to the outside wall of a building; or

(iii) A reading of less than 20% of the LEL in ~~a confined space~~ an enclosure.

(2) A grade 3 leak must be repaired within ~~24~~ 36 months of detection, except as described below:

(i) A grade 3 leak known to exist on or before [effective date of the final rule] must be repaired prior to [date 3 years after the effective ~~publication~~ date of the final rule] unless an extension request has been approved under (h).

(ii) A grade 3 leak may be evaluated in accordance with paragraph (d)(3) of this section and repairs postponed if the segment containing the leak is scheduled for replacement, and is replaced, within ~~five~~10 years of detection of the leak.

(3) Each operator must reevaluate each grade 3 leak at least once every 12~~six~~ months until repair/remediation of the leak is complete.

(e) *Post-repair ~~inspection~~ re-check.*

~~(1) A leak repair is considered to be complete when an operator obtains a gas concentration reading of 0% gas at the leak location after a permanent repair.~~

(1)~~(2)~~ An operator must conduct a post-repair leak ~~inspection~~ re-check ~~at least 14 days after but~~ no later than 30 days after the ~~date of the~~ repair ~~to determine if the repair was complete,~~ if 0% gas concentration readings cannot be achieved after repair due to residual gas in the soil.

(2)~~(3)~~ If a post-repair ~~inspection~~ re-check shows a gas concentration reading greater than 0%, the ~~repair is not complete,gas~~ operator must take the following actions:

(i) If the re-check shows a gas concentration lower than the most recent read, the operator must perform a re-check within 30 days and continue re-checking at least once every 30 days until there is a gas concentration reading of 0%.

(ii) If the re-check shows a gas concentration higher than (or equal to) the most recent read, the operator must investigate and repair or grade the leak according to paragraph § 192.760(b), § 192.760(c), or § 192.760(d).

~~i) if the operator's post repair re-check finding 0% gas reads (no further action required); 2) re-checks finding gas reads that are lower than previous read (schedule follow-up re-check); or 3) re-checks finding reads greater than (or equal to) previous read (indicative of new or ongoing leakage, grade and schedule reevaluation/repair accordingly). (i) If the post repair inspection finds gas concentrations or migration indicating that the potential for a grade 1 or grade 2 condition leak exists, the operator must re-inspect the repair and take immediate and continuous action to eliminate the hazard and complete repair;~~

~~(ii) If the operator's post repair inspection does not find a gas concentration reading of 0% at the leak location, and a grade 1 or grade 2 condition does not exist, then the operator must remediate the repair and re-inspect the leak within 30 days and continue reevaluating the leak at least once every 30 days until there is a gas concentration reading of 0%. Leak repair must be complete within the repair deadline for a grade 3 leak under § 192.760(d)(2), or for a downgraded leak, the repair deadline under § 192.760(g).~~

(3)~~(4)~~ A post repair ~~inspection~~ re-check is not required for: (i) any leak that is eliminated by routine maintenance work—such as adjustment or lubrication of aboveground valves, or tightening of packing nuts on valves with seal leaks;~~—and is~~ (ii) a grade 3 leak or one that occurs on an aboveground pipeline facility~~.~~; (iii) repairs for excavation damages; (iv) remediation of leak involving pipeline replacement; or (v) remediation where the leaking pipeline was abandoned.

(f) *Upgrading leak grades.*

If at any time an operator receives information that a higher-priority grade condition exists in connection with a previously graded leak, the operator must upgrade that leak to the higher-priority grade. When an operator upgrades a leak to a higher-priority grade, the time period to complete the repair is the earlier of either the remaining time based on its original leak grade or the time allowed for repair under its new leak grade measured from the time the operator received the information that a higher priority grade condition exists.

(g) *Downgrading leak grades.*

A leak may not be downgraded to a lower priority leak grade unless:

(i) A~~a~~ temporary repair to the pipeline has been made or a permanent repair was attempted but gas was detected during the post-repair re-check ~~inspection~~ under paragraph (e) of this section, or

(ii) The leak was initially graded incorrectly. Operators must address any additional necessary actions through Subpart N for individuals that incorrectly grade leaks.

In these cases ~~this case~~, the time period for repair is the remaining time allowed for repair under its new grade measured from the time the leak was first detected.

(h) *Extension of leak repair/remediation.*

An operator may request an extension of the leak repair deadline requirements for an individual grade 2 leak or grade 3 leak with advance notification to and no objection from PHMSA pursuant to § 192.18. The operator's notification must show that the delayed repair timeline would not result in an increased risk to public safety, as well as that either the required repair deadline is impracticable, ~~or~~ that remediation within the specified time frame would result in the release of more gas to the environment than would occur with continued monitoring, or that a replacement project is pending and would negate the need to make any repair. The notification must include the following:

(1) A description of the leaking facility including the location, material properties, the type of equipment that is leaking, and the operating pressure;

(2) A description of the leak and the leak environment, including gas concentration readings, leak rate if known, class location, nearby buildings, weather conditions, soil conditions, and other conditions that could affect gas migration, such as pavement;

(3) A description of the alternative Repair/remediation schedule and a justification for the same; and

(4) Proposed emissions mitigation methods, monitoring, and repair schedule.

(i) *Recordkeeping.*

(1) Records ~~of the complete history of the investigation and grading of each leak must be retained for 5 years after the final post repair inspection is completed under paragraph (e) of this section. These records include all records~~ documenting the leak grading~~, monitoring, inspections~~ re-checks

completed under paragraph (e) of this section, upgrades, and downgrades must be retained for 5 years after final post-repair re-check.

(2) Records of the ~~detection, remediation, and repair of the leak must be retained for the life of the pipeline. This must include~~ the date, location, and description of each leak detected, and the date and repair or remediation method applied ~~of the same, made on the pipeline.~~must be retained for the life of the pipeline for gas transmission and gas distribution pipelines, unless a shorter timeline is prescribed by § 192.709.

§ 192.763 Advanced Leak Detection Program

(c) Advanced Leak Detection Program (ALDP) elements. Each operator must have and follow a written ALDP that includes the following elements:

(2) Leak detection equipment.

(i) The ALDP must ~~include a list of~~ identify operator-approved leak detection equipment used to perform ~~in operator~~ leakage surveys and other leak detection activities~~, pinpointing leak locations, and investigating leaks~~.

(ii) Unless using non-optical continuous monitoring system (e.g., acoustical or pressure monitoring systems) or soap solution, ~~L~~leak detection equipment used for leakage surveys~~, pinpointing leak locations, investigating, and inspecting leaks~~ must have a minimum sensitivity capability of one of the following:

(A) 5 parts per million for each gas being surveyed using handheld leak detection equipment, unless described in § 192.763(a)(1)(ii)(C);

(B) 500 parts per million (or 10 kg/hr mass flow equivalent) for each gas being surveyed using infrared or laser-based leak detection equipment; mobile, aerial, or satellite-based platforms; or using fixed continuous monitoring sensors within buildings;

(C) 500 parts per million for each gas being surveyed within buildings using handheld leak detection equipment; or

(D) sensitivity otherwise meeting the requirements of 40 C.F.R. Part 60, subpart OOOO for optical gas imaging or equivalent

Before using this equipment in a leakage survey, t~~T~~he operator must validate the sensitivity at which the survey is to be conducted ~~of this equipment before using the device in a leakage survey~~ by testing in accordance with manufacturer's instructions~~with a known concentration of gas.~~

(iii) Records validating that the ALDP equipment meets the minimum sensitivity requirements must be maintained for at least 5 years after the date that equipment is no longer used by the operator.

~~(iii) Leak detection equipment must be selected based on a documented analysis considering, at a minimum, the state of commercially available leak detection technologies and practices, the size and configuration of the pipeline system, and system operating parameters and environment. At a minimum, operators must analyze the effectiveness of the following technologies for their systems:~~

~~(F) The use of handheld leak detection equipment capable of detecting and pinpointing all leaks of 5 parts per million or more; when measured within 5 feet of the pipeline or within a wall-to-wall paved area, in conjunction with locating equipment to verify the tools are sampling the area within 5 feet of the buried pipeline. The procedure must include sampling the atmosphere near cracks, vaults, or any other surface feature where gas could migrate;~~

~~(G) Periodic surveys performed with leak detection equipment mounted on mobile, aerial, or satellite-based platforms that, in conjunction with confirmation by hand-held equipment, is capable of detecting and pinpointing all leaks of 5 parts per million or more; when measured within 5 feet of the pipeline, or within a wall-to-wall paved area;~~

~~(H) Periodic surveys performed with optical, infrared, or laser-based leak detection equipment that can sample or inspect the area within 5 feet of the pipeline, or within a wall-to-wall paved area, capable of detecting and pinpointing all leaks of 5 parts per million or more;~~

~~(I) Continuous monitoring for leaks via stationary sensors, pressure monitoring, or other means of continuous monitoring that provide alarms or alerts and that, in conjunction with confirmation by hand-held equipment, is capable of detecting and pinpointing all leaks of 5 parts per million or more when measured within 5 feet of the pipeline, or within a wall to-wall paved area; and~~

(J) ~~Systematic use of other commercially available technology capable of detecting and pinpointing all leaks producing a reading of 5 parts per million or more within 5 feet of the pipeline, or within a wall-to-wall paved area.~~

(5) Leak detection practices. At a minimum, an operator must have and follow written procedures within their ALDP for:

(iv) Performing leakage surveys~~. Operators must have procedures for performing leakage surveys~~ required for §§ 192.706 and 192.723 using equipment identified in ~~each selected leak detection technology as described in~~ paragraph § 192.763(a)(1). The procedures must define any environmental ~~and~~or operational condition~~s~~ limits for the use of the equipment ~~which each leak detection technology is and is not permissible~~. The operator's procedures should be in alignment with ~~must follow~~ the leak detection equipment manufacturer's instructions ~~for survey methods and allowable environmental and operational parameters~~.

(v) ~~Pinpointing and investigating leaks. The location of the source of each l~~Leak survey indications on ~~an~~ onshore pipelines or any portion of an offshore pipelines above the waterline must be ~~pinpointed and~~ investigated with ~~handheld~~ leak detection equipment or soap testing. Leak indications on onshore waterbody crossings and offshore pipelines below the waterline may be pinpointed with human senses.

(vi) Calibrating equipment in accordance with the manufacturer's written recommendations. ~~Validating performance. Operators must have procedures validating that leak detection equipment meets the requirement of paragraph (a)(1)(ii) of this section. The operator must have procedures for validating the sensitivity of the equipment before initial use by testing with a known concentration of gas and at the required offset conditions of 5 feet. Records validating equipment performance must be maintained for five years after the date the device is no longer used by the operator.~~

~~(iv) Maintaining and calibrating leak detection equipment. At a minimum, procedures must follow the equipment manufacturer's instructions for calibration and maintenance. Leak detection equipment must be recalibrated or replaced following any indication of malfunction.~~ Records demonstrating ~~validating~~ equipment calibration ~~and failures indicating recalibration is necessary~~ must be maintained for 5 years ~~after the date the individual device is retired by the operator~~.

(6) Leakage survey frequency shall not exceed the defined intervals required by~~. Leakage survey frequency must be sufficient to detect all leaks that have a sufficient release rate to produce a reading of 5 parts per million or more of gas when measured from a distance of 5 feet or less from the pipeline, or within a wall to- wall paved area, but may be no less frequent than required in~~ §§ 192.706 and 192.723. Leak survey intervals may need to be shorter than those requirements based on known factors such as ~~L~~less sensitive equipment, challenging survey conditions, or facilities known to leak based on their material, design, or past operating and maintenance history ~~may require more frequent surveys to detect leaks consistent with paragraph (b) of this section~~.

(7) Program ~~Periodic~~ evaluation and improvement. ~~The ALDP must include procedures and records showing the operator is meeting all of the program requirements.~~

(iv) The operator must evaluate the ALDP at least once each calendar year but with a maximum interval not to exceed 15 months.

~~(ii) The operator must make changes to any program elements necessary to locate and eliminate leaks and minimize releases of gas.~~

(v) When considering changes to program elements, operators must ~~analyze, at a minimume~~ evaluate, the impact (if any) of novel pipeline types, locations, materials, or media on the operator's system that may influence the performance of the leak detection equipment used, and the adequacy of the leakage survey procedures~~, advances in leak detection technologies and practices, the number of leaks that are initially detected by the public, the number of leaks and incidents, and estimated emissions from leaks detected pursuant to this section~~.

(vi) The operator must document any improvements made~~needed~~ to the program.

(d) ~~Advanced leak detection performance standard. Each operator's ALDP described in paragraph (a) of this section must be capable of detecting leaks that have a sufficient release rate to produce a reading of 5 parts per million or more of gas when measured from a distance of 5 feet or less from the pipeline, or within a wall-to-wall paved area.~~

~~(3) The performance of the ALDP equipment must be validated and documented with engineering tests and analyses.~~

~~(4) Records validating that the ALDP meets the performance standard must be maintained for at least 5 years after the date that ALDP is no longer used by the operator.~~

Alternative advanced leak detection performance standard. ~~For gas pipelines other than natural gas pipelines, and for natural gas transmission, offshore gathering, and Types A, B, and C gathering pipelines located in Class 1 or Class 2 locations,~~ A~~a~~n operator may use an alternative ALDP performance standard (and supporting leak detection equipment) with prior notification to, and with no objection from, PHMSA in accordance with § 192.18. PHMSA will only approve a notification if operator, in the notification, demonstrates that the alternative performance standard is consistent with pipeline safety and equivalent to the standard in paragraph ~~(b)~~ (a) of this section for reducing greenhouse gas emissions and other environmental hazards. The notification must include:

(1) Mileage by system type;

(2) Known material properties, location, HCAs, operating parameters, environmental conditions, leak history, and design specifications,

including coating, cathodic protection status, and pipe welding or joining method;
(3) The proposed performance standard;
(4) Any safety conditions, such as increased survey frequency;
(5) The leak detection equipment, procedures, and leakage survey frequencies the Operator proposes to employ;
(6) Data on the sensitivity and the leak detection performance of the proposed Alternative ALDP standard; and
(7) The gas transported by the pipeline.

~~§ 192.769 Qualification of leakage survey, investigation, grading, and repair personnel.~~

~~Only individuals qualified under subpart N of this part may conduct leakage survey, investigation, grading, and repair. Individuals qualified under subpart N must also possess training, experience, and knowledge in the field of leakage survey, leak investigation, and leak grading, including documented work history or training associated with those activities.~~

§ 192.770 ~~Minimizing~~ Reducing emissions from gas transmission pipeline blowdowns.

(a) Except as provided in paragraph (b) of this section, when an operator performs any intentional release of gas that would exceed 1 MMCF without mitigative action (including blowdowns or venting for scheduled repairs, construction, operations, or maintenance) from a gas transmission pipeline, the operator must prevent or ~~minimize~~ reduce the release of gas to the environment through one or more of the following methods:

(1) Isolating the smallest optimal section of the pipeline necessary to complete the task by use of valves or the installation of control fittings;
(2) Routing gas released from the pipeline from the nearest isolation valves or control fittings to a flare or to other equipment as fuel gas;
(3) Reducing pressure by use of inline compression;
(4) Reducing pressure by use of mobile compression to a segment or storage vessel adjacent to the nearest isolation valves;
(5) Transferring the gas to a segment of a lower pressure pipeline system adjacent to the nearest isolation valves; or
(6) Employing an alternative method demonstrated to result in a release volume reduction of at least 50% compared to venting gas directly to the atmosphere without mitigative action.

(b) An operator is not required to comply with the provisions of paragraph (a) of this section during an event that ~~activates its emergency plan under § 192.615(a)(3) when such minimization~~ would delay emergency response, or, in the judgment of the operator, would result in a safety risk or impact to customers or production operators ~~during pipeline assessments or maintenance~~. Each ~~emergency~~ release conducted without mitigation must be documented, including the justification for release without mitigation.

~~(c) Operators must document the methodologies used in paragraph (a) of this section and describe how the methodologies minimize the release of gas to the environment.~~

§ 193.2523 Reducing ~~Minimizing~~ emissions from blowdowns and boiloff.

(a) Except as provided in paragraph (b) of this section, an operator of an LNG facility must reduce ~~minimize~~ intentional emissions of natural gas from LNG facilities that would exceed 1 MMCF without mitigative action, including tank boiloff or blowdowns for repairs, construction, operations, or maintenance. The operator must reduce ~~minimize~~ the release of natural gas to the environment by use of one or more of the following methods:

(1) Isolating ~~a smaller section of the~~ piping segments by use of valves or the installation of control fittings;

(2) Routing gas released from the facility to a flare, or to other equipment for use as fuel gas;

(3) Transferring gas or LNG to a storage tank or local pressure vessel; or

(4) Employing an alternative method demonstrated to result in release volume reductions of at least 50% compared to venting gas directly to the atmosphere without mitigative action.

(b) An operator is not required to comply with the provisions of paragraph (a) of this section during an emergency resulting in the activation of their emergency procedures under § 193.2509. An operator must document each emergency release without mitigation described in paragraph (b) of this section, including the justification for release without mitigation.

(c) The operator must document the method or methods used and describe how those methods reduce ~~minimize~~ the release of natural gas to the environment.

§ 193.2624 Leakage surveys.

(a) Except as provided in paragraph (e) of this section, ~~E~~each operator ~~of an LNG facility, including mobile, temporary, and satellite facilities~~ must conduct periodic ~~methane~~ leakage surveys~~, on equipment and~~ of designated components ~~within their facilities~~ containing ~~methane~~ gas or LNG~~,~~ at least four times each calendar year, with a maximum interval between surveys not exceeding 4 ½ months, using leak detection equipment. ~~Leak detection equipment must be capable of detecting and locating all methane leaks producing a reading of 5 parts per million or more of within 5 feet of the component or equipment surveyed.~~

(b) Operators must have written procedures providing for each of the following:

(1) Validating the leakage survey equipment and performing leakage surveys consistent with the equipment manufacturer's instructions for survey methods and allowable environmental and operational parameters;

(2) Validating the sensitivity of this equipment ~~by the operator~~ before initial use by testing ~~with a known concentration of gas at a required offset condition of 5 feet~~; ~~and~~

(3) Calibrating the equipment consistent with the equipment manufacturer's instructions for calibration and maintenance. Leak detection equipment must be recalibrated or replaced following any indication of malfunction; and~~.~~

(4) Designating the components subject to the periodic leakage survey requirements, not including any components that are inaccessible, unsafe to monitor, or difficult to monitor during one or more survey intervals.

(c) Each operator must maintain records of the leak survey and equipment sensitivity validation and calibration for five years after the leakage survey.

(d) Operators must review the results of the methane leakage surveys and address any methane leaks and abnormal operating conditions in accordance with their written maintenance procedures or abnormal operating procedures.

(e) The requirements in this section do not apply to:

(1) An LNG facility subject to a leak detection and repair program pursuant to a statute or regulation administered, or a permit or authorization issued, by the U.S. Environmental Protection Agency or another federal, state, or local agency; or

(2) A mobile or temporary LNG facility.

XI. Conclusion

The Associations commend PHMSA's continuing commitment to pipeline safety and appreciates the opportunity to comment on the PHMSA Gas Leak Detection and Repair Proposed Rule. Safety continues to be the industry's number one priority and commitment.

The Associations recognize the challenges associated with developing a comprehensive regulation that would address such a variety of topics. The Associations support the intent of the proposed rule and share PHMSA's goal of addressing methane emissions. However, as discussed in its comments, the Associations have significant concerns with several components of PHMSA's proposed rule and its proposed implementation of the Congressional mandates included in the PIPES Act of 2020.

The Associations remain committed to working with PHMSA to address our concerns with the proposed requirements, to meet the Congressional mandates. We also look forward to providing additional information that may be needed to help PHMSA move forward with this rulemaking.

Respectfully submitted
Date: August 16, 2023

Christina Sames, *Senior Vice President, Operations and Engineering*
American Gas Association
400 North Capitol Street, NW
Washington, D.C. 20001
(202) 824-7214
csames@aga.org

Dave Murk, *Senior Director, Pipelines*
American Petroleum Institute
200 Massachusetts Avenue NW
Washington, D.C. 20001
(202) 682-8080
murkd@api.org

Erin Kurilla, *Vice President, Operations and Safety*
American Public Gas Association
201 Massachusetts Avenue, NE
Washington, D.C. 20002
(202) 905-2904
ekurilla@apga.org

Ben Kochman, *Director of Pipeline Safety Policy*
Interstate Natural Gas Association of America
25 Massachusetts Avenue, NW Suite 500N
Washington, D.C. 20001
(202) 216-5913
bkochman@ingaa.org

Matthew Hite, *Senior VP of Government Affairs*
GPA Midstream Association
505 9th Street NW, Suite 602
Washington, D.C. 20004
(202) 279-1664
mhite@gpamidstream.org

Jose Costa, *President & CEO*
Northeast Gas Association
1800 West Park Drive, Suite 340
Westborough, MA 01581
(202) 279-1664
jcosta@northeastgas.org

Robert Benedict, *VP Petrochemicals & Midstream*
American Fuel & Petrochemical Manufacturers
rbenedict@afpm.org