August 16, 2023

US Department of Transportation
Docket Management System
West Building, Ground Floor, Room W12-140
1200 New Jersey Ave., SE
Washington, DC 20590-0001

Attention: Docket No. PHMSA-2021-0039

Re: In the Matter of the Gas Pipeline Leak Detection and Repair Notice of Proposed Rulemaking 49 CFR Parts 191, 192, and 193, Comments of The Northeast Gas Association to PHMSA Notice and Request for Revision.

Via Email

Dear Sir or Madam:

The Northeast Gas Association[1] ("NGA") respectfully submits the following comments and request for revision on behalf of our natural gas local distribution company members ("NGA LDCs") in response to the above referenced Notice.

PHMSA proposes regulatory amendments that implement congressional mandates in the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 ("Pipes Act of 2020") to reduce methane emissions from new and existing gas transmission pipelines, distribution pipelines, regulated (Types A, B, C and offshore) gas gathering pipelines, underground natural gas storage facilities, and liquefied natural gas facilities. Among the proposed amendments for part 192-regulated gas pipelines are strengthened leakage survey and patrolling requirements; performance standards for advanced leak detection programs; leak grading and repair criteria with mandatory repair timelines; requirements for mitigation of

[1] NGA is a regional trade association that focuses on pipeline safety and safety culture, education and training, technology research and development, operations, planning, and increasing public awareness of natural gas in the Northeast U.S. NGA supports a culture of pipeline safety and environmentally responsible energy delivery practices. NGA represents natural gas distribution companies, transmission companies, liquefied natural gas suppliers and associate member companies. Its member companies provide natural gas service to 14 million customers in 9 states (CT, MA, ME, NH, NJ, NY, PA, RI, VT).

1800 West Park Drive., Ste. 340, Westborough, MA 01581 20 Waterview Blvd., 4th Floor, Parsippany, NJ 07054
781.455.6800, 973.265.1900
www.northeastgas.org

emissions from blowdowns; pressure relief device design, configuration, and maintenance requirements; and clarified requirements for investigating failures. Finally, PHMSA proposes expanded reporting requirements for operators of all gas pipeline facilities within DOT's jurisdiction, including underground natural gas storage facilities and liquefied natural gas facilities. NGA supports initiatives that further enhance pipeline safety value including broader industry recognition and incorporation of operating practices that support managing and reducing methane emissions risk as a component of pipeline safety.

NGA continues to work collaboratively with the American Gas Association (“AGA”), American Public Gas Association (“APGA”), Interstate Natural Gas Association of America (“INGAA”), American Petroleum Institute (“API”), GPA Midstream, and American Fuel & Petrochemical Manufacturers (“AFPM”) (jointly “the Associations”) and other participating organizations in developing Joint Industry Comments supported by a broad spectrum of stakeholders from across the industry. NGA supports these comments and offers the following additional comments for consideration. The comments submitted herein build upon the Associations comments focusing on proposed code sections that will have substantial regional Local Distribution Company (“LDC”) impacts for NGA members and as such require further clarification for adoption and/or revisions to achieve intended goals of maximizing public safety value while supporting a practical focus on methane emission reductions.

General Comments:

1. Leak Detection and Repair Final Rule Proposed 6-Month Effective Date and Management of Change

PHMSA proposes only a 6-month effective date for the provisions within the NPRM. The proposed requirements include a broad range of changes to operator’s procedures and will result in substantial management-of-change process considerations for data collection practices, work management systems, information technology systems, equipment, staffing, training, bargaining unit contract negotiations/agreements and Operator Qualification (“OQ”) programs. Operators will need significantly more than 6 months to take all the necessary actions for compliance. These changes are comprehensive, for example, will require a restructuring of how patrols and surveys are performed in the natural gas industry, potential restructuring of previously approved rate-based pipe replacement programs and how leaks are determined and ultimately addressed. Proposing a uniform effective date of six months is not reflective of the complexity of various components of the proposal and does not address the myriad of management-of-change considerations necessary to ensure sustainable results the proposal is intended to provide.

NGA is supportive of a logical phase-in approach to the final rule with effective dates for different provisions within the rule based upon the proposed changes in each Subpart within a 3-year glidepath. While some specific elements of the proposal may be implemented within 6 months, some Subparts warrant a 1-year, 18-months, or longer timeframes based on the significance of the needed modifications to an operators' training, OQ, leak management, data collection, reporting systems, procurement, standards manuals, jurisdictional rate agreements etc.

Implementation timeframes will vary as the complexity is commensurate with the nature of organization specific assets and operations. Operators need sufficient time to develop management of change plans that will provide a roadmap addressing final rule requirements. The complexity of these changes to specific operations varies greatly based on the specific regulation that is being added or changed. NGA respectfully requests that the final rule feature effective dates that are practical and reasonable to facilitate sustainable management-of-change and to ensure a compliance glidepath that meets the intent of the proposal. Operators cannot begin implementation efforts until they know the exact requirements in the Final Rule. Operators cannot speculate how the requirements will be modified throughout the rulemaking process and, therefore, do not change procedures or operating policies based on the NPRM.

If a 36-month phase-in glidepath is not acceptable to PHMSA, while not desirable, at a minimum, NGA is recommending a Stay of Enforcement be considered for a period of 36 months following final rule effective date(s) to allow operators adequate time to implement changes in a manner that will maximize compliance. In consideration of a 36 month Stay, operators would agree to develop and implement a Leak Detection and Repair ("LDAR") Management of Change Compliance Workplan ("MOC Plan") within 90 days of the publication of the final rule. The plan would include detailed analysis of organization specific impacts, training, OQ implications, O&M Plan revisions audit and QA/QC Plan revisions, contractor training and qualification, DIMP/TIMP plan revisions contractual and supply chain considerations and cost recovery rate plan revision considerations. The proposed MOC Plan would be subject to review upon request.

NGA also recommends 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.

In summary, taking a *"one size fits all* "implementation approach with arbitrary, policy driven implementation dates does not address the disproportionate operational impacts these sweeping changes represent to our members, particularly within the northeast region. Considering specific regional variables such as the total population of legacy pipe materials identified for replacement and the associated regional complexity of executing work - permitting requirements and local jurisdictional resistance to allowing work on pipelines, state commissions re-thinking rate case recovery options due to policy decarbonization pressure etc. all need to be carefully integrated into each operator specific LDAR MOC Compliance Workplan. NGA strongly supports the Associations recommendation that PHMSA provide a three-year effective date of the final rule running from the first day of the calendar year.

2. Regulatory Overlap; Coordination and Consideration of Existing and Proposed Jurisdictional and Other Federal Regulatory Requirements

Natural gas and the extensive infrastructure network that supports it has been a cornerstone 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 climate change and reducing emissions has complemented the natural gas utility industry's focus on safety and reliability and therefore, enabled a steep decline in methane emissions through pipeline replacement and modernization efforts. The collaboration of policymakers with parallel goals of infrastructure modernization and resulting emission risk reductions is best summarized in the 2020 NARUC report Natural Gas Distribution Infrastructure Replacement and Modernization: A Review of State Programs[2].

NGA and our members are committed to working with policymakers in applying a *good science common sense approach* to reducing GHG emissions through smart innovation, new and modernized infrastructure, and advanced technologies that maintain reliable, resilient, and cost-effective energy service choices for consumers. In collaboration with policymakers and regulators, NGA members continuously invest in the modernization of the northeast regional natural gas delivery infrastructure to distribute safe, reliable, and cost-effective energy in an environmentally responsible manner. Methane emissions from natural gas distribution systems across the country have declined by 70 percent from 1990 – 2021.[3] The data reflects the work NGA member gas utilities have been doing to modernize their systems and implement leading practices.

NGA understands PHMSA's position to address aspects of the Pipes Act of 2020 and where reasonable, enhance existing pipeline safety regulations to address emission risks as well as

[2] National Association of Regulatory Utility Commissioners (NARUC) Report January 2020
[3] *See* 2023 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2020 (April 15, 2023) (2022 GHGI).

public safety risk. Several of PHMSA's proposals conceptually overlap with existing industry voluntary programs (e.g., EPA STAR Program) as well as fundamental regulatory requirements of EPA in 40 CFR Part 98 Subpart W.

Further complicating the federal layers of regulation regarding existing and emerging emission monitoring and mitigation regulations are recently enacted state jurisdictional requirements such as the New York State Department of Environmental Protection Air Pollution and Control Regulatory Revisions NYSDEC Rule 203, in Massachusetts, 220 CMR 114.00 Uniform Natural Gas Leaks Classification and recently enacted statutes in New Jersey, Section 14:7-1.19 - Gas Leak Classification and Repair just to highlight three northeast regional requirements.

PHMSA has recognized the importance of regulatory coordination as industry and policymakers alike pursue parallel goals to minimize greenhouse gas emissions while ensuring pipeline safety goals are achieved. For example, PHMSA proposes to exempt pipeline compressor stations from leak repair, survey, and ALDP obligations to the extent they are subject to EPA regulations under the Clean Air Act. NGA agrees with the logic in minimizing overlap of regulatory requirements where these requirements have similar intent to extract the greatest degree of public safety value and to avoid unintentional conflicting requirements.

However, PHMSA has not applied this logic consistently throughout the proposal which will ultimately result in duplication of monitoring, repair, and reporting requirements. Similarly, these duplicative, non-value-added regulatory requirements will only serve to add additional confusion and unnecessary cost burdens to the consumer. A wholistic end-to-end cost assessment associated with these compounding regulatory requirements has not been adequately captured in the Proposal Regulatory Impact Analysis ("PRIA") and as a result, total cost implications are misleading. A key overall safety value consideration was overlooked in the PRIA including analysis of the end-to-end carbon footprint of proposed regulatory changes. For efficiency and consistency purposes, PHMSA should also consider incorporating facilities that are subject to these confounding federal and state regulations in an expanded section 192.703(d) exception. Similar logic in the 192.703(d) exception should also apply to distribution facilities such as LNG peak shaving plants, city gate and pressure regulation stations already incorporated in EPA and state regulatory mandates.

Last, 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 would otherwise be accounted for by the proposed expanded section 192.703(d) referenced above to accommodate any delays in finalizing the EPA rule and minimize duplicative efforts.

If PHMSA proceeds with requiring operators of these facilities to comply with the Final Rule first and then subsequently Quad-Ob ("OOOOb") or Quad-Oc ("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.[4] 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.[5] 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. In summary, PHMSA's incorporation of environmental protection jurisdiction in this proposal will result in unaccounted complexity due to lack of synchronization with other emerging federal regulations unless logic is incorporated in the final rule that allows for exceptions for those facilities that must conform with a multitude of confounding requirements.

3. Notice of Proposed Rulemaking (NPRM) Code Section Comments

3.1 Leak Definition, Grading and Repair

Leak or Hazardous Leak - PHMSA's Proposed Definition of a Leak is Overbroad and Inconsistent with Section 113 of the PIPES Act of 2020.

PHMSA proposes to define both leaks and hazardous leaks 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."[6] The agency proposes to treat all leaks as hazardous and apply this new definition across all Part 192 subparts with the exception of the underground natural gas storage requirements (section 192.12) and the integrity management requirements (subpart O and P).

NGA contends not all leaks are hazardous. Treating all leaks as hazardous dilutes the importance of a prompt response when there is an immediate risk to life or property. Congress clearly acknowledged the existence of <u>non-hazardous</u> leaks in section 113 of the PIPES Act. Congress directed PHMSA to focus its leak detection and repair programs on leaks that are "hazardous to human safety or the environment" or "have the *potential* to become explosive or otherwise hazardous to human safety."[7] Congress also recognized that some "leaks [are] so small that

---

[4] PRIA, 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.")
[5] 88 Fed. Reg. 31,890, at 31,939; *See also,* 88 Fed. Reg. 31,939, fn. 245.
[6] Proposed 192.3.
[7] 49 U.S.C. § 60102(q)(2)(B)(i)-(ii).

[they] pose no potential hazard" and therefore do not need to be repaired immediately.[8] PHMSA's proposal implied or otherwise, to treat *all* leaks as hazardous, is not consistent with this language.

PHMSA's Proposed Definition of a Leak is Also Contrary to PHMSA's Well-Developed Position on Hazardous Leaks.

The agency asserts in the NPRM that its regulations have lacked "meaningful guidance regarding which leaks are hazardous"[9] which may be misleading. 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."[10] PHMSA has also encouraged gas transmission operators to use this definition.[11] 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.[12] 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.[13] 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"[14]

PHMSA may not have completely considered the impact that the conflation of these two definitions would have on the tracking and trending of leak data by individual operators and across the industry. Any change to definitions in Part 191 or section 192.3 must be mirrored in the instructions for §§ 191.11 and 191.17 annual reports.

---

[8] The congressional mandate for advanced leak detection technologies requires a schedule for repairing each leaking pipe "***except a pipe with a leak so small that it poses no potential hazard…***" 49 U.S.C. § 60102(q)(3)(A)(iii)(emphasis added).
[9] 88 Fed. Reg.at 31,916.
[10] 49 C.F.R. § 192.1001; Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines, 74 Fed. Reg. 63,906, 63,934 (Dec. 4, 2009).
[11] 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.
[12] Instructions for Form PHMSA F-7100.2-1 at 14.
[13] 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.
[14] *Id.*

Recommended Definition of a Leak

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

1) Hazardous to human safety or the environment; or
2) Have the potential to become explosive or otherwise hazardous to human safety.[15]

NGA recognizes 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, NGA supports the following enhanced definition of a leak:

> ***Leak*** **means any unintentional release of gas, detectable by equipment, odor, sight or sound, from a pipeline or structure 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, NGA strongly disagrees with PHMSA's proposal to make "hazardous leaks" and "leaks" synonymous and recommend codification for two separate definitions: "leak" and "hazardous leak."

NGA believes that criteria for "hazardous leaks" should remain primarily focused on existing or probable hazard to persons or property, as this determination is one that can 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, NGA recommends 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.

---

[15] 49 U.S.C. § 60102(q)(2)(B)(i)-(ii).

PHMSA Should Replace 'Uncontrolled' with 'Unintentional'.

PHMSA should reconsider use of the term "uncontrolled" in defining a leak. It is concerning to NGA as with 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 – in the manner that those devices were intended, designed, and constructed to safely release gas – are not to be considered "uncontrolled."

PHMSA Should Remove the Reference to 'Touch' to Identify a Leak.

NGA respectfully requests that PHMSA not refer to an unsafe practice of identifying leaks by touch. Placing a digit or a portion of the hand in the path of a leak is dangerous and is not a practice that operators use or condone.

Leak Grading Requirements

General Concerns

Using its definition of a leak, NGA proposes and encourages a distinction in the grading requirements between existing or probable hazards to public safety (Grade 1) and probable future hazards to public safety (Grade 2) while considering environmental emission risk criteria for driving repairs to non-hazardous Grades 3. NGA supports the Associations Grading proposals which are generally consistent with and address the intent of PHMSA's proposal. Further, NGA recommends considering the *proximity of leak indications to buildings or structures* as additional criteria similar to some existing state code requirements[16] which have proven to be effective in protecting the public and property. It's only logical that these criteria be included in distinguishing the potential for a leak to become a hazardous leak. NGA supports PHMSA's application of grading requirements as being limited to confirmed leaks (and not merely investigations of leak indications) for the following reasons.

Leak investigations are commonly triggered by one of three events: a customer odor call for a suspected gas leak, a gas alarm from a residential gas detector or methane indications from a scheduled leak survey that has been conducted. 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

[16] *See NYS Requirements in 16 NYCRR Part 255.*

gas odor. It is important to note that not all odor calls result in the discovery of a graded natural gas leak. 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, existing operator specific procedures require responders to assess the situation (determine potential public safety 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 that are assessed fit-for-purpose by operators are used during these surveys to identify the presence or indication of methane, which can help locate potential leaks that may not be immediately recognized by human senses, such as smell, sight, or sound.

Leak pinpointing is a required precursor to accurately grading leaks and thus, determining appropriate responses from the operator. It involves precisely locating the source of a gas leak using fit-for-purpose specialized instruments and tools and a sampling process defined within an operator's specific procedure(s). 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 as defined within a leak grading process.

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, § 192.703(a)(3) requires an operator to determine a leak grade before a repair is made. The requirement to determine leak grade may unnecessarily delay repair of a leak and impede the mitigation of risk to public safety. Therefore, an exception should be made in § 192.703(a)(3) for those leaks which are eliminated through immediate and continuous action by operator personnel at the scene.

Grade 2 Leaks

NGA agrees with the Associations concerns regarding proposed Grade 2 leak criteria in the NPRM specifying operators to determine if actual leakage rates exceed 10 cubic feet per hour (cfh) is not practical when initially responding to a leak for several reasons:

a. Most of the industry does not have the resources to equip field personnel who respond to odor calls with instruments that can make these precise volumetric measurements of leaks. Where available, this type of equipment is usually only employed for mobile leak surveying.

b. 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.
c. The technology has not yet evolved to the point of accurately *and* consistently measuring flow rates from a leaking pipeline.
d. 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 also the number that are below grade (thus requiring excavation, exposure, and measurement of the leakage). 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.
e. 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 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 fit-for-purpose evaluation options 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 defined thresholds for estimated leakage rates, but also (consistent with precedent[17] in state pipeline safety regulations) options to assess and prioritize emissions estimates/risk based on leakage surface measurements that define impact and extent in square feet[18]. operators must be given latitude to define and utilize alternative

---

[17] 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.*
[18] Appendix A - Final Report GTI Project Number 22509-3, 2019 Emission Factor Pilot Study, August 2020

methods for determining whether non-hazardous leaks should be classified as Grade 2 leaks based on the potential for environmental risk, according to the operator's unique judgment, skills, 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, the winter period 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 often occur, making it challenging to complete repairs within the designated timeframe. Paving moratoriums, highway and railroad permits, and environmental matters can also affect the timing of repairs. These factors must be considered to ensure realistic and achievable repair timeframes.

Additionally, extending the repair interval for Grade 2 leaks will allow operators to leverage project bundling more fully. 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[19] 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 and less feasible.

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 industry believes 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.

Grading Criteria Considerations

NGA respectfully requests PHMSA considers the following enhancements to proposed grading criteria. This criteria is based on a strategic combination of grading fundamental principles found in Gas Piping Technology Committee ("GPTC"), recommendations proposed in the Associations comments and those found within the NPRM proposal as well as existing state regulations.

[19] 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*

Additionally, NGA requests that PHMSA acknowledge and consider that existing state leak grading programs do not all align with the measurement criteria PHMSA is proposing.
Even in as simple of a measurement as %LEL versus % gas in air, operators with extensive procedure, software, training and qualification material would be forced to modify their existing practices. Further, in some state jurisdictions, leak grading is addressed by state law, outside of pipeline safety regulation requirements, compounding the complexity of overlapping compliance and reporting requirements.

NGA feels the following recommendations address both public safety concerns, primarily of *ignition risk* in balance with considerations addressing *emissions risk*.

- **Grade 1 Leak** - A leak in which in the judgment of operating personnel at the scene is as an existing or probable hazard to public safety, property, or a significant environmental emission risk or meets the definition of an incident in § 191.3.

  (1) A Grade 1 Leak includes:
  a. A hazardous leak, as defined in § 192.3
  b. Damage by third party resulting in leakage;
  c. Escaping gas that has unintentionally ignited;
  d. Any indication that gas has migrated into a building, under a building, or into a tunnel as indicated using a combustible gas indicator (CGI);
  e. Any reading of gas using a CGI underground within five feet (1.5 meters) of a building wall;
  f. Any reading of 80% or greater of the LEL (60% for LPG systems) using a CGI in an enclosed space or substructure including manholes, vaults, catch basins;

  (2) A Grade 1 leak requires an immediate effort to protect life and property.
  (3) Continuous action[20] shall be thereafter taken until the condition is no longer hazardous.
  (4) Completion of repairs shall be scheduled on a regular day-after-day basis, or the condition kept under daily surveillance until the source of the leak has been corrected.

- **Grade 2 Leak** - A leak that does not meet the Grade 1 criteria but is in the judgment of operating personnel at the scene a probable future hazard to public safety, property, or significant environmental emission risk.

[20] Continuous action includes on-going mitigation measures as defined in an operators O&M plan to minimize public safety and emissions risk.

(1) A Grade 2 Leak includes:

a. Any reading less than 10 percent gas-in-air between the building and the curbline in any area continuously paved which is more than five feet (1.5 meters) but within 30 feet (9.1 meters) of the building and inside the curbline or shoulder of the road; or
b. Any reading less than 20 percent gas-in-air in any unpaved area which is more than five feet (1.5 meters) from but within 20 feet (6.1 meters) of a building and inside the curbline or shoulder of the road; or
c. Any reading of 30 percent or greater gas-in-air in an unpaved area which is more than 20 feet (6.1 meters) from but within 50 feet (15.2 meters) of a building and inside the curbline or shoulder of the road; or
d. Any reading of 30 percent or greater gas-in-air in a paved area which is more than 30 feet (9.1 meters) from but within 50 feet (15.2 meters) of a building and inside the curbline or shoulder of the road; or
e. Any reading above one percent but below four percent gas-in-air, within manholes, vaults or catch basins (sampling will be conducted with the structure in its normal condition as nearly as is physically possible).

(2) Grade 2 leaks shall be repaired within a period not to exceed one year.
(3) Grade 2 leaks shall be maintained under surveillance with a frequency not to exceed two months, except that leaks classified under paragraph (e) above shall be surveilled every two weeks unless extreme weather conditions warrant additional surveys as defined in an operator’s integrity management and/or O&M plan.

- **Grade 3 Leak** – Any leak that does not meet the grade 1 or 2 criteria. Grade 3 Leaks shall be further characterized as an actionable emissions risk if:

(1) Is of sufficient magnitude to pose a significant emissions risk to the environment, applying one of the following criteria as determined by the operator:

(i) estimated leakage rate of 10 cubic feet per hour (CFH) or more; or
(ii) estimated ‘‘leak extent’’ (land area affected by gas migration) of 2,000 square feet or greater; or
(iii) an alternative method for determining environmental significance (such as the sum of bar hole leak indication readings % gas-in-air using a CGI) as identified in an operators’ integrity management and/or O&M plan.

Leak Repair Requirements – Consideration of an Emissions Risk-Based Approach to Addressing Nonhazardous Grade 3 Leaks

Utility commissions across the country have reviewed and continue to review infrastructure modernization programs to replace aging natural gas delivery infrastructure.

In certain states, the programs are a result of regulatory filings, whereas in others, modernization and replacement policies were developed pursuant to legislative action[21].

The goal of each of these programs is the same: to ensure that the infrastructure upgrades and/or replacements necessary for the safe, efficient, reliable, and environmentally responsible delivery of natural gas are completed. There is no definitive best regulatory approach to addressing infrastructure replacement and modernization. In considering local distribution company (LDC) proposals to improve and replace infrastructure, commission's take into consideration the age of the infrastructure, factors affecting the ability of the LDCs to recover associated costs (e.g., changes to customer rates or bills in the broader context of socio-economic conditions), reliability, safety, environmental benefits, and the interests of the consumers themselves, including for rate continuity.

While Grade 3 leaks are recognized as nonhazardous to persons or property at the time of detection and can reasonably be expected to remain nonhazardous, NGA also recognizes the emissions risk component of Grade 3 Leaks. Grade 3 leaks are generally associated with legacy materials of construction (leak prone pipe (LPP) and are addressed within state approved infrastructure replacement programs. These programs are underpinned by risk-based assessments that take a balanced approach to prioritizing pipe segment replacement to extract the greatest degree of safety value including emissions reductions. The effectiveness of this balanced approach to managing emissions risk as a component of DIMP is evidenced by the fact methane emissions from natural gas distribution systems across the country have declined by 70 percent from 1990 – 2021[22] however NGA also recognizes there is more to do.

NGA is proposing a practical, fit-for-purpose alternative approach to further addressing Grade 3 Leak mitigation and enhancements to DIMP risk-based pipe replacement algorithms which includes assessing and addressing emissions risk in the spirit of the Pipes Act by assessing and implementing mitigation options for *actionable emitters*. Indeed, some states have already mandated a similar approach to address emissions risk on an otherwise nonhazardous leak awaiting mitigation through infrastructure replacement programs[23]. Each operator would be required to revise their DIMP and include assessment of Grade 3 actionable emitters and associated mitigation criteria. Proposed mitigation criteria for Grade 3 Leaks includes:

[21] National Association of Regulatory Utility Commissioners (NARUC) Report January 2020
[22] *See* 2023 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2020 (April 15, 2023) (2022 GHGI).
[23] 220 CMR 114 Massachusetts Department of Public Utilities

(1) A Grade 3 Leak must be repaired within 5 years of the date of discovery except as described below:
  (i) A Grade 3 Leak actionable emissions risk shall be repaired within 24 months.
  (ii) A Grade 3 Leak non-actionable emissions risk on a leak prone pipe segment must be repaired or the pipe segment replaced within 10 years provided the leak is evaluated in accordance with (2) below.
(2) An operator must re-evaluate each Grade 3 leak at least once every 12 months not to exceed 15 months until the repair of the leak is complete.

Extension of Leak Repair/Remediation Grade 2 and Grade 3 Leaks

NGA supports a provision that allows an operator to 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 or in the case of an intrastate pipeline facility regulated by the State, the appropriate State agency.

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.

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 or required to comply with from a state jurisdictional perspective. Once the rule is finalized, operators will need sufficient time to re-evaluate their existing leaks and determine if any changes in classification are necessary.

In addition, a management of change plan must be developed to ensure sustainable compliance conformance including addressing analysis of new federal requirements relative to state jurisdictional requirements, adjust operating procedures, assess impacts to contractual requirements and labor agreements, assess and update training and operator Qualification (OQ) requirements. 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. No less than 36 months are required from the time of the Final Rule’s effective date to ensure that existing leaks are re-graded appropriately, and management of change plans are appropriately implemented. procedures and training are administered adequately.

By allowing operators the necessary time to reassess their existing leaks and management of change plans, 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.

Impacts of Accelerated Leak Repair Timelines on Pipe Replacement Programs & Maximizing Public Safety Value

Expedited leak repair requirements are likely to have unintended deleterious effects to operators’ long-term pipeline replacement and infrastructure modernization initiatives. Pipeline replacement programs span several years and typically require submittal to, and approval from, state regulatory bodies, 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 proposed accelerated leak repair requirements compel operators to allocate funds and resources toward fixing leaks in pipelines that are (or may soon be) scheduled for replacement as part of a strategic pipeline replacement project. Repairing these leaks slightly sooner diverts resources from planned infrastructure upgrades, wastes resources, and hinders operators’ ability to execute strategic replacement plans effectively. Like pipeline replacement, leak repair work has an impact on the individuals living near the pipelines. Crews fixing leaks utilize equipment that impact road travel, emit 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 impact operators' 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 re-grading and repair activities with compressed timelines. The rule, as proposed, will incentivize operators to move towards more reactive leak mitigation and away from proactive replacement programs.

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. NGA supports PHMSA's proposal concept to provide an exception to Grade 3 leak repair timelines if the segment containing the leak is scheduled for replacement and is replaced (§ 192.760(d)(2)(ii)). This concept 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 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 the 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 clear 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 stringent requirements in this NPRM to re-evaluate Grade 2 leaks on a periodic basis.

Leakage Survey Frequencies – Consideration of a Risk-Based Frequency of Inspection

A fundamental premise of risk management is reallocation of resources from activities that have a lesser effect on risk to activities that can have a greater impact. The current intervals specified for required inspections in Part 192 are not risk based and the proposal as written further propagates this non-risk-based approach to regulation.

The industries approach and understanding of risk-based inspection frequencies has advanced significantly with the introduction of sound engineering practices prescribed in the American Petroleum Institute Recommended Practice RP 580[24] for assessing Risk Based Inspections.

§192.723 for gas distribution operators requires leakage surveys be performed every 5-years not to exceed 63 months in non-business districts. 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 nine gas distribution pipeline operators, the Associations in their comments 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, NGA, believes the proposed amendments in the 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, more risk-based approach (e.g., DIMP and applying fundamental principles in API 580), since operators know their system, geography, conditions, and operational idiosyncrasies. Frequency of leakage surveys can be (and often are) accelerated by operators based on risk and performance of their systems. The successful utilization of DIMP to appropriately increase leak surveys based upon risk is discussed in further detail in these comments.

In addition, the current 5-year frequency facilitates synchronization of other pipeline safety risk assessments such as atmospheric corrosion inspections which was recently updated, appropriately, to a 5-year frequency based on overwhelming risk-based inspection evidence. Yet another factor to consider in assessing a risk-based approach to frequency of inspection is the introduction, and operators advocating use, of residential methane detectors. Literally hundreds of thousands of these devices have been installed in New York State alone supported by gas safety regulators and policymakers with hundreds of thousands more planned throughout the state. This is another example of a “layers of protection” approach to maximizing public safety value that needs to be integrated into the overall risk assessment when considering leak survey inspection frequencies.

---

[24] American Petroleum Institute API Recommended Practice (RP) 580-2016 Risk-based Inspection (RBI), 3rd edition, February 2016

3.2 Advance Leak Detection Programs

NGA supports codification of minimum performance capabilities of instruments and technologies for leakage surveys as part of an advanced leak detection program. This approach will help support a fit-for-purpose use of technologies and practices that ensure leakage surveys and other leak detection practices are performed with fit-for-purpose equipment, procedures, and competent personnel. NGA also supports 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. NGA believes simply 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 *good science common sense approach* used in conducting leak surveys and other O&M related leak detection activities. NGA also believes that in assessing and repairing leaks that PHMSA considers the overall carbon footprint of mitigation strategies and potential impact on ratepayers and overall pipeline safety value.

However, NGA remains 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 and fit-for-purpose, 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 more traditional, yet state-of-the-art equipment with 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.

NGA is also concerned regarding the apparent presumption that all leak detection processes and activities are similar in nature regardless of origin. Investigative techniques vary depending on the specific leak assessment activity being performed. For example, conducting leak surveys for interior jurisdictional piping versus exterior subsurface piping may require different instrument sensitivity capabilities, measurement techniques and investigative procedures. It is critical that the appropriate instruments, investigative procedures, training, and qualifications are fit-for-purpose considering the variables in performing these functionally specific activities. Instruments for leak surveys versus other leak detection activities may incorporate different sensor technologies and detection thresholds depending on the application of the equipment and site-specific conditions. The most sensitive technologies are used for leak surveys of buried outdoor piping. Low sensitivity thresholds (ppmv) are required to compensate for a variety of environmental variables resulting in diluted gas concentrations outdoors and/or reaction with the soil and other subsurface variables affecting gas migration patterns. In contrast, other O&M related leak detection activities, beyond mandated regulatory leak surveys, may incorporate instruments, equipment and procedures that are fit-for-purpose as identified in an operators O&M manual.

As a result, the sensitivity capability for performing these functions is typically effective in the % LEL range. An example of fit-for-purpose detection threshold application in the % LEL range are instruments and investigative techniques for conducting indoor jurisdictional piping leak surveys, where the survey environment is not affected by variables such as wind/soil diffusion and gas migration patterns.

While it may seem counter intuitive, if the instrument threshold detection limit is not aligned for the leak detection activity being performed, it may impede leak detection in the presence of a background combustible gas concentration at the parts per million level. The device may trigger a false alarm when the conditions are only slightly above background. Using leak survey equipment with a 5 ppm detection threshold for indoor piping may hinder an effective and efficient leak survey process.

One margin of safety calculation is a measurement of the difference between an instrument's detection threshold, and the Lower Explosive Limit (LEL) of methane in air (5% methane in air). If a combustible gas indicator ("CGI") threshold detection value is 0.1% gas in air (one part per thousand), the difference between the threshold detection limit and the LEL value is 50 times. The margins of safety for engineering design range from 1.5 to 20 times, depending on the application. The 50 times margin of safety is at least 2½ times greater. Instrument sensitivity requirements should consider a fit-for-service approach which includes allowing use of conventional CGI's and other methods such as the soap bubble test for conducting O&M related leak detection activities and interior and exterior above ground exposed piping leak and surveys. The current proposal would have significant unintended consequences of having to potentially replace tens of thousands of fit-for-purpose CGI instruments with little or no public safety value.

A comprehensive White Paper developed by GTI Energy is included as part of this submittal in Appendix B which highlights a fit-for-purpose approach not applying leak detection technology solutions. This White Paper served as a reference tool when New York State was developing a technology approval approach for instruments utilized in meeting regulatory requirements associated with gas leak detection[25].

In addition, some operators are currently deploying advanced fixed-sensor technologies integrated with smart metering systems that can provide continuous monitoring surveys of interior building jurisdictional piping. These devices/systems can monitor for leaks on interior building jurisdictional piping and if strategically placed, also monitor the potential for gas migration into a building from subsurface exterior jurisdictional piping through penetrations in basement walls.

[25] Appendix B - Leak Survey Equipment Considerations for NY Operations Development of a Regulatory Conformance and Technology Applicability White Paper, Gas Technology Institute, May 12, 2016,

These devices and systems are designed and installed to current industry standards specified by the National Fire Protection Agency[26] and Underwriters Laboratory Standards for Safety[27] 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).

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 Integrity Management and O&M plans.

NGA's commitment to exploring fit-for-service applications of ALDP is demonstrated by recent work of its research & development organization, NYSEARCH. 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 Advanced Mobile Leak Detection ("AMLD") technologies (including two types of cavity ring down spectrometers technologies[28] (one of which was used in the Weller Study coupled with modeling) with direct measurements of over 300 leaks using a high-volume sampler[29]. The goal of the NYSEARCH Study, co-funded by PHMSA, "was to define a process for independent validation of mobile methane emissions measurement technologies."[30] The results showed AMLD – could quantify leaks within very broad ranges, which is useful as a general tool for prioritizing leak mitigation, 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 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."[31]

Stated simply, the NYSEARCH Study demonstrates that the 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.

---

[26] National Fire Protection Agency, NFPA 715 Installation of Fuel Gases Detection and Warning Equipment

[27] Underwriters Laboratories, UL 1484 Standard for Residential Gas Detectors and UL 2075 Standard for Gas and Vapor Detectors and Sensors.

[28] 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

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

[30] Id. p. 2.

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

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 AMDL can be useful in quantifying overall system emissions.

Instrument Sensitivity

Minimum sensitivity of leak survey equipment is specified in § 192.763(a)(1)(ii) as 5 parts per million (ppm) for each gas being surveyed.[32] 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. 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 indicating that PHMSA has tested or otherwise verified these claims in order to establish a 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 a basis for the proposed minimum sensitivity criteria.

Inconsistency with EPA Requirements

The 5 ppm sensitivity that PHMSA has proposed is inconsistent with prescribed EPA requirements and state jurisdictional regulatory 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 for instrument LDAR monitoring.[33] Leaks from equipment within process units at onshore natural gas process plants are defined differently and range from 500 to 10,000 ppm.[34]

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.[35] PHMSA provided no technical basis for the 0.01% threshold and is not clear why PHMSA chose the threshold.

---

[32] 88 Fed. Reg. at 31,932.
[33] 40 CFR § 60.5397a(a)(1).
[34] 40 CFR §§ 60.482-2a-60.482-11a.
[35] 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.

Congress directed PHMSA "to conduct leak detection and repair programs . . . to protect the environment."[36] 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 the statutory mandate and would impose significant burdens on pipeline operators with little to no associated environmental or pipeline safety benefit.

False Positives May Result from Inappropriate Sensitivity Requirements

When selecting a performance standard for leak survey of transmission pipelines, the agency should account for the fact that too restrictive of a performance standard may 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. As reported in the Association's comments, an interstate pipeline operator deployed the 5 ppm sensitivity level for leak survey of certain areas of its 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 leak 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 and may even be detrimental.

Use of EPA-Approved Methods for Above-Ground Sources

EPA and state programs have robust requirements to regulate methane leaks on equipment in areas within the fence line of a facility. 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."[37] PHMSA also confirms that "OGI cameras…are commonly used for fugitive emissions monitoring at LNG plants, compressor stations, and other facilities."[38] 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.[39] 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, NGA supports the Associations proposal incorporating fit-for-purpose detection threshold criteria for mandated regulatory leak surveys that considers variables associated with leak detection equipment applications such as buried piping, exposed piping, piping exposed within buildings or structures etc. in § 192.763:

---

[36] 49 U.S.C. § 60102(q)(1)(B).
[37] 88 Fed. Reg, at 31,932.
[38] 88 Fed. Reg, at 31,933.
[39] Proposed Section 192.763(a)(1)(iii)(A)-C).

§ 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 identify operator approved leak detection equipment used to perform leakage surveys and other leak detection activities.
(ii) Leak detection equipment used in conducting leakage surveys must have a minimum sensitivity capability of one of the following:

(A) 5 parts per million for each gas being leakage surveyed using handheld or mobile leak detection survey equipment for leakage surveys of subsurface piping and piping components, 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 or investigated using optical, infrared, or laser-based leak detection equipment; mobile, aerial, or satellite-based platforms; or using fixed continuous monitoring sensors for jurisdictional piping within buildings;
(C) 500 parts per million for handheld leak detection equipment used within buildings; or
(D) sensitivity otherwise meeting the requirements of 40 C.F.R. Part 60, subpart OOOO for optical gas imaging or equivalent.

The operator must validate the sensitivity of this equipment periodically in accordance with manufacturer's instructions.

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[40] – against which all leak detection equipment must be evaluated for acceptability.

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

However, defining such a “universal leak” by gas concentration *and* distance alone fails to consider other critical real-world leak characteristics, such as soil conditions, atmospheric conditions, plume behavior, and margin of uncertainty in the equipment being used. Even if operators attempted to apply this proposed standard within a controlled environment, it could not be practically or consistently 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 more than 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.

3.3 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 provide clarity and flexibility necessary to create and implement a technically feasible, fit-for-purpose 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 ensure that the equipment, practices, frequencies, and program evaluations of ALDP will address both public safety and environmental protection effectively.

3.4 Liquefied Natural Gas Facilities—§ 193.2624

Liquefied natural gas facility operations play a vital role in providing energy supply security in the northeast region. Collectively, NGA members own/operate the largest number of LNG peakshaving facilities in the country and as such may have significant impacts by the proposed additional monitoring requirements.
It is important to distinguish these facility operations from larger import/export terminal operations as they have a different potential emissions profile, however far too often these facilities are inappropriately aggregated for purposes of emissions assessments.
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. If an LNG facility is already subject to LDAR requirements that provide adequate protection to public safety and the environment, there is no reason for PHMSA to add duplicative, and potentially inconsistent, regulations on that same topic in Part 193. PHMSA should also consider the unique nature of operations of peak shaving facilities when considering this proposal including emissions and public safety risk.

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.[41]

[41] 49 C.F.R. § 193.2019(a) (stating, in relevant part, that "mobile and temporary LNG facilities for peakshaving 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")

- 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 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, 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, another federal or state agency, or authority having jurisdiction (“AHJ”); or

(2) A mobile or temporary LNG facility.

Respectfully submitted,

Jose Costa

By: Jose Costa
President & CEO
Northeast Gas Association
1800 West Park Drive,
Ste 340, Westborough, MA, 01581
jcosta@northeastgas.org

For further information please contact:

Paul Armstrong
Vice President of Operations
Northeast Gas Association
(781) 455-6800 ext. 1130
parmstrong@northeastgas.org

or

Robert Wilson
Vice President Special Projects
Northeast Gas Association
(607) 643-5111
bwilson@northeastgas.org

APPENDIX

Appendix A - Final Report GTI Project Number 22509-3, 2019 Emission Factor Pilot Study, August 2020

Appendix B - Leak Survey Equipment Considerations for NY Operations Development of a Regulatory Conformance and Technology Applicability White Paper, Gas Technology Institute, May 12, 2016,