PHMSA issued this Final Rule on January 17, 2025, and it has been submitted to the Office of the Federal Register for publication. Although PHMSA has taken steps to ensure the accuracy of this version of the Final Rule posted on the PHMSA website, and will post it in the docket (PHMSA-2021-0039) on the Regulations.gov website (www.regulations.gov), it is not the official version. Please refer to the official version in a forthcoming Federal Register publication, which will appear on the websites of each of the Federal Register (www.federalregister.gov) and the Government Publishing Office (www.govinfo.gov). After publication in the Federal Register, this unofficial version will be removed from PHMSA's website and replaced with a link to the official version. PHMSA will also post the official version in the docket.

Billing Code: 4910-60-W

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Parts 191, 192, and 193

[Docket No. PHMSA-2021-0039; Amdt. Nos. 191-33, 192-138, 193-26]

RIN 2137-AF51

Pipeline Safety: Gas Pipeline Leak Detection and Repair

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), Department of Transportation (DOT).

ACTION: Final rule.

SUMMARY: PHMSA is amending the Federal pipeline safety regulations to implement congressional mandates in the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 to enhance pipeline safety and reduce methane emissions from new and existing gas transmission pipelines; gas distribution pipelines; regulated Types A, B, C, R, and offshore gas gathering pipelines; underground natural gas storage facilities; and liquefied natural gas facilities. Among the amendments for part 192-regulated 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 mitigating emissions from blowdowns; pressure relief device design, configuration, and maintenance requirements; and clarified requirements for investigating failures. PHMSA is also expanding reporting requirements for operators of all gas pipeline facilities within the U.S.

DOT's jurisdiction, including underground natural gas storage facilities and liquefied natural gas facilities.

DATES: This final rule is effective **[INSERT DATE 180 DAYS AFTER THE DATE OF PUBLICATION IN THE FEDERAL REGISTER]**.

FOR FURTHER INFORMATION CONTACT: Sayler Palabrica, Transportation Specialist, by telephone at 202-744-0825 or by email at sayler.palabrica@dot.gov.

SUPPLEMENTARY INFORMATION:

I. Executive Summary

A. Purpose of Regulatory Action

This final rule amends the Federal pipeline safety regulations (49 CFR parts 190 through 199; PSR) considering the proposals in a Notice of Proposed Rulemaking (NPRM) titled "Pipeline Safety: Gas Pipeline Leak Detection and Repair," which was published on May 18, 2023,[1] in response to bipartisan congressional mandates in the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (PIPES Act of 2020, Pub. L. 116-260) The amendments of this final rule will enhance pipeline safety and reduce both "fugitive emissions" (emissions resulting from leaks and equipment failures, also called "unintentional leaks" or "unintentional emissions") and "vented emissions" (emissions resulting from blowdowns, equipment design features, and other intentional releases, also called "intentional emissions")

[1] 88 FR 31890 (May 18, 2023).

from over 3.3 million miles of gas transmission, distribution, and gathering pipeline facilities, 398 underground natural gas storage facilities (UNGSF), and 173 liquefied natural gas (LNG) facilities, thereby improving public health and safety, promoting environmental justice, and addressing the climate crisis.

Consistent with the mandates from the PIPES Act of 2020, this final rule addresses shortcomings in the PSR regarding leak detection and repair (LDAR) on gas transmission, distribution, and regulated gathering pipelines, UNGSFs, and LNG facilities. The amendments in this final rule are designed to help ensure that the PSR provide for gas pipeline safety, protect the environment, and reflect the capabilities of commercially available leak detection technologies. The LDAR requirements in this final rule help ensure the timely identification and repair of leaks that could otherwise degrade into catastrophic failures and incidents that threaten public safety. In recognition of the importance given to environmental protection in PHMSA's enabling statutes,[2] this final rule also addresses the scientific consensus that prompt reductions in methane emissions from natural gas infrastructure are critical to limit the impacts of climate change. The supporting regulatory impact analysis (RIA) for this rulemaking considers both the safety benefits and the environmental benefits in accordance with section 118 of the PIPES Act of 2020. Likewise, the final Environmental Assessment (EA) for this rulemaking evaluates the environmental impacts of the final rule in accordance with the National Environmental Policy Act (NEPA). This final rule will have a positive effect on the environment by reducing the occurrence, magnitude, and consequences of gas releases and associated methane emissions from

[2] 49 U.S.C. 60102(b)(1)(B)(ii), 60102(b)(2)(A)(iii), 60102(b)(5), 60102(q)(1)(B), 60102(q)(2)(B)(i).

pipeline facilities. Environmental concerns that were raised in public comments to this rulemaking are addressed in the EA for this rulemaking.

The Federal LDAR standards for gas pipeline facilities have remained largely unchanged since the 1970s despite significant improvements in leak detection technology and operator practices and the increasingly urgent and tangible threats from climate change. Until now, the PSR did not include any meaningful performance standards for leak detection equipment, nor did the regulations leverage any of the significant advancements in the sensitivity, efficiency, and variety of leak detection technologies achieved over the last five decades. The PSR did not explicitly require repair of all—or even most—leaks on gas pipeline facilities. If an operator determined that a leak did not present an existing or probable public safety hazard, that leak did not need to be repaired at all, regardless of the environmental harms that would result. Prior regulations also did not prescribe specific timeframes for the repair of hazardous or other leaks, with the narrow exception of those leaks associated with certain metal loss, crack, and dent defects discovered on gas transmission pipelines during integrity assessments operators perform in accordance with subpart O of 49 CFR part 192 or § 192.714. Additionally, the current PSR tolerate significant intentional emissions of methane and other gases, even in non-emergency situations, by allowing venting, blowdowns, and other large-volume releases of gas from all PHMSA-jurisdictional pipeline facilities without restriction, potentially conflicting with a new self-executing section of the PIPES Act of 2020 as described below. PHMSA's minimum incident reporting threshold was established principally to reflect the economic consequence of lost gas[3] and was set at 3 million standard cubic feet (MMCF), leaving many large-volume gas releases unreported. This further demonstrates the PSR's historical lack of emphasis on the environmental consequences of gas releases. Prior to this rulemaking, PHMSA had no reporting requirements for intentional releases of gas.

Congress targeted these regulatory shortcomings in the bipartisan PIPES Act of 2020. Section 113 of the PIPES Act of 2020 mandated that PHMSA establish performance standards for LDAR programs for certain part 192-regulated[4] gas gathering, transmission, and distribution pipelines that reflect the capabilities of commercially available advanced technology and practices for the identification, location, categorization, and repair of all leaks that are hazardous to public safety or the environment, or that pose a potential hazard. Section 114, moreover, requires operators of all pipeline facilities to update maintenance and inspection procedures to address the elimination of hazardous leaks and minimization of natural gas releases—whether

[3] Prior to the adoption of the volumetric incident criterion, the cost of lost gas was included in the property damage calculation. In the NPRM that proposed the adoption of a volumetric threshold, PHMSA described both a petition from the Interstate Natural Gas Association of America noting that more incidents were reportable due to changes in the cost of gas, as well as a GAO recommendation (GAO-06-946) to adjust the incident reporting criteria to account for the cost of lost gas. That NPRM did not identify environmental considerations among the motivations for that change in incident reporting requirements. See 74 FR 31675 at p. 31677, "Pipeline Safety: Updates to Pipeline and Liquefied Natural Gas Reporting Requirements" (July 2, 2009).

[4] Throughout this final rule, PHMSA uses the phrase "part 192-regulated gas gathering pipelines" to refer to offshore gas gathering pipelines, as well as Types A, B, and C "regulated onshore gas gathering" pipelines—all of which are subject to certain part 192 requirements under §§ 192.8 and 192.9. Such "part 192-regulated gas gathering pipelines" does not include "reporting-regulated" or "Type R" gas gathering pipelines as defined in §§ 191.3 and 192.8(c)(3), which are not subject to part 192 safety requirements. Similarly, PHMSA also refers to "part 192-regulated gas pipelines" to collectively refer to gas transmission, distribution, offshore gathering, and Types A, B, and C onshore gathering pipelines subject to part 192 requirements. "Gas pipeline facilities" is defined as "a pipeline, a right of way, a facility, a building, or equipment used in transporting gas or treating gas during its transportation"—this broader definition applies to all part-192 regulated gas pipelines, UNGSFs, and part 193-regulated LNG facilities. See 49 U.S.C. 60101(a)(3).

those are fugitive emissions from leaks or intentional releases due to venting from maintenance and other activities—and the replacement or remediation of pipelines known to leak based on the material (including cast iron, unprotected steel, wrought iron, and historic plastics with known issues), design, or past operations and maintenance (O&M) history of the pipeline. Section 118 of the PIPES Act of 2020 clarified that PHMSA must consider both environmental benefits and public safety benefits when proposing or issuing any pipeline safety standard. The mandates in the PIPES Act of 2020 underline the importance of reducing methane emissions from the pipeline systems.

Therefore, this final rule includes several regulatory revisions to improve public safety and minimize emissions of methane and other flammable, toxic, or corrosive gases from new and existing offshore gas gathering pipelines; regulated onshore gas gathering, transmission and distribution pipelines; UNGSFs; and LNG facilities. PHMSA expects that the amendments in this final rule will improve public safety; yield prompt and meaningful reduction of methane emissions, a key contributor to climate change; and mitigate the disproportionate burden of those safety and environmental risks historically placed on minority, low-income, or other underserved and disadvantaged populations that normally live in older communities.

B. Summary of the Regulatory Provisions

This final rule adopts the proposals from the NPRM with several changes made to address the recommendations of the Technical Pipeline Safety Standards Committee, also known as the Gas Pipeline Advisory Committee (GPAC; the Committee),[5] and over 40,000 public comments.[6] Among the most notable changes from the proposed requirements are modifications to the leak detection performance standard to better accommodate commercially available advanced technology used for detecting leaks, improved specificity for grading leaks, and changes to the leak repair timelines and leak survey intervals inside of buildings. These amendments are outlined in the paragraphs below, with further detail provided in sections III and IV. The effective date of this final rule is **[insert date 180 days after date of publication in the Federal Register]**.

First, this final rule increases the leak survey frequencies in § 192.723 for certain distribution pipelines located outside of business districts[7] by requiring annual leak surveys for gas distribution pipelines located outside of buildings and that lack cathodic protection or that are known to leak based on their material, design, or O&M history. This final rule also revises leak surveys requirements in §§ 192.9 and 192.706 for gas transmission, offshore gathering, and Types A, B, and C gathering pipelines in Class 3 locations, Class 4 locations, and high-consequence areas (HCA), with operators performing leak surveys most frequently on pipelines located in HCAs within Class 4 locations. PHMSA has also increased the minimum patrolling

[5] See Section II. F for additional information on the GPAC meetings.

[6] In addition to approximately 35,000 comments submitted to the docket, PHMSA received approximately 8,000 comments via email from a form letter campaign. These comments were consolidated and made available by PHMSA at PHMSA-2021-0039-24331 and by the organizer at PHMSA-2021-0039-25522.

[7] The term "business district" is not defined in part 192. However, in a letter of interpretation PHMSA stated that the term normally refers to an area "associated with the assembly of people in shops, offices and the like," marked by the conduct of "buying and selling commodities and services, and related transactions." See PHMSA, Interpretation Response Letter No. PI-72-038 (Aug. 16, 1972).

frequencies for gas transmission, offshore gathering, and Types A, B, and C gathering pipelines in §§ 192.9 and 192.705.

Second, this final rule introduces an ALDP performance standard in a new § 192.763 that requires operators of 49 CFR part 192-regulated pipelines, other than dedicated hydrogen pipelines, to use commercially available leak detection equipment that meets the ALDP performance standard. This final rule also restricts the sole use of human senses instead of leak detection equipment to only submerged gas transmission and submerged gas gathering pipelines.

Third, this final rule requires operators of gas transmission, distribution, and part 192-regulated gathering pipelines to identify, locate, classify, and repair all leaks in a timely manner, except for those leaks with a leak volume so small as to pose a relatively marginal risk to people, property, and the environment in § 192.703 and a new § 192.760. Before this rule, part 192 provisions governing the repair of leaks were unclear regarding when, if at all, most leaks must be repaired. Although some—not all—part 192-regulated pipelines were subject to a general maintenance requirement at § 192.703(c) to "promptly repair hazardous leaks," the maintenance requirements in part 192 prior to this rulemaking did not define "hazardous leak" in terms of risks to the environment or establish meaningful timelines for the repair of such leaks. This final rule clarifies those requirements and responds to the section 113 mandate of the PIPES Act of 2020 by requiring operators to identify, locate, classify, and repair leaks on an appropriate timeline. This requirement builds on the tiered leak grading and repair criteria framework of the Gas Piping Technology Committee (GPTC) "Guide for Gas Transmission and Distribution

Piping Systems."[8] As such, this final rule requires operators classify every discovered leak as a grade 1, grade 2, or grade 3 leak and prioritize the repair or remediation of those leaks that pose the greatest risks to public safety and the environment.

Fourth, this final rule requires operators to minimize intentional emissions, such as blowdowns, on gas transmission, offshore gathering, Type A gathering pipelines, and LNG facilities in §§ 192.770 and 193.2523. Operators must choose from among proven, cost-effective mitigation measures when performing blowdowns for O&M or construction purposes.

Fifth, this final rule requires operators of gas transmission, distribution, offshore gathering, and Types A, B, and C gathering pipelines to design and configure all new and modified pressure relief and limiting devices to minimize unnecessary releases in § 192.199. Amendments to § 192.739 also require operators to evaluate and remediate any relief devices that operate outside of the tolerances established in the operator's procedures. These requirements will minimize unintended and unnecessary releases of gas to the atmosphere, better protecting against environmental and public safety hazards posed by malfunctioning, poorly designed, or incorrectly configured pressure relief devices.

Sixth, amendments to §§ 192.12, 192.9, 192.605, 193.2503, and 163.2605 codify self-executing mandates from section 114 of the PIPES Act of 2020[9] that require operators of gas

[8] Gas Piping Technology Committee Z380, ANSI GPTC Z380.1-2022, "The Guide for Gas Transmission, Distribution, and Gathering Piping Systems" Including Addenda 1 and 2 (2022).

[9] PHMSA describes certain provisions in Section 114 as "self-executing," meaning those provisions became effective and binding on pipeline operators one year after the date of enactment of the PIPES Act of 2020 without further action by the Department of Transportation. See 49 U.S.C. 60108(a)-(b); PIPES Act of 2020 Section 114(b).

pipeline facilities to have written procedures to eliminate hazardous leaks, minimize releases of natural gas, and remediate or replace pipelines known to leak based on material, design, or past O&M histories.

Seventh, this final rule makes several changes to part 191 reporting requirements and associated forms. The rule requires operators to report large-volume releases of gas, both unintentional releases and, for the first time, intentional releases of 0.5 MMCF of gas or more from any gas pipeline facility over 96 hours. PHMSA has also revised the annual report forms for gas transmission, distribution, offshore gathering, and Types A, B, and C gathering pipelines to collect information regarding the number and grade of all leaks operators identify and repair each calendar year, as well as the estimated emissions from those leaks.

Finally, a new § 193.2624 requires operators of part 193-regulated LNG facilities to perform periodic methane leakage surveys of non-tank equipment and components within LNG facilities using leak detection equipment and minimum leak detection standards consistent with gas transmission pipeline requirements. Operators of LNG facilities must repair any leaks found during such surveys in accordance with their maintenance or abnormal operations procedures. As for other pipeline facilities, PHMSA has modified the annual report form for LNG facilities to include reporting of methane leaks discovered and repaired pursuant to the new § 193.2624.

C. Costs and Benefits

Consistent with Executive Order (E.O.) 12866, as amended by E.O. 14094, and the requirements of the Federal Pipeline Safety Laws,[10] PHMSA has prepared an assessment of the benefits and costs (including commercial benefits, public safety benefits, environmental benefits, and compliance costs, and other risks) of the final rule, as well as reasonable alternatives. PHMSA estimates that emission reductions attributable to this final rule corresponds to approximately 54 percent of unintentional emissions from regulated gathering pipelines, 40 percent of unintentional emissions from transmission pipelines, and 13 to 30 percent of unintentional emissions from distribution pipelines. These estimates are relative to modeled baseline emissions projected over the 15-year period of analysis based on the pipeline mileage, empirical emission factors, and existing operator survey and repair practices. Further, PHMSA estimates that the total avoided blowdown emissions under this final rule corresponds to approximately 43 percent of baseline blowdown emissions. As such, PHMSA estimates that this final rule will result in monetized net benefits between $702 to $1,329 million per year using a 2 percent discount rate. PHMSA also assessed benefits to public safety and some benefits to public health qualitatively and discusses those benefits throughout this final rule and the RIA, which is available in the docket for this rulemaking.

The regulatory amendments in this final rule will improve public safety, reduce threats to the environment (including, but not limited to, reducing methane emissions contributing to

[10] 49 U.S.C. 60101 et seq. (Federal Pipeline Safety Laws). The specific requirements referenced in the above discussion are located at 49 U.S.C. 60102(b).

climate change), and promote environmental justice for minority populations, low-income populations, and other underserved and disadvantaged communities. PHMSA expects that the modifications it has made in this final rule to the NPRM proposals in response to public comments and GPAC recommendations will improve net benefits of this final rule without compromising safety or environmental objectives. This includes accommodating more cost-effective survey methods and providing more opportunities for operators to efficiently combine maintenance activities. Additionally, the reductions in product losses from the implementation of this final rule will result in cost savings for natural gas shippers and consumers and improve the efficiency and reliability of U.S. energy infrastructure. PHMSA has determined that each element of this rulemaking is technically feasible, reasonable, cost-effective, and practicable because the public safety and environmental benefits of the regulatory amendments described in this final rule and its supporting documents justify the associated costs. PHMSA has also determined that this final rule is superior to alternatives considered in the RIA.

II. Background

A. Introduction

This final rule implements mandates from the PIPES Act of 2020 and adopts amendments proposed in the NPRM titled "Pipeline Safety: Gas Pipeline Leak Detection and Repair," which was published on May 18, 2023, with changes made based on recommendations from the GPAC and from the public comments received. The final rule includes amendments applicable to gas distribution lines, gas transmission lines, part 192-regulated gas gathering lines

(Types A, B, C, and offshore gathering lines), Type R reporting-regulated gas gathering lines, UNGSFs, and part 193-regulated LNG facilities.

B. Purpose of the Final Rule

1. PIPES Act of 2020

The PIPES Act of 2020, which was signed into law on December 27, 2020, was written with broad bipartisan congressional support as well as widespread industry and stakeholder support and directed a fundamental shift in PHMSA's regulation of gas pipeline facilities to consider both environmental benefits and public safety when deciding what and how to regulate pipelines.[11] Concerned in particular with the impact of methane releases from natural gas pipelines on climate change,[12] Congress included within that legislation three sections that will be implemented through this final rule: sections 113, 114, and 118.

Section 113 of the PIPES Act of 2020 requires the Secretary of Transportation to issue regulations requiring operators of gas transmission pipeline facilities, distribution pipeline facilities, and certain regulated gathering pipelines in Class 2, Class 3, and Class 4[13] locations to conduct LDAR programs to meet the need for gas pipeline safety and to protect the environment. Per the mandate, such regulations must include minimum performance standards that reflect the

[11] See 49 U.S.C. 60102(b)(5).
[12] *See, e.g.*, 166 Cong. Rec. H7305 (Dec. 21, 2020) (memorializing a statement by Rep. Pallone that "[t]his is a big win in the fight against climate change, along with the reauthorization of the Pipeline Safety Act, which reduces methane leaks."); "Press Release from Senate Commerce Committee Leaders Commending Passage of Pipeline Safety Legislation" (Dec. 22, 2020), https://www.commerce.senate.gov/2020/12/committee-leaders-commend-passage-of-pipeline-safety-legislation (quoting Sen. Cantwell as stating "This legislation also ensures that the latest technology will be used to detect and prevent costly methane leaks, which is especially important because methane leaks are a significant hazard and a major contributor to global warming.").
[13] Class locations are defined at § 192.5.

capabilities of commercially available advanced leak detection (ALD) technologies that are appropriate for the type of pipeline, location, material of construction, and the product transported. These LDAR programs must be able to identify, locate, and categorize all leaks that are hazardous to human safety or the environment or have the potential to become explosive or otherwise hazardous to human safety. In accordance with the mandate, the regulations must require operators use ALD technologies and practices through continuous monitoring on or along the pipeline, periodic surveys with handheld equipment, equipment mounted on mobile platforms, or other commercially available technology. The regulations must also identify any scenario where operators may use leak detection practices dependent on human senses and include a schedule for repairing or replacing each leaking pipe, except for a pipe with a leak so small that it poses no potential hazard. Congress also expressly barred the Secretary from reducing the frequency of surveys or extending the duration of leak repair and remediation timelines.

Section 114 of the PIPES Act of 2020 adjusted the requirements for pipeline facility operator inspection and maintenance plans. This self-executing provision of the statute applies to Types A, B, and C gas gathering lines, offshore gas gathering lines, distribution lines, transmission lines, UNGSFs, and part 193-regulated LNG facilities,[14] and it required pipeline operators to update their inspection and maintenance plans to eliminate hazardous leaks and minimize releases of natural gas from pipeline facilities; protect the environment; and replace or

[14] 49 U.S.C. 60108, as amended by § 114 of the PIPES Act of 2020, also applies to hazardous liquid lines regulated under part 195. Codification of the statutory inspection and maintenance procedure requirements for hazardous liquid pipelines are outside the scope of this final rule.

remediate pipelines (including cast-iron, bare-steel, unprotected steel, wrought-iron, and certain plastic pipelines) that are known to leak based on material, design, or past O&M history. Operators had until December 27, 2021, to update their inspection and maintenance plans to address this self-executing mandate.[15]

Lastly, section 118 of the PIPES Act of 2020 amended the criteria set forth at 49 U.S.C. 60102(b)(5), requiring PHMSA to consider environmental benefits with other anticipated benefits (e.g., public safety) when issuing rulemakings. That statutory amendment reinforced the environmental protection purpose of section 113 of the PIPES Act of 2020 as well as historical provisions (e.g., 49 U.S.C. 60102(b)(1)(B)(ii) and 49 U.S.C. 60102(b)(2)(A)(3)) within the Federal Pipeline Safety Laws that authorize PHMSA to issue regulations acknowledging the environmental protection benefits from regulating gas pipeline facilities.

Gas pipeline operators and related industry trade associations applauded the passage and enactment of the PIPES Act of 2020 as part of the Consolidated Appropriations Act of 2021 (Pub. L. 116-260). For example, the American Petroleum Institute (API) released a statement in support of the Senate's passage of the legislation (S.2299), stating that the "PIPES Act takes

[15] Section 114 also requires the Government Accountability Office to conduct a study to evaluate the procedures used by PHMSA and States when evaluating operators' inspection and maintenance plans, and subsequently issue a report regarding the findings of the study and recommendations for how to further minimize releases of natural gas from pipeline facilities without compromising pipeline safety. Additionally, the Secretary is to, not later than 18 months after the enactment of the PIPES Act of 2020, submit to Congress a report discussing the best available technologies or practices to prevent or minimize the release of natural gas, without compromising pipeline safety, when making planned repairs, replacements, or maintenance to a pipeline facility; or when intentionally venting or releasing natural gas, including when blowing down pipelines. The report must also discuss whether pipeline facilities can be designed, without compromising pipeline safety, to mitigate the need to intentionally vent natural gas.

important steps to make pipelines safer for surrounding communities and the environment."[16] Following enactment, the Interstate Natural Gas Association of America (INGAA) described the PIPES Act of 2020 as a "historic piece of legislation" that "enhances pipeline safety, embraces the latest technologies, and aids in the further reduction of methane emissions."[17] At PHMSA's virtual public meeting held on May 5-6, 2021 (2021 Public Meeting),[18] to discuss advanced methane leak detection technology and practices, the American Gas Association (AGA) and others[19] expressed support for the PIPES Act of 2020 and initiatives that protect the public and the environment, noting that their members have committed to a range of initiatives to reduce methane emissions to achieve goals for addressing climate change.[20]

In addition to satisfying congressional mandates from the PIPES Act of 2020, the rulemaking will lead to substantial climate benefits. Methane is a potent greenhouse gas, and leaks and other releases of methane from gas pipeline facilities contribute to climate change. Eliminating leaks and minimizing releases of natural gas plays an important role in U.S. efforts

[16] API, Press Release, "API Statement of Senate Passage of PIPES Act" (Aug. 6, 2020), https://www.api.org/news-policy-and-issues/news/2020/08/06/api-statement-on-senate-passage-of-pipes-act.

[17] INGAA, Press Release, "INGAA Hails Passage of Historic Pipeline Safety Reauthorization Bill in 2021 Omnibus Package" (Dec. 21, 2020), https://www.ingaa.org/News/PressReleases/38353.aspx (quoting President and CEO of INGAA, Amy Andryszak, praising Congress's direction to PHMSA to update its regulations "to reflect the latest technologies and practices [to] . . . both enhance safety and benefit the environment").

[18] Discussed further in section III.E.1.

[19] The American Gas Association (AGA), API, American Public Gas Association, GPA Midstream Association (GPA), and INGAA submitted joint comments (Doc. No. PHMSA-2021-0039-0008) to the rulemaking docket after the 2021 Public Meeting. Throughout this final rule, references to "AGA et al." refer to those joint comments.

[20] Sames, Cristina. Pipeline Leak Detection, Leak Repair, and Methane Emissions. AGA. May 5, 2021. Briefing materials, recordings, and transcripts of the 2021 Public Meeting are available on the webpage for the meeting at https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=152.

to reduce greenhouse gas emissions and therefore minimize climate-related hazards to people, property, and the environment.

2. Methane Emissions and Climate Change

In section II of the NPRM, PHMSA described in detail the causes and environmental consequences of climate change, the demonstrated contribution of methane emissions to climate change, and the need for PHMSA to update the PSR to protect the environment from the impacts of climate change.

The primary component of natural gas is methane (CH_4). Methane is a greenhouse gas (GHG), which means that its concentration in the atmosphere affects the temperature and climate of the Earth by trapping heat in the atmosphere. Methane is released from both natural and human-caused sources, the latter of which includes leaks and other releases from natural gas pipeline systems. After carbon dioxide (CO_2), methane is the second-most abundant human-caused GHG in the Earth's atmosphere by concentration and accounts for the second-greatest contribution to total radiative forcing (warming effect).[21] The U.S. Environmental Protection Agency (EPA) calculated that methane made up approximately 11.1 percent (by equivalent mass of carbon dioxide) of the annual GHG emissions in 2022 within the United States, whereas carbon dioxide made up 79.7 percent of the total GHG emissions over the same period.[22] According to the 2021 installment of the Sixth Assessment Report (2021 IPCC Report) from

[21] National Oceanic and Atmospheric Administration (NOAA), "Annual Greenhouse Gas Index" at Figure 3 & Table 2 (Spring 2023), https://gml.noaa.gov/aggi/aggi.html.

[22] EPA (2024). Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2022 U.S. Environmental Protection Agency, EPA 430-D-24-001. https://www.epa.gov/ghgemissions/draft-inventory-us-greenhouse-gas-emissions-and-sinks-1990-2022. Pg. ES-8, Figure ES-4

Working Group I of the Intergovernmental Panel on Climate Change (IPCC), the atmospheric concentration of methane gas was measured at 1.866 parts per million (ppm) compared to 410 ppm of carbon dioxide.[23] The IPCC continues to reference the figures from the 2021 IPCC report in the Climate Change 2023 Synthesis Report (2023 IPCC Report).[24]

Due to the physical properties of methane gas, this comparatively small concentration of methane in the atmosphere makes an outsized impact on climate change, and as a result, efforts to reduce methane emissions have an outsized impact on climate change mitigation. The 2021 IPCC Report notes that human-caused methane emissions account for approximately one-third of warming of global average surface temperatures attributed to well-mixed GHG[25] emissions since 1850.[26] The IPCC also noted that in 2019, atmospheric methane concentrations were higher than at any time in 800,000 years, and "strong, rapid and sustained reductions in CH_4 emissions" would be needed to offset short-term warming effects.[27] Once emitted into the atmosphere, some GHGs can persist in the atmosphere for a long time. Carbon dioxide remains in the atmosphere for 300 to 1000 years.[28] Methane lasts in the atmosphere for approximately 12 years once

[23] IPCC, Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change, Summary for Policymakers (SPM)-5 (2021). In the 2021 IPCC Report, atmospheric concentration of CH_4 since 1984 (1980 for CO_2) is based on merging observed gas concentration in the lower troposphere from the NOAA Global Monitoring Laboratory and the Advanced Global Atmospheric Gases Experiment monitoring networks. Emissions in 1850 and earlier are estimated based on assessments of multiple ice cores. 2021 IPCC Report, Table 2.2 and Table AIII.1a.

[24] IPCC, Climate Change 2023: Synthesis Report. Summary for Policymakers (SPM)-4 (2023).

[25] According to the IPCC, well-mixed GHGs include CO_2, N_2O, and CH_4. 2021 IPCC Report, 2.2. These gases "generally have lifetimes of more than several years" and therefore are relatively uniformly distributed within the troposphere (lower atmosphere). 2021 IPCC Report, 2.2.3.

[26] 2021 IPCC Report, SPM-8.

[27] 2021 IPCC Report, SPM-9, SPM-36.

[28] Buis, Alan "The Atmosphere: Getting a Handle on Carbon Dioxide" (Oct. 9, 2019).

released; however, it traps approximately 25 times more energy than an equivalent mass of CO_2 over a 100-year period.[29] Because methane is a more potent, but more short-lived, GHG, reducing methane emissions would have a more rapid and significant effect on reducing the heat-trapping potential of the atmosphere than an equivalent reduction in CO_2 and would therefore result in a greater effect on climate change mitigation in the short term.[30]

Scientific projections underscore the need for achieving a prompt reduction in methane emissions. The 2021 IPCC Report concluded that urgent action to reduce emissions across all GHG categories is necessary to minimize global warming and avoid the most destructive effects of climate change.[31] The report details five possible future emissions and warming scenarios: two high-emissions scenarios (SSP3-7.0 and SSP5-8.5), an intermediate scenario with emissions similar to current levels through 2050 (SSP2-4.5), and two relatively low-emissions scenarios (SSP1-1.9 and SSP1-2.6). Of these, only the two low-emissions scenarios are likely to result in temperature increases below the Paris Agreement's[32] target of limiting, by the end of the century, the increase in the global average surface temperature to 2.0° Celsius (C) above temperature

[29] EPA, "Overview of Greenhouse Gases," https://www.epa.gov/ghgemissions/overview-greenhouse-gases (last accessed September 5, 2024).

[30] EPA, "Importance of Methane," https://www.epa.gov/gmi/importance-methane (last accessed July 20, 2022).

[31] PHMSA acknowledges much of the discussion in section II and elsewhere in this final rule is focused on methane emissions from natural gas pipeline facilities, as those facilities constitute the great majority of gas pipeline facilities subject to parts 191 and 192. However, PHMSA parts 191 and 192 requirements are not limited to natural gas pipelines; rather, they also apply to pipeline facilities transporting other gases which are flammable, toxic, or corrosive — releases of which may entail significant public safety or environmental consequences (including potential contributions to climate change) in their own right. See §§ 191.3 and 192.3 (definitions of "gas" for the purposes of parts 191 and 192, respectively).

[32] The Paris Agreement, https://unfccc.int/process-and-meetings/the-paris-agreement

levels recorded in the 1850s,[33] and only the very low-emissions scenario SSP1-1.9 is likely to limit warming to 1.5° C by the end of the century (specifically, between 1.0° to 1.8° C above temperature levels from the 1850s, consistent with the Paris Agreement). Both low-emissions scenarios require cutting methane emissions by approximately half of 2015's emission-rate levels before 2050.[34] Rapid and full-scale efforts to reduce methane and other GHG emissions are needed to achieve the very low-emissions scenario SSP1-1.9.[35] In contrast, the intermediate scenario SSP2-4.5 results in potentially dangerous warming of 2.0° C by 2050, rising to between 2.1° to 3.5° C by 2100. Section 4.1 of the 2023 IPCC Report reiterates the need to address emissions of methane and other non-CO_2 pollutants, noting with high confidence that scenarios that limit warming to 1.5° C or 2.0° C by 2100 would require methane emissions reductions of 34 percent or 24 percent, respectively, on average by 2030.[36]

The 2021 IPCC Report describes the scientific findings that increased global surface temperature, extreme weather events, rising sea levels, and other consequences of climate change exist today and are projected to worsen in the coming decades without immediate action to control GHG. Higher average surface temperatures will result in sea level rise, severe heat waves, and more intense extreme weather events (hurricanes, storms, droughts, and floods), in turn altering water supplies, damaging habitats, and promoting wildfires. The National Climate

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[33] 2021 IPCC Report, 1.2.

[34] 2021 IPCC Report, SPM-16, Table SPM.1.

[35] 2021 IPCC Report, Table SPM.1.

[36] 2023 IPCC Report Section 4.1

Assessment Reports released by the U.S. Global Change Research Program[37] found that these dimensions of climate change will have severe consequences for the human population throughout the United States, including altering population distributions; billions of dollars in damage to private property and public infrastructure; compromised local economies; disrupted agriculture, fisheries, and other ecosystems; and negative impacts to public health and safety.

According to NOAA's Annual 2023 Global Climate Report, 10 of the hottest years since recordkeeping began 174 years ago occurred within the last decade, and 2023 was the warmest year ever recorded with average global surface temperatures 2.12 degrees Fahrenheit (F) (1.18° C) warmer than the average temperature in the 20th century (57.0° F).[38] Higher average surface temperatures mean that heat waves everywhere will become more frequent and more intense,[39] with corresponding consequences to human health, the environment, and economic activity. The estimated frequency and intensity of extreme heat events will increase further with additional warming, especially in the summer months.[40]

Another consequence of elevated surface temperatures is rising sea levels. The global average sea level rose by approximately 5.9 to 9.8 inches (0.15 to 0.25 meters) between 1901 and 2018, and the rate of increase and degree to which sea level rise can be attributed with

[37] See U.S. Global Change Research Program, Climate Science Special Report: Fourth National Climate Assessment, Volume I (2017); U.S. Global Change Research Program, Climate Change Impacts in the United States: The Third National Climate Assessment (2014); U.S. Global Change Research Program, The Fifth National Climate Assessment (2023).

[38] See NOAA National Centers for Environmental Information, Monthly Global Climate Report for Annual 2023 (January 2024), ncei.noaa.gov/access/monitoring/monthly-report/global/202313 .

[39] 2021 IPCC Report, SPM-8, SPM-18.

[40] 2021 IPCC Report, SPM-23.

confidence to anthropogenic climate change have both increased since 1971.[41] The IPCC has determined that it is "virtually certain" that the global sea level will rise further by 2100,[42] with projections suggesting the global sea level will rise an additional 2 feet by 2100 under intermediate-emissions scenarios consistent with current emissions trends, with a global average sea level rise as high as 6.9 feet possible by 2100 under higher-emissions scenarios.[43] Further, rising average surface temperatures also alter water cycles and weather patterns, resulting in drought, flooding, and related hazards such as wildfires.[44] Scientists have observed that hurricanes have become stronger and more intense and determined that anthropogenic climate change has increased rainfall rates associated with hurricanes and other tropical cyclones.[45] Section II.B of the NPRM described in greater detail the widespread and potentially catastrophic environmental consequences of climate change.[46]

The United States is already experiencing the effects of climate change, most notably through extreme heat and drought events. Recent examples include the 20-year-plus drought impacting the Colorado River system[47] and the 2021 heatwave that shattered high temperature

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[41] 2021 IPCC Report, SPM-6.

[42] 2021 IPCC Report, SPM-28.

[43] U.S. Global Change Research Program, Ch. 9. Coastal Effects in Fifth National Climate Assessment. (2023). Pg. 9-7.

[44] 2021 IPCC Report, SPM-15.

[45] 2021 IPCC Report, SPM-9.

[46] PHMSA cited largely to the 2021 IPCC report and the Third and Fourth National Climate Assessments in the NPRM. The Fifth National Climate Assessment [USGCRP, 2023: Fifth National Climate Assessment. Crimmins, A.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, B.C. Stewart, and T.K. Maycock, Eds. U.S. Global Change Research Program, Washington, DC, USA. https://doi.org/10.7930/NCA5.2023] has since been published, providing additional research and information on recent climate change impacts.

[47] Yanchin, "Interior Threatens Colorado River Cuts," E&E News (Oct. 28, 2022), https://www.eenews.net/articles/interior-threatens-colorado-river-cuts/.

records in several western States[48] and resulted in 143 excess heat-related deaths in Washington, 119 deaths in Oregon, and 13 deaths in California.[49] The 10 warmest years in the 174-year temperature record have all occurred within the past decade of 2014 to 2023.[50] Higher average surface temperatures and extreme instantaneous temperatures have also exacerbated wildfires in the United States. The Fifth National Climate Assessment report concluded with high confidence that the wildfires in the U.S. Southwest "have become larger, more frequent, and in many areas, more severe, with clear evidence of climate change as a major cause."[51] The assessment illustrated the significant impacts of severe wildfires in the U.S. Southwest, stating that "three of the five deadliest fires on record in California have occurred since 2017, costing 112 lives," and noting that additional fatalities can be attributed to wildfire smoke, exacerbation of COVID-19 symptoms, and earth movement associated with post-fire debris flows.[52] Fires in 2020 alone resulted in billions of dollars in costs to U.S. Southwest residents from direct property damage and firefighting costs and related costs from damage to water resources and agricultural products.

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[48] Di Liberto, Tom, "Record-breaking June 2021 heatwave impacts the U.S. West," *NOAA Climate.gov,* June 23, 2021, https://www.climate.gov/news-features/event-tracker/record-breaking-june-2021-heatwave-impacts-us-west

[49] U.S. Department of Health and Human Services, Office of Climate Change and Health Equity, Climate and Health Outlook: Extreme Heat (June 2022), https://www.hhs.gov/sites/default/files/climate-health-outlook-june-2022.pdf. British Columbia experienced 619 excess heat-related deaths. British Columbia, "Minister's Statement on 619 Lives Lost During 2021 Heat Dome" (June 7, 2022). https://news.gov.bc.ca/26965.

[50] NOAA's National Centers for Environmental Information. "2023 was the warmest year in the modern temperature record." (January 17, 2024). https://www.climate.gov/news-features/featured-images/2023-was-warmest-year-modern-temperature-record#:~:text=Details,decade%20(2014%E2%80%932023).

[51] U.S. Global Change Research Program, Ch. 28. Southwest in Fifth National Climate Assessment. (2023). pg. 26. nca2023.globalchange.gov/chapter/28

[52] U.S. Global Change Research Program, Ch. 28. Southwest in Fifth National Climate Assessment. (2023). pg. 28. nca2023.globalchange.gov/chapter/28/

The United States has and will continue to experience dramatically altered precipitation and weather patterns from climate change along with increasing storm severity. Scientists have already observed increased North Atlantic Ocean hurricane formation,[53] and intersecting risks from sea level rise, more intense storm surges, and longer duration hurricanes can increase the consequences of coastal flooding during storms.[54] For example, the Fifth National Climate Assessment cites recent research suggesting that the rainfall associated with 2017's Hurricane Harvey, which caused severe flooding to the Houston metropolitan area, was "estimated to be about 15-20 percent heavier than it would have been without human-caused warming."[55] Sea level rise has already led to more frequent high tide flooding; one study of flooding in 27 communities cited in the Fourth National Climate Assessment found that the frequency of high tide flooding in several communities has increased by a factor of 5 or more, and that such flooding increased by a factor of 10 or more in Atlantic City (NJ), Baltimore (MD), Annapolis (MD), Wilmington (DE), Port Isabel (TX), and Honolulu (HI).[56] The Fifth National Climate Assessment estimated approximately $258 billion per year in damage to structures and crops from flooding exacerbated by climate change and estimated between $0.55 to 2.6 trillion of

[53] U.S. Global Change Research Program, Ch. 2. Climate Trends in Fifth National Climate Assessment. (2023). Pg. 20. Nca2023.globalchange.gov/chapter/2/

[54] U.S. Global Change Research Program, Ch. 21. Northeast in Fifth National Climate Assessment. (2023). Pg. 8. Nca2023.globalchange.gov/chapter/21/

[55] U.S. Global Change Research Program, Ch. 2. Climate Trends in Fifth National Climate Assessment. (2023). Pg. 4. Nca2023.globalchange.gov/chapter/2/

[56] Sweet, W. & Park, J., "From the Extreme to the Mean: Acceleration and Tipping Points of Coastal Inundation from Sea Level Rise, Earth's Future. Volume 2, Issue 12 at 579-600 (December 18, 2014).

future coastal property damage from sea level rise in a very high-emissions scenario.[57] In addition to the other costly and deadly impacts of climate change in the United States described in this section, flooding from major hurricanes and other severe storms has already resulted in billions of dollars in property damage and the loss of several lives.

The increased intensity and frequency of extreme weather events influenced by climate change can wreak havoc on public services and infrastructure, especially pipeline facilities. For example, well-documented threats to pipeline infrastructure from natural force damage (which includes incidents caused by acts of nature such as flooding, land movement, and lightning) are likely to be exacerbated by climate change. Flooding can also threaten pipeline integrity by causing direct damage to aboveground, safety-critical components such as valves, pressure regulators, relief devices, and pressure sensors. A weather-induced failure of a gas pipeline can result in releases that threaten public safety and further contribute to climate change. Section II.B discusses the direct threats posed to pipeline infrastructure due to climate change impacts, along with PHMSA's recent efforts to alert operators to these threats through advisory bulletins.

The consequences of climate change have been, and are expected to continue to be, disproportionately borne by vulnerable populations in the United States—in particular by minority and low-income populations, outdoor laborers, children, and the elderly.[58] Some communities of color may be uniquely vulnerable to climate change health impacts in the United

[57] U.S. Global Change Research Program, Ch. 19. Economics in Fifth National Climate Assessment. (2023). pgs. 7-9.

[58] U.S. Global Change Research Program, The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment - Executive Summary at 6 (2016).

States because they live in areas where the impacts of climate change (e.g., extreme temperatures and flooding) are likely to be the most significant and because these communities tend to rely more on climate-sensitive resources (such as local water and food supplies), economic opportunities (e.g., seasonal labor), and have limited access to social and information resources. For example, the Fifth National Climate Assessment found that environmental justice communities and other vulnerable populations are disproportionately exposed to the direct and indirect consequences of wildfires.[59] The 2016 scientific assessment on the *Impacts of Climate Change on Human Health* similarly found that social determinants of health (e.g., access to healthcare, economic stability) are highly likely to contribute to climate change-related health impacts.[60] And insofar as gas transmission and gas gathering pipeline infrastructure is often located in the vicinity of socially vulnerable populations,[61] these populations would face the greatest risks in the event of a release from a gas pipeline damaged by climate change-induced extreme weather events.

3. Methane Emissions from Gas Pipeline Facilities

Most natural gas produced or consumed in the United States is transported by pipeline at some stage of its lifecycle. PHMSA is, by statute (49 U.S.C. 60101 et seq.), responsible for regulating the safety of the interstate transportation of gas by pipeline facilities, which can

[59] U.S. Global Change Research Program, Ch. 28. Southwest in Fifth National Climate Assessment. (2023). pg. 29. nca2023.globalchange.gov/chapter/28

[60] U.S. Global Change Research Program, The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment at page 21 (2016).

[61] See Emanuel et al., "Natural Gas Gathering and Transmission Pipelines and Social Vulnerability in the United States," 5 GeoHealth (June 2021).

include the gathering, transmission, distribution, and storage of natural gas as well as other gases regulated under parts 191 and 192.[62] Federal law, however, provides that certified State agencies have jurisdiction to regulate safety of intrastate gas pipeline facilities. Certain certified State programs may also inspect interstate pipelines under an agreement with PHMSA. Both Federal and State regulation of gas pipeline facilities have historically been directed toward the direct and immediate risks to public safety associated with the ignition of natural gas releases and less to direct threats to the environment, including climate change risks posed by unignited released methane.[63]

Gas Pipeline Facilities

PHMSA regulations cover several types of gas pipeline facilities, including gas gathering pipelines, gas transmission pipelines, gas distribution pipelines, LNG facilities, and UNGSFs.

Gathering Pipelines

A gas gathering pipeline is defined in the PSR at § 192.3 as a pipeline that transports gas from a production facility to a transmission pipeline or distribution main. More generally, these pipelines "gather" gas from production facilities for transport to a gas processing plant for further transportation by transmission pipelines. The precise points where a gathering pipeline begins and ends are defined in the PSR at §§ 192.8 and 192.9 and in the first edition of API

[62] Parts 191 and 192 govern not only natural gas, but also any "flammable gas, or gas which is toxic or corrosive." See §§ 191.3 and 192.3 (definitions of "gas"). Consequently, the revisions to parts 191 and 192 within this final rule will apply not only to natural gas pipelines but also to other gas pipeline governed by parts 191 and 192.

[63] PHMSA acknowledges that in revising its Pipeline Safety Regulations over the years, it has identified environmental benefits of those efforts in much the same way that it has identified other benefits (e.g., reduced compliance cost for operators, equity, etc.) of those rulemakings. However, PHMSA submits those non-safety benefits were generally presented as secondary benefits of safety-focused regulatory amendments.

Recommended Practice 80, "Guidelines for the Definition of Onshore Gas Gathering Lines"[64] through incorporation by reference.

Section 192.9(b) provides that offshore gas gathering pipelines are generally subject to the same part 192 requirements as gas transmission pipelines. Section 192.8 also defines three types of regulated onshore gas gathering pipelines subject to part 192 requirements: Type A, Type B, and Type C gathering pipelines. Operators reported 8,582 miles of Type A gathering pipelines, 4,620 miles of Type B gathering pipelines, 92,927 miles of Type C gathering pipelines, and 5,231 miles of offshore gathering pipelines in their 2023 annual reports. Type A and Type B gathering pipelines are, by definition, located in Class 2, Class 3, or Class 4 locations.[65] Type A gathering pipelines operate at higher pressures and are subject to most part 192 safety requirements applicable to gas transmission pipelines, while Type B gathering pipelines operate at lower pressures and are subject to a smaller subset of specific part 192 safety requirements listed in § 192.9(d). The Type C gathering pipeline designation was established in the final rule titled "Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation or Large, High-Pressure Lines, and Other Related Amendments" published on November 15, 2021.[66] Type C gathering pipelines are located in Class 1 locations,

[64] API, Recommended Practice 80: Guidelines for the Definition of Onshore Gas Gathering Lines (Apr. 2000) (API RP 80).

[65] Class location is defined at § 192.5.

[66] 86 FR 63266, "Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments," (Gas Gathering Final Rule, Nov. 15, 2021). Certain smaller-diameter Type C gas gathering pipelines are the subject of a temporary enforcement discretion whereby PHMSA has committed not to pursue enforcement action against those pipelines for alleged violations of certain part 192 safety requirements before May 17, 2024. See PHMSA, "Notice of Limited

have an outside diameter greater than or equal to 8.625 inches, and operate at high pressure.[67] These pipelines are subject to scaled safety requirements listed in § 192.9(e), with more part 192 safety requirements applicable as a function of the risk posed to public safety. This relative risk is based on the diameter of the Type C segment, which affects the potential energy of a pipeline rupture and explosion, and its proximity to nearby populated structures. For example, § 192.9(e) provides that, while all Type C lines are required to carry out a damage prevention program, leak survey requirements only apply to either the largest Type C lines (those pipelines with an outside diameter greater than 16 inches), or those Type C lines with smaller diameters (8.625 inches to 16 inches) that are near buildings intended for human occupancy.

Type A, Type B, and certain Type C gathering pipelines (namely, those Type C gathering pipelines that are installed, replaced, relocated, or otherwise changed after May 16, 2023) must comply with the design, construction, initial inspection, and initial testing requirements applicable to gas transmission lines and must therefore be constructed from similar materials. According to annual reports submitted to PHMSA, gas transmission pipelines and Type A and Type B onshore gathering lines are generally made from steel and, to a lesser extent, polyethylene plastic. An operator may also use pipelines constructed with two polyamide compounds: PA-11 and PA-12. With notification to PHMSA, composite materials[68] may be used

Enforcement Discretion for Particular Type C Gas Gathering Pipelines" (July 8, 2022), https://www.phmsa.dot.gov/news/notice-limited-enforcement-discretion-particular-type-c-gas-gathering-pipelines.

[67] See the pressure criteria in the second column of table 1 in § 192.8(c)(2).

[68] "Composite materials" are defined in § 192.3 as materials used to make pipe or components manufactured with a combination of either steel and/or plastic and with a reinforcing material to maintain its circumferential or longitudinal strength.

on a Type C gathering pipeline. PHMSA expects that most Type C gathering pipelines, which have operational characteristics similar to gas transmission and Type A regulated gas gathering pipelines, are made of steel, but Type C pipelines existing prior to May 16, 2023, may have been constructed with non-standard materials.

Transmission Pipelines

A gas transmission pipeline is defined in the PSR at § 192.3 to include any pipeline, other than a gathering pipeline, that transports gas from a gathering pipeline or storage facility to a distribution center, storage facility, or large-volume customer (such as a gas power station or an LNG facility). Additionally, a pipeline other than a gathering pipeline that operates at a hoop stress of 20 percent or more of the specified minimum yield strength (SMYS),[69] or that transports gas within a storage field, is also classified as a gas transmission pipeline. An operator may also voluntarily designate a pipeline as a gas transmission pipeline that would otherwise meet the definition of a gas gathering pipeline or gas distribution pipeline. In 2023, operators reported 297,552 miles of gas transmission pipelines on their annual reports. Gas transmission pipelines are typically steel, large-diameter (6 to 48 inches), high-pressure lines (typically operating at pressures between 200 and 1500 pounds per square inch) transporting large volumes of gas over long distances.

Distribution Pipelines

[69] SMYS is defined in 49 CFR 192.3 to mean specified minimum yield strength, which is a measure of tensile strength. As an example, Trade B pipe made to API 5L specification has a specified minimum yield strength (SMYS) of 35,000 pounds per square inch (psi) 40 percent of SMYS (35,000 x 0.40) is 14,000 psi.

A gas distribution pipeline is defined in the PSR at § 192.3 as a pipeline other than a gas transmission pipeline or gathering pipeline. Distribution pipelines are typically a part of a system that transports gas received from a transmission pipeline at a distribution center to homes and businesses through a network of gas mains and service pipelines.[70] A gas distribution service pipeline feeds gas to individual customers, while a distribution main is the common source of supply for two or more distribution service pipelines. In 2023, distribution operators reported 2,352,100 miles of gas distribution mains and service lines on their annual reports. While virtually all gas transmission piping is fabricated from steel, gas distribution pipeline materials vary depending on the vintage and usage. Modern gas distribution systems are predominantly composed of polyethylene plastic and protected steel (i.e., coated with corrosion-resistant materials and/or equipped with cathodic protection); older systems may contain cast-iron or bare steel piping that is not protected against corrosion. Distribution pipelines made of copper, wrought iron, and non-polyethylene plastic also exist but are less common.

LNG Facilities

[70] Under 49 U.S.C. 60105 and 60106, States may assume safety authority over intrastate gas pipelines through certifications and agreements with PHMSA. Currently, the District of Columbia, Puerto Rico, and all States except Alaska and Hawaii exercise safety oversight authority over all intrastate gas distribution pipelines within State lines. These State programs conduct regular inspections and enforce State safety regulations over intrastate distribution pipelines. See PHMSA's State Programs website for more information: https://www.phmsa.dot.gov/working-phmsa/state-programs/state-programs-overview (last accessed Aug. 30, 2024).

An LNG facility is defined in the PSR at part 193[71] as a gas pipeline facility that is used for liquefying natural gas or synthetic gas or for transferring, storing, or vaporizing LNG. LNG is natural gas or synthetic gas (with methane as its principal constituent), that has been changed to a liquid, thereby reducing the volume of the gas to facilitate storage and long-distance transportation. LNG facilities include gas pipeline facilities that either change gas into LNG through a liquefaction process or that change LNG back into a vapor or gaseous state through a vaporization process. LNG facilities also include transfer piping systems that transfer LNG between any of the following: liquefaction process facilities, storage tanks, vaporizers, compressors, cargo transfer systems, and facilities other than gas pipeline facilities. In 2023, operators reported 173 in-service LNG facilities on their annual reports. LNG facilities are subject to the safety requirements in part 193 of the PSR.

Underground Natural Gas Storage Facilities

An UNGSF is defined in the PSR at § 192.3 as a gas pipeline facility that stores natural gas underground incidental to the transportation of natural gas, including: (1) a depleted hydrocarbon reservoir; (2) an aquifer reservoir; or (3) a solution-mined salt cavern. In addition to the storage reservoir or cavern itself, an UNGSF includes: injection, withdrawal, monitoring, and observation wells; wellbores and downhole components; wellheads and associated wellhead piping; wing-valve assemblies that isolate the wellhead from connected piping beyond the wing-valve assemblies; and any other equipment, facility, right-of-way, or building used in the

[71] Part 193 requirements may change as a result of regulatory amendments proposed in a forthcoming notice of proposed rulemaking issued under RIN 2137-AF45. PHMSA's references to part 193 within this final rule—including the proposed amended regulatory text at its conclusion—reflect current regulatory text and organization.

underground storage of natural gas. Most underground natural gas storage occurs in depleted natural gas reservoirs. UNGSFs are subject to specific safety requirements set forth in § 192.12.

Sources of Emissions from Gas Pipeline Facilities

Emissions of methane and other gases occur in all sectors of the natural gas industry—from production and extraction facilities, gathering pipelines, processing facilities, transmission pipelines, distribution pipelines, and end user facilities.[72] Emissions occur during normal operation, routine maintenance, and abnormal conditions, such as incidents. Gas pipeline facilities emit methane and other gases in the form of "fugitive emissions" from system upsets, such as incidents and abnormal operations that result in the release of gas; leaks from line pipe, flanges, valves, meter sets, and other equipment; and intentional releases, such as when a gas pipeline facility is blown down for repairs or maintenance, or through pressure relief device operation as designed or configured. Older pipelines and pipelines known to leak based on their material (e.g., legacy materials such as cast iron, wrought iron, unprotected steel, and certain historic plastics), design, or past O&M history are generally more susceptible to leaks.

The EPA compiles and publishes data on the magnitude and sources of methane emissions from gas gathering, transmission, and distribution pipelines and other gas pipeline facilities. The EPA has two complementary programs for characterizing GHG emissions such as

[72] Although the evaluation of release data discussed in this section II.C.2 and subsequent sections is focused on the location, frequency, and severity of leaks on natural gas pipeline facilities, that analysis is largely applicable to leaks on other part 192-regulated gas pipeline facilities. Indeed, certain part 192-regulated gas pipeline facilities (e.g., gas pipeline facilities transporting hydrogen gas) may be particularly susceptible to leaks because of (inter alia) the smaller size of hydrogen gas molecules compared to methane molecules of which natural gas is mostly composed.

methane: the Inventory of Greenhouse Gas Emissions and Sinks (Greenhouse Gas Inventory, or GHGI), and the Greenhouse Gas Reporting Program (GHGRP).

- The GHGI represents official U.S. Government data on national GHG emissions and sinks over time by gas, source/sink, and economic sector and fulfills annual existing commitments under the UNFCCC and Paris Agreement. The2024 GHGI estimates total annual national-level GHG emissions using many data inputs, including the GHGRP, research studies, and national and subnational activity data sets. The most recent final GHGI (2024 GHGI) includes estimates from 1990 through 2022.[73] The GHGI includes estimates of GHG emissions in five methodological chapters: Energy; Industrial Processes and Product Use; Agriculture; Land Use, Land Use Change, and Forestry; and Waste. The GHGI is updated annually.
- The GHGRP has, since 2010, collected facility-level emissions data from certain large GHG emission sources, fuel and industrial gas suppliers, and CO_2 injection sites in the United States, including large suppliers or facilities that emit more than 25,000 metric tons of CO_2 equivalent per year.[74]

For the 2023 reporting year, 40 CFR part 98, subpart W facilities in the GHGRP included 161 reports from gas distribution pipeline operators and 44 reports from gas transmission

[73] EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2022. EPA 430-R-24-004. (April. 11, 2024). https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2022. (2024 GHGI).

[74] In the reporting to the GHGRP, facilities are required to apply a global warming potential of 25 metric tons of CO2 equivalent for CH4. (40 CFR 98, Table A-1 to Subpart A of Part 98) Beginning in 2025, reporters to the GHGRP will be required to apply an updated GWP of 28 for CH4 (89 FR 31812).

pipeline operators. However, the GHGRP applies only to petroleum and natural gas systems facilities, as defined in the rule, that emit 25,000 metric tons of carbon dioxide equivalent (CO2e) or more per year. Therefore, not all pipelines subject to PHMSA regulations will be subject to reporting under the GHGRP. For example, the 44 gas transmission pipeline operators submitting reports under the GHGRP for the 2022 reporting year correspond to approximately two-thirds of gas transmission pipeline mileage nationwide.[75] The creation of the GHGRP was provided for by Congress in the fiscal year 2008 Consolidated Appropriations Act (Pub. L. 110-161) and promulgated under section 114 of the Clean Air Act.[76] Petroleum and natural gas systems, including natural gas distribution facilities, onshore natural gas gathering and boosting, onshore natural gas transmission pipelines (including compression), and LNG storage and terminal facilities are covered under 40 CFR part 98, subpart W, and GHGRP data for the relevant facilities must be reported to the EPA by March 31 of each year.

The GHGI estimates for methane emissions are developed using GHGRP, research studies, and national and subnational activity data sets. For example, to estimate emissions from plastic distribution main line leaks, an emission factor in units of kg of CH_4 per mile for that material is multiplied by an activity factor of the reported mileage of plastic distribution mains from PHMSA annual reports. Each itemized emissions segment or source in the GHGI has its own emissions factor, in many cases derived from GHGRP data. The EPA annually updates the

[75] One operator may submit multiple GHGRP reports if they operate multiple systems or in multiple states.
[76] 42 U.S.C. 7414.

methodology in the GHGI to improve accuracy and completeness.[77] The current GHGI quantifies emissions from leaks in pipelines using the following approaches and data:

- Gathering pipeline leaks. Emission factors and the activity factor are developed using year-specific GHGRP data. GHGRP data are reported by pipeline material type.
- Transmission pipeline leaks. Data gathered from a joint EPA and Gas Research Institute (GRI) report in 1996 (EPA/GRI 1996)[78] were used to develop the emission factor. PHMSA mileage data are used for the national activity factor.
- Distribution pipeline leaks. Data from Lamb et al. 2015[79] were combined with EPA/GRI 1996 to develop the material-specific emission factors. PHMSA main mileage and service line count data, by pipeline material type, are used for the national activity factor.

Recent research using modern leak detection equipment indicates that overall fugitive methane emissions from gas pipeline facilities may be significantly underestimated in current methane emissions estimates. The methodology of multiplying an activity factor, such as pipeline mileage, by an emissions factor to extrapolate an estimate of overall emissions for a given source is considered a "bottom-up" approach that can be contrasted with a "top-down"

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[77] Refer to tables 3.6-2, 3.6-6, and 3.6-17 of Annex 36 of the 2022 GHGI for more information on the methodologies or data sources used by EPA to develop each emissions factor.

[78] Harrison, M. et al. EPA & Gas Research Institute, Methane Emissions from the Natural Gas Industry (June 1996) (the 1996 GRI/EPA Report).

[79] Lamb et al., "Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States," 49 Environmental Science & Technology 5161 (Mar. 31, 2015).

approach taking total emissions measured at larger (e.g., national) scales and attributing emissions to specific sources through modeling. Top-down approaches regularly estimate higher total emissions in the atmosphere than have been estimated by bottom-up approaches, which is sometimes referred to as the "top-down/bottom-up gap." For example, recent analyses released in early 2022 using top-down methods from the International Energy Agency (IEA) found that global methane emissions from the energy sector are about 70 percent greater than the official statistics reported by national governments.[80] The IEA used satellite-based sensor technologies, atmospheric methane measurements, and data-processing techniques to capture total emissions over large areas and attributed those emissions to facility-level sources, rather than multiplying activity factors by bottom-up emissions factors. Other studies comparing the two approaches have consistently shown that bottom-up approaches may underestimate total U.S. methane emissions by 50 percent or more.[81] One explanation suggested the significant discrepancy in estimated emissions is due to bottom-up methods under-sampling large but infrequent emissions events, such as malfunctions and venting, possibly due to the difficulty and risks associated with

[80] IEA, Press Release, "Methane emissions from the energy sector are 70% higher than official figures" (published Feb. 23, 2022), https://www.iea.org/news/methane-emissions-from-the-energy-sector-are-70-higher-than-official-figures. IEA's analysis may underestimate the full extent of methane emissions as satellite data used by the organization do not provide complete coverage of all global oil and gas operations. (last accessed Aug. 30, 2024).

[81] Zavala-Araiza et al., "Reconciling Divergent Estimates of Oil and Gas Methane Emissions," 112 Proceedings of the National Academy of Sciences of the United States of America 11597-98 (Dec. 22, 2015); Lyon et al., "Constructing a Spatially Resolved Methane Emission Inventory for the Barnett Shale Region," 49 Environmental Science & Technology at 8147, 8154 (July 7, 2015); Alvarez et al., "Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain," Science 186 (June 21, 2018).

taking samples during such events.[82] Furthermore, as discussed below, recent research also indicates that the potential under-estimation of pipeline facility emissions could be particularly pronounced in connection with distribution and gathering pipelines. The EPA recently made adjustments to its GHGRP data collection for reporting equipment leaks from natural gas distribution sources, including pipeline mains and services, below grade transmission-distribution transfer stations, and below grade metering-regulating stations, and for reporting emissions from equipment at onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities.[83] Additional discussion of emissions factors for gas pipelines is available in the RIA for this final rule in the rulemaking docket.

Methane Emissions Data—All Natural Gas Pipeline Facilities

The 2024 GHGI estimated the annual net methane emissions from U.S. natural gas systems in 2022 to be 6,183 thousand metric tons (kt).[84] Gas transmission, gas distribution, transportation-related gas and LNG storage, and certain types of gas gathering lines, as those facilities are determined in the PSR at § 192.8, are regulated by PHMSA. On the other hand,

[82] Brandt et al., "Methane Leakage from North American Natural Gas Systems," Science 343, 345 (Feb. 13, 2014); Zavala-Araiza et al., 2015, at 15598; Lyon, at al., 2015, at 8147, 8155; Alvarez et al., 2018, at 183. The authors of the Brandt, Zavala-Araiza, and Lyon studies also suggest that this underestimation of emissions could be due to (or exacerbated by) incomplete activity factors that omit certain emissions source activities (such as inaccurate component counts or even the omission of entire facilities). Further, the authors of the Brandt study point to limited sample sizes and changing technologies as other potential sources of error in bottom-up emissions estimates.

[83] EPA, "Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems" 89 FR 42062. (May 14, 2024). (EPA 2024 GHGRP Final Rule).

[84] 2024 GHGI, Table 3-74 at page 3-97. Natural gas systems include exploration, production, gathering, processing, transmission, storage, distribution, and post-meter releases of gas. The 2022 GHGI inventory introduced estimates of post-meter emissions. Emissions from power generation are estimated elsewhere in the GHGI.

exploration, production, gas processing plants, and Type R gas gathering lines are not regulated by PHMSA. Assuming approximately one-third of gathering and boosting emissions are from regulated gas gathering lines, approximately half of net methane emissions from natural gas systems are from PHMSA-regulated pipeline facilities. The sector classifications used in the GHGI for gathering lines do not correspond precisely with the definitions in the PSR. In the EPA's GHGI, the gathering and boosting sources include compressor stations (with multiple sources on site) and gathering pipelines. Those sources include PHMSA-regulated gas gathering lines, Type R gathering lines, and some other pipelines and activities that are better described as production and not transportation.[85] The GHGI data cited in this section is for natural gas systems and therefore would be covered under the regulatory classifications in 49 CFR part 192. The EPA definition of "gathering and boosting" is similar in principle to the definition of a gas "gathering line" in 49 CFR part 192, although it references some gas treatment processes that could be classified as a "production operation" rather than as a gathering pipeline under § 192.9 and the first edition of API RP 80, and therefore would not be under PHMSA's jurisdiction. However, for the purposes of estimating emissions from leaks and incidents on PHMSA-regulated gas gathering pipelines, PHMSA believes that the emissions rate associated with "pipeline leaks" from "gathering and boosting" piping as defined by the EPA would not be significantly different than the emissions rate for gas gathering pipelines as defined by PHMSA.

While natural gas exploration and production (i.e., the upstream sector) is the single largest source category in the GHGI, approximately one-third of total methane emissions are

[85] 2024 GHGI. Pg. 3-95.

attributed to transmission, storage, and distribution systems, and an additional one-fourth of total methane emissions is attributed to natural gas gathering and boosting systems. A summary of these high-level emissions estimates is shown in the table below and represent the net methane emissions[86] for 2022 from section 3.7 and annex 3.6 of the 2024 GHGI. These figures represent only methane emissions and do not include, for example, CO_2 emissions from compressors.

2024 GHGI: 2022 Natural Gas Systems Net Methane Emissions

Source	Kt CH_4	Percentage of Total Methane Emissions
Exploration and Production (excluding gathering)	1,673	27
Gathering and Boosting	1,528	25
Processing Plants	541	9
Transmission, Storage, and LNG	1,413	23
Distribution	544	9
Post-meter	477	8
Total	6,177	100

Methane Emissions Data—Natural Gas Distribution Pipelines

The GHGI estimates that in 2020, approximately half of methane emissions from natural gas distribution systems were caused by leaks from, and incidents on, gas distribution line pipe. Leaks from customer meters, meter stations, and regulator stations comprise most of the remaining emissions. Recent studies indicate, however, that the current methane emissions data likely significantly underestimates methane emissions from gas distribution pipelines. For example, a national study focusing on the natural gas distribution sector estimated emissions

[86] Net emissions estimates include estimated emissions reductions from reported implementation of EPA Methane Challenge Program and Gas STAR best practices by operators in the production, transmission and storage and distribution sectors and estimated reductions from EPA regulatory requirements.

from gas distribution mains that were five times larger than those in the GHGI estimate for 2017 (0.69 million metric tons of methane vs. 0.14 million metric tons)[87] and, by extension, the GHGI estimate for 2022 as well (0.69 million metric tons of methane vs. 0.12 million metric tons).[88] The current methodology for calculating the emissions factors from natural gas distribution main and service pipelines in the 2024 GHGI was most recently updated in 2016[89] and relies on EPA/GRI 1996 and the 2015 Lamb et. al study. The 2020 study by Weller et.al. attributed the differences in emissions to a larger number of leaks than previously estimated and better quantification of the largest leaks from the distribution sector (so-called "super-emitter" leaks), which contribute significantly to overall emissions.[90]

2024 GHGI: 2022 Natural Gas Distribution Systems Emissions by Category

Source	Kt CH_4	Percentage of Total Sector Emissions
Main Pipeline Leaks	124.7	22.9
Service Pipeline Leaks	64.9	11.9
Abnormal Operating Conditions (e.g., Incidents)	69.7	12.8
Meter/Regulator Stations	45.4	8.4
Customer Meters	236.3	43.4
Pipeline Blowdown	1.8	0.3
Relief Device Venting	1.3	0.2
Total	544.1	100
Note: the PHMSA definition of a service pipeline in § 192.3 includes the customer meter in most configurations		

[87] Weller et al., "A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems," 54 Environmental Science & Technology 8958, 8966 (June 10, 2020).

[88] EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2022, Annex 3.6-1 (Apr. 11, 2024).

[89] EPA. "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2014: Revisions to Natural Gas Distribution Emissions". Pgs. 10-13. (April 2016). https://www.epa.gov/sites/default/files/2016-08/documents/final_revision_ng_distribution_emissions_2016-04-14.pdf.

[90] Weller et al., 2020, at 8958-59.

Unlike natural gas transmission systems, the GHGI separately estimates emissions from natural gas distribution mains and service pipelines by construction material.[91] PHMSA has monitored trends in legacy pipe materials for years, as these materials pose safety risks.[92] The GHGI data demonstrates that replacing leak-prone pipe, such as aging cast-iron pipe, can have a significant effect in reducing methane emissions from gas distribution systems. Despite dramatically increased natural gas production and consumption between 1990 and 2022, net methane emissions from natural gas distribution systems have fallen steadily from 1,819 kt CH_4 in 1990 to 544.1 kt CH_4 in 2022, as quantified by the 2024 GHGI. This reduction in methane emissions corresponds to a decline in cast-iron and cathodically unprotected steel pipe mileage over the same period. And while cast-iron mains currently represent less than 1 percent of total distribution main miles—approximately 16,337 miles of cast-iron or wrought-iron distribution main remain in place as of 2023—leaks on such facilities account for approximately 15 percent of the GHGI's estimated total fugitive emissions from all natural gas distribution mains in 2022. Additionally, PHMSA incident report data shows that cast-iron mains are vulnerable to integrity failures resulting in incidents; around 8 percent of the incidents that occurred on gas distribution mains between 2010 and 2023 occurred on cast-iron mains, although they represent only 1 percent of gas distribution main mileage. GHGI and PHMSA data, therefore, demonstrate that replacing leak-prone materials on gas distribution pipelines can reduce fugitive emissions and incidents and suggest that similar environmental and public safety benefits could be achieved by

[91] 2024 GHGI, Annex 3.6.

[92] PHMSA, "Pipe Replacement Background" (Apr. 8, 2024), https://www.phmsa.dot.gov/data-and-statistics/pipeline-replacement/pipeline-replacement-background (last accessed Sept. 4, 2024).

upgrading gas transmission and gas gathering pipelines made from materials known to leak. PHMSA and its predecessor agency, the Research and Special Programs Administration (RSPA), have identified replacement of cast-iron and bare-steel pipe as a policy priority for reducing gas distribution leaks and incidents for over two decades. Further, on November 15, 2021, the Bipartisan Infrastructure Law (Pub. L. 117-57) appropriated $200 million per year for 5 years with a $1 billion limit to establish PHMSA's Natural Gas Distribution Infrastructure Safety and Modernization Grants program, which provides grant funding to municipally- or community-owned gas distribution pipeline facilities for the purpose of repairing or replacing legacy pipeline facilities.[93]

Methane Emissions Data—Natural Gas Transmission and Storage

The GHGI estimates that, in 2022, natural gas transmission pipelines (excluding storage) emitted 1,088 kt of methane; however, the causes of those emissions are very different than the causes for distribution emissions. Leaks from natural gas transmission line pipe represent only 3.3 kt of net methane emissions from the transmission sector. As shown in the table below, vented and fugitive emissions (i.e., leaks) from natural gas transmission compressor stations and metering stations comprise a significant portion of total methane emissions from pipeline facilities. The GHGI data shown below for the natural gas transmission and storage segment reflects both onshore and offshore sources.

2024 GHG Inventory: 2022 Natural Gas Transmission Methane Emissions

[93] See PHMSA. "Natural Gas Distribution Infrastructure Safety and Modernization Grants" (May 30, 2024), https://www.phmsa.dot.gov/about-phmsa/working-phmsa/grants/pipeline/natural-gas-distribution-infrastructure-safety-and-modernization-grants (last accessed Aug. 29, 2024).

Source	Kt CH_4	Percentage of Total Sector Emissions
Pipeline Leaks	3.3	0.3
Pipeline Venting (including blowdowns and upset venting)	133.8	12.3
Station Venting (including blowdowns)	146.7	13.5
Dehydrator Venting	2.3	0.2
Flaring	0.5	0.0
Pneumatic Devices	31.2	2.9
Compressor Station Fugitive Emissions	588.5	54.1
Compressor Exhaust	181.8	16.7
Total	1,088.0	100
Note: Pipeline venting includes releases from ruptures and other reportable incidents.		

The table below shows emissions from compressor stations on natural gas transmission pipelines in additional detail. Emissions from generators include emissions from natural gas storage facilities dedicated to a compressor station.

2024 GHG Inventory: 2022 Natural Gas Transmission Compressor Station Methane Emissions

Source	Kt CH_4	Percentage of Total Sector Emissions
Fugitive Emissions	128.1	14.0
Reciprocating Compressor	322.7	35.2
Centrifugal Compressor (Wet Seals)	50.5	5.5
Centrifugal Compressor (Dry Seals)	87.1	9.5
Engine Exhaust	165.5	18.1
Turbine Exhaust	1.7	0.2
Generator Engines (inc. Storage)	14.6	1.6
Generator Turbine (inc. Storage)	0.004	0.0
Station Venting	146.7	16.0
Total	916.9	100

Additionally, the table below shows emissions from natural gas storage facilities.[94]

2024 GHG Inventory: 2022 Natural Gas Storage Methane Emissions

Source	Kt CH_4	Percentage of Total Sector Emissions
Station and Compressor Fugitive Emissions	24.5	7.7
Reciprocating Compressors	102.9	32.3
Storage Wells	11.1	3.5
Metering and Regulating (Transmission Interconnect)	75.0	23.5
Metering and Regulating (Farm Taps & Direct Sales)	17.4	5.5
Dehydrator Venting	4.8	1.5
Flaring	0.3	0.1
Engine Exhaust	24.1	7.5
Turbine Exhaust	0.2	0.1
Generators (inc. Transmission)	14.6	4.6
Pneumatic Devices	15.3	4.8
Station Venting	28.9	9.1
Total	319.0	100

Though the 2024 GHGI does not track relief and control device releases as a separate emissions source for natural gas transmission and storage facilities, PHMSA incident report data indicates that such releases are a significant contributor to methane emissions. A pressure relief device is designed to allow gas to escape from a pressurized system to protect the system from overpressurization. Relief devices and other pressure control devices are critical to the safe operation of a pipeline system when they function as intended. However, a poorly designed or poorly configured pressure relief device can result in releases of gas to the atmosphere larger

[94] The nature and use of tankage as storage incidental to the movement of gas by pipeline dictates whether storage facilities are pipeline facilities subject to the jurisdiction of 49 U.S.C 60101, *et seq*.

than strictly necessary for protecting pipeline integrity. Conversely, a relief device or control device that fails to release gas as designed or configured will not provide adequate protection from overpressurization and may rupture, presenting a hazard to public safety and the environment. Between 2010 and 2023, PHMSA incident report data yields that "malfunction of control/relief equipment," including control valves, relief valves, pressure regulators, and emergency shutdown device system failures,[95] was listed as the cause for 22 percent of incidents and 23 percent of the volume of unintentional gas emissions from reportable incidents on gas transmission pipelines. The vast majority of these incidents are reportable due to the unintentional emissions exceeding 3 MMCF, although these incidents are occasionally also reportable because repair costs or other monetary damages exceed the property damage criterion for the reporting requirements set out in § 191.3. Out of these 344 reported incidents, 130 involved the failure of a relief valve. The next most commonly involved component was emergency shutdown devices, which were involved in 75 incidents over this period.

Recent studies also suggest that current methane emissions data likely underestimates emissions from natural gas transmission and storage facilities. The emission factor for transmission pipeline leaks in the GHGI is based on the 1996 EPA/GRI report and is derived from the frequency of leak repairs reported on operators' annual reports to RSPA and self-reported leak measurements from distribution mains, both collected in 1991.[96] The authors of a

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[95] See PHMSA, Form F 7100.2, "Incident Report -Gas Transmission and Gathering System" at section G6 (May 2023). phmsa.dot.gov/forms/gas-transmission-and-gathering-annual-report-form-f-71002-1

[96] EPA & Gas Research Institute, Methane Emissions from the Natural Gas Industry, Volume 9: Underground Pipelines. (June 1996). Pgs. 38 and 46.

2015 study noted that the difficulty in accurately measuring abnormal "super-emitter" events from natural gas transmission and storage facilities using on-site measurements suggests that bottom-up methodologies underestimate emissions from "super-emitter" events, and consequently total emissions.[97] For example, the 1996 EPA/GRI report relied on limited RSPA incident report data that did not include a volumetric incident definition criterion as used under current PHMSA reporting requirements.[98] The RSPA incident report form in 1991 similarly did not require operators to provide an estimate of release volumes. While current methane emissions data attempts to address these data limitations by factoring in "super-emitter" estimates, this data gap remains a source of uncertainty for any type of point-in-time measurement.[99]

Similarly, certain infrequent but significant incidents at UNGSFs, such as the release of 86 billion cubic feet (BCF) of natural gas from the Aliso Canyon facility failure in 2015, the release of 6 BCF of natural gas from the Moss Bluff facility in 2004, and the release of 143 BCF of natural gas from the Yaggy storage field in 2001 demonstrate both the uncertainty in

[97] Zimmerle et al., "Methane Emissions from the Natural Gas Transmission and Storage System in the United States," 49 Environmental Science & Technology 9374 (July 21, 2015).

[98] See, e.g., RSPA Form F 7100.2 (Rev. 3 - 1984), "PHMSA Gas Transmission & Gathering Incident Data – mid 1984 to 2001", available at https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data (last accessed Jan. 4, 2023).

[99] See Alvarez et al., "Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain," Science 186, Table 1 (June 21, 2018) (finding that bottom-up quantifications of methane emissions may underestimate natural gas transmission and storage emissions by nearly 30% when compared with top-down quantifications).

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estimating methane emissions from UNGSFs and the potential for substantial methane emissions from such facilities.[100]

Methane Emissions Data—Gathering Pipelines

The GHGI estimates that natural gas gathering and boosting systems have estimated fugitive emissions from line pipe leaks that are much higher than for natural gas transmission systems. As shown in the table below, the GHGI estimates 96.3 kt of methane emissions caused by pipeline leaks from natural gas gathering and boosting systems (estimated at 393,049 miles in the GHGI)[101] compared with 3.3 kt for natural gas transmission systems (300,796 miles).

2024 GHG Inventory: 2022 Natural Gas Gathering and Boosting Methane Emissions

Source	Kt CH_4	Percentage of Total Sector Emissions
Combustion Slip	417.2	27.3
Compressors	314.1	20.6
Tanks	310.2	20.3
Pneumatic Devices	171.0	11.2
Pipeline Leaks	96.3	6.3
Yard Piping	101.8	6.7
Station Blowdowns	32.0	2.1
Dehydrator Vents and Leaks	42.7	2.8
Pneumatic Pumps	21.2	1.4
Pipeline Blowdowns	7.9	0.5
Flare Stacks	12.3	0.8
Separators	1.5	0.1
Acid Gas Removal Units	0.1	0.0
Total	1528.4	100
Note: Total includes Type R gas gathering pipelines and production operations not regulated under part 192.		

[100] PHMSA, "Pipeline Safety: Safe Operations of Underground Storage Facilities for Natural Gas," 81 FR 6334 (Feb. 5, 2016) (Advisory Bulletin ADB-2016-02).

[101] 2024 GHGI, Annex 36 Table 3.6-7.

Recent research also suggests that, as in the case of other gas pipeline facilities, current methane emissions data likely understate emissions from natural gas gathering pipelines. One study conducted in the New Mexico Permian Basin in 2022 estimated that emissions from natural gas production and gathering facilities in that region were 6.5 times larger than GHGI estimates.[102] The authors of that study estimated methane emissions using a comprehensive aerial survey spanning 35,923 square kilometers (which included over 15,000 kilometers of natural gas pipelines) over 115 flight days. This large sample size was intended to better capture infrequent "super-emitter" events, and the study found that 50 percent of observed emissions were attributable to large emissions sources with average methane emissions rates greater than 308 kilograms per hour. Studies in the past few years have suggested that leaks from gathering pipelines and compressor stations may be higher than previously understood. While GHGI emissions factors for those facilities have decreased over the time, studies aiming to improve gas gathering pipeline emissions factors like one conducted on the Utica Shale in 2020,[103] suggest that self-reported emissions information from GHGRP reporting (on which GHGI emissions data for gathering pipelines is based) may underestimate actual emissions rates..Any point-in-time measurement of methane emissions, particularly methodologies that use smaller sample areas,

[102] Chen et al., "Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey," 56 Environmental Science & Technology 4317 (Mar. 23, 2022) (finding that "[m]idstream assets were also a significant source [of emissions], with 29 ± 20 t/h [(metric tonnes per hour)] emitted from pipelines (including underground gas gathering pipelines) and 26 ± 16 t/h emitted from compressor stations without a well on site").

[103] Li et al., "Gathering Pipeline Methane Emissions in Utica Shale Using an Unmanned Aerial Vehicle and Ground-Based Mobile Sampling," Atmosphere 11(7) (July 5, 2020).

such as ground-based approaches, can miss large but infrequent events, thus underestimating total emissions when extrapolating beyond the sample area to an entire region.[104]

Methane Emissions Data—LNG Facilities

As shown in the tables below, the GHGI estimates that blowdowns account for 66 percent of methane emissions from LNG storage facilities and 43 percent of methane emissions from all LNG facilities.

2024 GHG Inventory: LNG Facilities 2022 Methane Emissions (Kt CH_4)

Source	Storage Facilities	Import and Export Terminals
Equipment Leaks, Compressors, Flares, etc.	3.4	3.5
Blowdowns	8.6	0.1
Engine Exhaust	1.0	0.9
Turbine Exhaust	0.0	2.6

Fugitive emissions represent approximately half of estimated methane emissions from LNG import and export terminals. While LNG facilities are often designed with boil-off gas recovery systems to avoid routine continuous venting of natural gas during operations, methane regularly escapes from LNG facilities through compressor rod packing and valve leakage, incomplete combustion during flaring, and other various process venting sources.[105] Similar to gas transmission facilities, additional emissions for LNG facilities are attributable to releases from relief devices and O&M-related venting. Likewise, fugitive emissions from gas treatment

[104] Chen et al., 2022, at 4321-22 ("[T]he clear impact of large emissions found by this study suggests that estimates from ground-based methane surveys may be underestimating total emissions by missing low-frequency, high-impact large emissions.").

[105] API, Compendium of Greenhouse Gas Emissions Methodologies for the Natural Gas and Oil Industry at 6-121 through 6-126 (Nov. 2021).

equipment at liquefaction plants are likely similar to those from comparable equipment on other pipeline or gas processing facilities.[106] Methane may also be lost to the atmosphere during pipe transfers of LNG to or from an LNG facility, whether through loading for transport or off-loading for storage or vaporization. Even if initially captured, boil-off gas and other fugitive emissions from LNG facilities may still be vented directly to the atmosphere without combustion during normal operation.[107] And, as with any pipe transporting natural gas, the pressurized piping that runs throughout LNG facilities is susceptible to integrity failures and other incidents,[108] including pipeline leaks that can precipitate explosions.[109] For example, Cheniere Energy, Inc. (Cheniere) reported that the Sabine Pass LNG terminal has approximately 40 miles of plant piping within its import facilities and an additional 285 miles of plant piping within its

[106] API, Compendium of Greenhouse Gas Emissions Methodologies for the Natural Gas and Oil Industry at 6-121 through 6-122 (Nov. 2021).

[107] API, Compendium of Greenhouse Gas Emissions Methodologies for the Natural Gas and Oil Industry at 6-123 (Nov. 2021). For example, boil-off gas may be vented if the vapor generation rate exceeds the capacity of the boil-off gas compressors or the re-liquefaction unit. API's compendium estimates typical losses at 0.05% of total tank volume per day when boil-off gas is vented from an LNG storage vessel. See also Soraghan & Lee, "LNG explosion shines light on 42-year-old gas rules" EnergyWire. (June 28, 2022), https://www.eenews.net/articles/lng-explosion-shines-light-on-42-year-old-gas-rules/ (noting that an LNG terminal had reported several natural gas releases to the state Department of Environmental Quality, including one release of 180,000 pounds of methane in January 2022).

[108] See, e.g., PHMSA, CPF No. 4-2022-051-NOPSO, "In the Matter of Freeport LNG Development LP: Notice of Proposed Safety Order" at 3 (June 30, 2022), (describing the LNG release and natural gas vapor cloud that resulted from the June 8, 2022 incident at the Quintana Island LNG facility, which may have been caused by the overpressure and rupture of a segment of LNG transfer line between the facility's LNG storage tank area and its dock facilities).

[109] See, e.g., "Algerian LNG Complex Explosion Caused by Gas Pipeline Leak," Oil & Gas Journal (Feb. 18, 2004). A gas pipeline leak was ultimately determined to be the cause of the Skikda, Algeria LNG terminal explosion on January 20, 2004, that killed 27 people, injured 74 others, and resulted in an estimated $800 million – $1 billion in damages to the Skikda port facilities, including the destruction of three of the LNG terminal's six liquefaction trains. See also Romero, "Algerian Explosion Stirs Foes of U.S. Gas Projects," New York Times (Feb. 12, 2004).

first four of six liquefaction trains,[110] and the operator of the Cameron LNG terminal reported approximately 255 miles of piping in their liquefaction project consisting of three liquefaction trains.[111] Freeport LNG similarly reported that its liquefaction project's pre-treatment and three liquefaction trains included approximately 192 miles of plant piping, providing ample opportunities for methane to escape during normal and emergency operations.

Emissions for LNG facilities have proven difficult to estimate due to the limited availability of accurate, complete emissions data, with insufficient differentiation between intentional and fugitive emissions.[112] Bottom-up methodologies for estimating LNG emissions typically use generalized emissions factors averaged across the entire sector despite significant differences between suppliers and each step of the supply chain.[113] Emissions estimates using this approach may apply a single emissions factor to all types of LNG facilities, even though the wave of recently built LNG export terminals could have little in common with an LNG peak shaver or storage facility. Developing accurate emissions estimates is also hampered by selection bias. Specifically, the EPA currently uses data reported in accordance with 40 CFR part 98, subpart W (i.e., the GHGRP) to develop GHGI emissions factors for LNG facilities (except for LNG storage facility blowdowns). However, operators of LNG facilities need only report emissions under 40 CFR part 98, subpart W, if total emissions reach the reporting threshold of

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[110] Cheniere. "Cheniere Energy Analyst/Investor Day." (Apr. 2014). Pgs. 12-13.

[111] Cameron LNG. https://cameronlng.com/lng-facility/economic-impact/. (last accessed Sept. 4, 2024)

[112] Oxford Institute for Energy Studies, Measurement, Reporting, and Verification of Methane Emissions from Natural Gas and LNG Trade: Creating Transparent and Credible Frameworks at 51 (Jan. 2022).

[113] See Roman-White et al., "LNG Supply Chains: A Supplier-Specific Life-Cycle Assessment for Improved Emission Accounting," ACS Sustainable Chemistry & Engineering at 10857, 10861 (2021).

25,000 metric tons of CO_2 equivalent per year. Many LNG storage facilities fall under that threshold, introducing uncertainty into the aggregate emissions calculated using only a subset of LNG storage facilities.[114]

Further, even among those LNG facilities that report their emissions to the EPA, there is a potential for great variation in the emissions reported within and across reporting years due to small sample sizes: given that only 5 storage facilities and 11 import and export facilities report emissions to the EPA as of August 2023,[115] the resulting methane emissions estimates are susceptible to substantial year-to-year fluctuations and limit the predictive value of such estimates for subsequent years.[116] Lastly, up until 2025, operators of LNG storage facilities were not required to report LNG storage blowdown emissions under the GHGRP[117]—instead, GHGI estimates for LNG storage blowdown emissions consist of generalized data based on a 1996 study of blowdown emissions on gas transmission compressor stations and UNGSFs.[118]

[114] EPA, Memorandum, "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017: Updates to Liquefied Natural Gas Segment" at 2-3 (Apr. 2019). While EPA identified between 94-98 LNG storage facilities as active each year from 2011-2017, only 8 such facilities reported emissions under Subpart W during that timeframe.

[115] See EPA, "GHGRP Petroleum and Natural Gas Systems," https://www.epa.gov/ghgreporting/ghgrp-petroleum-and-natural-gas-systems#emissions-table (last accessed Aug. 29, 2024).

[116] For example, in 2016, one LNG storage facility was responsible for more than 82 percent of all LNG storage facility methane emissions and one LNG import terminal was responsible for more than 95 percent of all LNG terminal methane emissions reported to EPA under Subpart W. EPA, Memorandum, "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017: Updates to Liquefied Natural Gas Segment" at 3-8 & Tables 5, 8 (April 2019).

[117] Effective January 1, 2025, LNG storage facilities are required to report emissions from blowdowns to the GHGRP (89 FR 42087)

[118] EPA, Memorandum, "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017: Updates to Liquefied Natural Gas Segment" at 1 (April 2019).

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4. Public Safety Risks of Emissions from Gas Pipeline Facilities

Emissions from gas pipelines also present significant hazards to public safety,[119] primarily through the ignition of accumulated gas. This risk is especially prominent in higher-population areas, such as Class 3 and Class 4 locations, where buildings intended for human occupancy are more prevalent and it can be harder to evacuate in the event of a rupture. However, risks to individual safety can also arise wherever gas pipeline emissions accumulate in confined spaces, such as asphyxiation.

Leaks of any type can degrade into catastrophic failures—sometimes referred to as the "leak-before-break" concept[120]—with public safety consequences of much greater magnitude. If permitted to continue leaking indefinitely without repair or monitoring, even the smallest leak has the potential to degrade and lead to a greater public safety impact. And leaks from part 192-regulated pipeline facilities that transport toxic or corrosive gases can have serious public safety consequences apart from explosions and ruptures.

Gas gathering pipeline leaks present a unique set of public safety risks. Unprocessed natural gas transported by gathering pipelines typically contains significant quantities of volatile organic compounds (VOC) and hazardous air pollutants (HAPs) such as benzene (a known carcinogen). As discussed in further detail in the RIA, VOCs and HAPs pose risks to individuals

[119] PHMSA discusses in this section only direct public safety consequences of leaks; however (as explained in section II.B), leaks and other releases from gas pipelines can also have second-order public safety impacts resulting from climate change-induced natural force damage and equipment malfunction.

[120] See, e.g., Wilkowski, "Leak-Before-Break, What Does It Really Mean?" 122 Journal of Pressure Vessel Technology 267 (Aug. 2000); Zhang, et al., "Paper: Preventive Leak Detection for High Pressure Gas Transmission Networks," AAAI 2017 (2017); see also GPTC Guide appendix G-192-11 table 3c, recommending that grade 3 leaks be reevaluated within 15 months or during the next required leakage survey.

from long-term adverse health effects. VOC emissions are precursors to ozone, and to a lesser extent, fine particulate matter ($PM_{2.5}$). The inhalation of both ambient ozone and $PM_{2.5}$ are associated with adverse health effects on individuals, including respiratory morbidity, such as asthma attacks, hospital and emergency department visits, lost school days, and premature respiratory mortality. HAPs contained in unprocessed natural gas include several substances that are known or suspected carcinogens, including benzene, formaldehyde, toluene, xylenes, and ethylbenzene. Benzene and formaldehyde are known human carcinogens, and ethylbenzene has been identified as possibly carcinogenic in humans. Chronic (long-term) inhalation of benzene can result in several adverse non-cancer health effects, including arrested development of blood cells, anemia, leukopenia, thrombocytopenia, and aplastic anemia. Acute (short-term) exposure to benzene vapors has been reported to cause negative respiratory effects. Formaldehyde inhalation exposure also causes a range of non-cancer health effects, including irritation of the nose, eyes, and throat. Repeated exposure to formaldehyde vapors can cause respiratory tract irritation, chronic bronchitis, and nasal epithelial lesions. There is evidence that formaldehyde may also increase the risk of asthma and chronic bronchitis in children. Inhalation of toluene, mixed xylenes, and ethylbenzene can have neurological, respiratory, and gastrointestinal effects, among others, with chronic exposure to toluene potentially leading to developmental effects, such as central nervous system dysfunction, attention deficits, and other anomalies. Further, corrosives in unprocessed natural gas can accelerate corrosion in the vicinity of leaks, thereby increasing the risk of a catastrophic failure. Natural gas gathering pipelines are often located in the vicinity of socially vulnerable populations, compounding the harm these leaks can cause to the public.[121]

C. Limits of Federal and State Regulations

In sections II.D and II.E of the NPRM, PHMSA described how Federal and State pipeline safety requirements have fallen short with respect to gas pipeline LDAR, intentional methane releases, and reporting of leaks and other gas releases. Federal leak repair requirements were historically focused on leaks the operator deemed "hazardous" to people or property without providing any enforceable criteria for what constitutes a hazardous leak and largely ignored the environmental risks posed by gas pipeline leaks, no matter how significant. Additionally, until this rulemaking, the PSR did not require operators to use leak detection equipment for the majority of leak surveys on gas transmission lines and did not set minimum standards for the performance of leak detection equipment in those limited circumstances where operators were required to use such equipment. These shortcomings allowed leaks of methane and other gases from gas gathering, transmission, and distribution pipeline facilities to continue undetected and unrepaired for extended periods of time and failed to leverage the emissions reduction potential of commercially available ALD technologies and practices within integrated ALDPs. This historical approach also missed opportunities for operators to promptly identify and remediate leaks from gas pipelines that could have developed into catastrophic incidents.

[121] Emanuel et al., "Natural Gas Gathering and Transmission Pipelines and Social Vulnerability in the United States," 5 GeoHealth (June 2021) (concluding that natural gas gathering and transmission infrastructure is disproportionately sited in socially-vulnerable communities).

1. Historical PHMSA Regulations Pertinent to Unintentional Releases of Methane and Other Gases

PHMSA's historical regulatory requirements relating to gas pipeline leak detection, repair, maintenance, and reporting reflected a focus on public safety risks from the ignition of large-volume releases or accumulated gas while treating risks to the environment as less important. PHMSA's prior maintenance requirements at 49 CFR part 192, subpart M, explicitly required operators to identify, repair, or report only a subset of unintentional releases from gas pipelines: namely those unintentional releases thought to create an "existing or probable hazard" to public safety.[122] Those maintenance requirements in the subpart M regulations also did not include explicit requirements for operator to replace or remediate pipes known to leak based on material, design, or past O&M history.[123] PHMSA's integrity management (IM) regulations at 49 CFR part 192, subparts O and P (for gas transmission and gas distribution pipelines, respectively) allow considerable discretion in allowing operators to determine which leaks merit repairs and the timing of those repairs. PHMSA's prior reporting requirements at 49 CFR part 191 similarly did not capture any information on intentional releases or leaks that operators discovered but did not repair.

[122] See, for example, the definition of term "hazardous leak" in § 192.1001.

[123] An exception is that part 192, subpart M acknowledges cast-iron piping's susceptibility to leakage and contains provisions focused on a single mechanism (graphitization-derived corrosion) for development of leaks, and then only after indicia of that mechanism have emerged. Specifically, § 192.489(a) requires replacement of each segment of cast iron or ductile iron pipe with general graphitization (a type of corrosion) that could cause a fracture or leak. Section 192.489(b) similarly requires replacement, repair, or internal sealing for localized graphitization on cast and ductile iron pipeline segments that could result in leakage.

Gas Pipelines

49 CFR part 192, subpart M, historically contained minimum maintenance requirements for gas gathering, transmission, and distribution pipelines.[124] Gas transmission (§ 192.706), distribution (§ 192.723), offshore gas gathering, and Type A, Type B, and certain Type C gathering (§§ 192.9 and 192.706) pipeline operators were required to perform periodic leak surveys. When leaks were discovered, operators considered both the leak's severity and the operating conditions of the pipeline to determine whether and when to perform a repair. Section 192.703(c) broadly required operators to repair all "hazardous leaks […] promptly." However, subpart M neither defined a "hazardous" leak nor provided guidance on what constitutes a "prompt" repair of such leaks. Although § 192.1001 describes a "hazardous leak" in terms of an existing or probable hazard to persons or property, and not the environment, that regulatory definition applies only to the gas distribution IM requirements in 49 CFR part 192, subpart P. The general repair requirement at § 192.703(c) was also inapplicable to most Type C gas gathering pipelines.[125]

[124] Certain part 192 regulations will be revised on codification of a recent PHMSA rulemaking that will become effective on May 24, 2023. See PHMSA, "Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments–Final Rule," 87 FR 52224 (Aug. 24, 2022) (RIN2 Final Rule). PHMSA's references to part 192 within this final rule—including the proposed amended regulatory text at its conclusion—reflect the regulatory text and organization as amended by the RIN2 Final Rule unless otherwise noted. The RIN2 Final Rule contains enhanced repair criteria that can affect leak repairs, but the requirements are generally directed toward phenomena (cracking, corrosion-induced metal loss, dents) distinct from the detection, grading, and repair of all leaks per this final rule.

[125] Only ca. 20,000 miles of the ca. 91,000 miles of Type C gas gathering pipelines are subject to § 192.703(c). "Regulatory Impact Analysis for Gas Gathering Final Rule" at 11, 15 (Nov. 15, 2021) PHMSA-2011-0023-0488.

Previous 49 CFR part 191 reporting requirements similarly reflected PHMSA's historical focus on public safety risks from the ignition of large-volume releases or accumulated gas.[126] Incident reports for gas distribution (Form F 7100.1), transmission and part-192 regulated gathering (Form F 7100.2), and Type R gathering pipelines (Form F 7100.2.2) provided limited information regarding unintentional releases, as operators only needed to report unintentional releases of at least 3 MMCF. And while annual reports for gas distribution (Form F 7100.1-1), transmission and part-192 regulated gathering (Form F 7100.2-1), and Type R gathering pipelines (Form F 7100.2-3) included information on the number of leaks repaired in the preceding calendar year, the instructions for those annual report forms expressly excluded reporting of repairs on a broad category of leaks: releases that can be corrected by "lubrication, adjustment, or tightening" were not considered "leaks" for the annual reporting of repairs.[127] The instructions for annual reports, other than for gas distribution pipelines, also did not require operators to report the repairs of any leaks other than leaks that are hazardous, and the instructions for all annual report forms characterized leaks as "hazardous" with respect to public safety, omitting mention of risks to the environment. Further, none of PHMSA's annual reports required operators to submit information on the total number of leaks detected in the reporting

[126] PHMSA annual and incident forms and instructions discussed in this paragraph can be found on PHMSA's website at https://www.phmsa.dot.gov/forms/operator-reports-submitted-phmsa-forms-and-instructions. https://www.phmsa.dot.gov/forms/operator-reports-submitted-phmsa-forms-and-instructions.

[127] PHMSA annual reporting requirements for part 193-regulated LNG facilities contain a similar exception from leak reporting requirements. *See* PHMSA, Form 7300.1-3, "Annual Report Form for Liquefied Natural Gas Facilities (Oct. 2014); PHMSA, Instructions for Form 7300.1-3 at 4 (Oct. 2014) (stating that "a non-hazardous release that can be eliminated by lubrication, adjustment, or tightening is not a leak").

period, the total of all unrepaired leaks, or the estimated emissions associated with leaks during the reporting period.

Part 192-Regulated Gas Gathering Pipelines

Prior to this rulemaking, operators of offshore gas gathering, Type A, Type B, and certain Type C gathering pipelines were required to comply with the leak survey requirements applicable to gas transmission pipelines and repair any hazardous leaks detected per 49 CFR 192.706 and 192.703, respectively. However, most Type C gathering pipelines—specifically, those with an outer diameter between 8.625 and 16 inches that are not located near an occupied building—were, pursuant to § 192.9(f)(1), not subject to any part 192 leak survey and repair requirements, whether for "hazardous" leaks or any other leaks. Additionally, only offshore gas gathering and Type A gathering pipelines were subject to other subpart M maintenance requirements, including right-of-way patrols per § 192.705, general transmission pipeline requirements for making permanent or temporary repairs per § 192.711, and recordkeeping per § 192.709. Operators of Type B and Type C gathering pipelines needed only to comply with the specific requirements listed in §§ 192.9(d) and (e), which did not include patrol, repair, and recordkeeping requirements.

Gas Transmission Pipelines

All gas transmission pipelines have been historically subject to maintenance requirements at 49 CFR part 192, subpart M. Section 192.706 required gas transmission operators to perform leak surveys on most gas transmission pipelines at least once every calendar year. However, that provision did not require operators to use leak detection equipment for those leak surveys. Leak detection equipment was only required in accordance with prior § 192.625 if a gas transmission pipeline was not odorized and the pipeline was located in a Class 3 or Class 4 location; otherwise, operators were allowed to perform these leak surveys by using human senses, such as the visual observation of dead vegetation or blowing debris. Operators that were required to conduct a leak survey with leak detection equipment had to do so at least twice each year in Class 3 locations and at least four times each calendar year in Class 4 locations.

In addition to leak surveys, previous § 192.705 required operators of gas transmission pipelines to have a patrolling program to monitor conditions on and adjacent to pipeline rights-of-way. These patrols are visual surveys, commonly performed using aircraft, and are intended to find leaks and other conditions affecting the safety and operation of the pipeline. Patrols commonly identify potential or current pipeline integrity threats caused by external forces and activities, including construction, excavation, blasting, earth movements, and flooding. Information gathered from these patrols can prevent further damage to the pipeline or encourage operators to target leak surveys or integrity assessments to locations that may have been damaged. This can prevent leaks, potentially fatal incidents, and damages that could result in shutdowns and maintenance-related releases of methane and other gases to the atmosphere. For example, if an operator spots construction activity along a pipeline, they can dispatch personnel to observe construction to minimize the risk of excavation-related damage to the pipeline. According to reports submitted to PHMSA, excavation damage is a leading cause of incidents that result in injuries and fatalities and pipeline breaks (which often result in the release of large volumes of gas).

The patrol frequency, in accordance with this requirement, depends on the class location of the pipeline, the pipeline's diameter, the operating pressure of the pipeline, and other relevant factors, including weather and terrain. Gas transmission pipeline operators were required to perform patrols at least four times each calendar year in Class 4 locations, at least twice each calendar year in Class 3 locations, and at least once each calendar year in Class 1 and Class 2 locations. If the pipeline was located at a highway or railroad crossing in a Class 1 or Class 2 location, operators were required to follow an increased patrol frequency of at least twice each calendar year. In Class 3 locations, the minimum patrol frequency at highway and railroad crossings was four times each calendar year.

As explained above, § 192.703(c) required all transmission operators to repair leaks that were "hazardous" to public safety "promptly," but the regulations contained few guidelines as to what "promptly" meant. Repair requirements at § 192.711 require that operators take immediate temporary measures (such as temporary repairs or a temporary reduction in operating pressure) when leaks occur that impair the serviceability of a steel transmission pipeline operating above 40 percent of SMYS if a permanent repair is not feasible at the time of discovery.
Section 192.711(b) was revised in 2022 by the final rule titled "Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments"[128] to require that operators of gathering lines and offshore transmission lines make permanent repairs "as soon as feasible" for those pipelines not located in HCAs, and follow the repair schedule set forth at § 192.714 for

[128] 87 FR 52224 (August 24, 2022).

onshore transmission lines also not located in HCAs. For pipelines located in HCAs that are covered under 49 CFR part 192, subpart O, that rule requires operators to remediate the condition in accordance with § 192.933(d).[129] Like the historical general repair requirement in § 192.703, these requirements frame leak repair obligations in terms of public safety risks and, in cases of gathering lines and offshore transmission lines, use ambiguous language (i.e., "as soon as feasible") to describe the timing of any repair obligations. In recognition of this regulatory gap, PHMSA has referenced the GPTC Guide in guidance and letters of interpretation on how operators should comply with these provisions of part 192.[130]

Gas Distribution Pipelines

Gas distribution pipelines are subject to select 49 CFR part 192, subpart M, maintenance requirements. Section 192.721 requires operators to patrol distribution mains at frequencies that consider the severity of the conditions that would cause failure or leakage and the consequent hazard to public safety. Operators must patrol distribution mains subject to physical movement or external loading that could cause failure or leakage at least twice each calendar year if located

[129] The final rule introduced a new § 192.714 referencing ASME/ANSI B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines at section 7, Figure 4 (Jan. 14, 2005)). However, those repair schedules—which are intended for "anomalies and defects" consisting of dents, corrosion metal loss, and cracking rather than leaks—contemplate that some repairs may not be required for years. The final rule did not disturb the existing requirement to effectuate permanent repairs "as soon as feasible" for other part 192-regulated gas pipelines not subject to subpart O IM requirements.

[130] See, e.g., PHMSA, "Distribution Integrity Management: Guidance for Master Meter and Small Liquefied Petroleum Gas Pipeline Operators" (2013) at 2 (directing larger distribution pipeline operators to refer to GPTC guidelines); PHMSA, Interpretation Response Letter No. PI-93-009 (Feb. 11, 1993) (recommending public stakeholder consult the GPTC Guide for further determination of instruments and techniques to be used in certain leak detection activities); see also PHMSA, Interpretation Response Letter No. PI-99-0105 (Dec. 1, 1999) (stating that the GPTC Guide "is a document endorsed by us which contains information and some methods to assist the gas pipeline operator in complying with the regulations contained in 49 CFR part 192").

outside of business districts, and at least four times every calendar year if located within business districts. Distribution leak survey requirements are defined in § 192.723. In business districts, operators must conduct leak surveys of distribution pipelines with leak detection equipment at least once every calendar year. These surveys must include testing the atmosphere in utility manholes, at cracks in the pavement and sidewalks, and at other locations, providing several opportunities for operators to find leaks. Outside of business districts, operators were historically required to perform leak surveys using leak detection equipment as frequently as necessary but not less than once every 5 calendar years. Gas distribution operators were subject to repair requirements for hazardous leaks at § 192.703, but that requirement provided no specific guidance on repair timelines and failed to mention or consider environmental risks.

2. Shortcomings of Current PHMSA Regulations in Addressing Unintentional Releases from Gas Pipelines

PHMSA regulations pertinent to leaks from gas pipelines have historically focused on risks to public safety posed by the ignition of large-volume releases or accumulated gas from gas pipeline facilities—an approach that is vital for protecting public safety but that foregoes opportunities to address environmental harms, including the contribution of methane emissions to climate change. This approach has proven unsuccessful in the timely identification and remediation of leaks that can have a substantial impact on the environment or that can even evolve into incidents posing catastrophic risks to public safety.

As explained above, historical 49 CFR part 192, subpart M, maintenance requirements contained only a single repair requirement specific to leaks, which was applicable only to some part 192-regulated gas gathering, transmission, and distribution pipelines: § 192.703(c)'s requirement that operators must repair "hazardous leaks" "promptly." However, neither "hazardous leaks" nor "promptly" were defined in subpart M. Rather, what other limited evidence there was in PHMSA regulations elaborating on the meaning of "hazardous leak" pertained either to entirely different elements of part 192, specifically, the § 192.1001 definition of "hazardous leak" within DIMP requirements in subpart P, or part 191 reporting requirements.[131] Both of these regulatory provisions describe "hazardous leak" with respect to potential or present risks to public safety; they are silent regarding risks to the environment. No historical provision in part 192 required operators to repair leaks to protect the environment.

Similarly, 49 CFR part 192, subpart M, historically did not elaborate on the requirement that all hazardous leaks be repaired "promptly" and did not explicitly require operators to consider environmental consequences. Section 192.711 allows operators to repair hazardous leaks and other conditions as soon as feasible for non-IM repairs pertaining to gathering lines and offshore transmission lines, and as prescribed by §§ 192.714 and 192.933(d) for onshore transmission repairs in non-HCAs and for IM repairs, respectively.

49 CFR part 192 historically did not specify remote or continuous monitoring for pipeline leaks apart from a limited requirement pertaining to the detection of ruptures, rather than leaks, on certain new gas transmission pipelines where operators have installed "rupture-mitigation

[131] See, e.g., PHMSA, Form F 7100.1-1 Instructions (May 2021) (defining hazardous leaks as those representing an "existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous"). The instructions for annual report forms for other gas pipeline facilities contain similar language.

valves."[132] Frequencies of leak surveys and patrol requirements at §§ 192.705 and 192.706, respectively, were generally keyed to the location of the pipeline and the presence of nearby populations—proxies for risks to public safety but not the environment. Consequently, operators of the majority of part 192-regulated gas transmission pipeline mileage and some part 192-regulated, onshore gathering pipeline mileage in the United States (in particular, Types A and B gathering pipelines in more populated areas, and a minority of Type C lines[133]) were long required only to conduct annual leak surveys, with as long as 15 months between surveys. The patrolling requirements for distribution systems are specified in § 192.721 and the leak survey requirements for distribution systems are specified in § 192.723. Operators were required to perform leak surveys on gas distribution pipelines outside of business districts once every 5 years. Similarly, PHMSA regulations at subpart M allowed gas transmission and select part 192-regulated gathering pipeline operators to perform right-of-way patrols only once a year, if at all. Finally, leak surveys on gas distribution pipelines inside business districts were required at least once a year.

49 CFR part 192, subpart M, maintenance requirements similarly lacked specific LDAR standards and failed to adequately address risks to the environment. Subpart M regulations were silent on the specific technologies or equipment operators should employ in their leak detection surveys. For example, operators were required to perform leak surveys on gas distribution lines,

[132] PHMSA, "Pipeline Safety: Requirement of Valve Installation and Minimum Rupture Detection Standards – Final Rule," 87 FR 20940 at p. 20985 (Apr. 8, 2022) (introducing a new § 192.636).

[133] Only ca. 20,000 miles of the ca. 91,000 miles of Type C gas gathering pipelines are subject to § 192.706 leakage survey requirements. "Regulatory Impact Analysis for Gas Gathering Final Rule" at 11, 15 (Nov. 15, 2021), PHMSA-2011-0023-0488.

certain regulated gathering lines, and unodorized transmission pipelines in Class 3 and Class 4 locations using leak detection equipment, but part 192 neither required particular technologies, nor established performance standards for leak detection equipment. Previously, operators were permitted to perform patrols of pipeline rights-of-way and leak surveys on odorized gas transmission pipelines and gas transmission pipelines in Class 1 and Class 2 locations relying entirely on human senses, such as smell or sight, which are imprecise and substantially limited in their effectiveness. Evidence of a leak detectible by human senses includes dead vegetation caused by natural gas displacing oxygen in the soil, blowing soil, bubbling water, or noise. However, it may take a long time for evidence of a gas leak on vegetation to appear visibly from the air. Further, the reliability of vegetation surveys is inconsistent and depends heavily on soil and climate conditions, the characteristics of the vegetation, the time of year, and other factors. For example, the impacts of gas leaks on vegetation may not be visible during seasonal or climate conditions that produce dead vegetation, and in some soil conditions, gas can temporarily increase vegetation growth. Finally, vegetation surveys are ineffective in areas with no or sparse vegetation, such as paved areas, particularly rocky areas, or deserts.

Additionally, PHMSA's IM regulations do not require operators identify and remediate all leaks. PHMSA's IM regulations apply to about 7 percent of gas transmission pipelines,[134] and no part 192-regulated gathering pipelines, even Types A and C gathering pipelines with

[134] The effectiveness of its IM regulations for gas transmission pipelines at subpart O relies on operators' identification that those requirements apply—which is not a given. See NTSB, Pipeline Accident Brief 13-01, "Rupture of Florida Gas Transmission Pipeline and Release of Natural Gas" (Aug. 13, 2013) (finding that a gas transmission pipeline operator's exclusion of a segment from its IM plan due to mischaracterization of a Class 1 location contributed to a subsequent rupture).

operating characteristics and threats to public safety and the environment comparable to transmission lines,[135] are subject to any IM requirements. The IM requirements in the PSR also reflect a historical focus on identifying, preventing, and remediating risks to public safety from large-volume releases or accumulated gas rather than environmental harms. While the gas transmission IM regulations obligate certain transmission operators to find and eliminate pipeline anomalies posing risks to public safety, those regulations do not require operators to repair all discovered leaks and allow for substantial delay in operators evaluating and subsequently repairing leaks that operators consider, at their discretion, not to pose acute public safety risks. The DIMP regulations require gas distribution pipeline operators to have an "effective leak management program," but those regulations provide few standards regarding what constitutes an "effective" program and can instead give considerable deference to an operator's discretion regarding which leaks are repaired and when. Further, neither subparts O nor P of 49 CFR part 192 require operator IM plans to consider replacing or remediating pipe as a preventative or mitigative measure for pipe materials known to leak, despite data demonstrating that cast-iron, wrought-iron, unprotected steel, and certain plastic pipelines are more susceptible to leaks and other losses of pipeline integrity. PHMSA's IM regulations are also not designed to address leaks with low release rates that persist for a long period of time, which can make significant contributions to climate change.

PHMSA reporting requirements also historically reflected a narrow focus on public safety risks rather than environmental harms, such as the contribution of methane leaks to

[135] See Gas Gathering Final Rule, 86 FR at 63266 at pp. 63266-8, 63278 – 79 and 63282 – 84. (November 15, 2021).

climate change, or environmental degradation from the release of other flammable, toxic, or corrosive gases. Incident reporting criteria were expressed in terms of personal injury, commercial harm, property damage, or minimum release volumes that, at 3 MMCF,[136] were far too high to capture any but the largest unintentional leaks from pipeline facilities. Although annual reports operators submit to PHMSA contain information on all leaks repaired each year, the instructions for those annual reports explicitly discouraged operators to report leaks that could be eliminated by "lubrication, adjustment or tightening" on the narrow presumption that such releases were not necessarily hazardous from a public safety perspective. Operators were also not required to submit in their annual reports the total number of leaks—of any type—detected in the reporting period, the number of outstanding unrepaired leaks from year-to-year, or the estimated emission volumes from any category of detected leaks.

3. Consequences of Delayed Repair and Prolonged Releases from Leaks on Gas Pipelines

The shortcomings of the historic regulations pertaining to LDAR described above are not abstract risks; prior to this rulemaking, operators allowed leaks from gas pipelines to emit methane and other gases for extended periods of time,[137] thereby threatening the environment as well as public safety and human health.

The historic regulations for leak detection and patrol frequencies provided extended time in which leaks could develop and worsen, thereby resulting in prolonged methane and other

[136] This number corresponds to a volumetric release rate of 340 cubic feet per hour (CFH) or more over a 1-year period.

[137] See PHMSA accident report data; https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data.

emissions to the atmosphere. Infrequent leak detection and patrol requirements also produced increased public safety risks. PHMSA's regulations have long recognized the safety risk associated with the potential ignition of leaks, as evidenced by heightened leak surveying and maintenance requirements throughout 49 CFR part 192 for pipelines in Class 3 or Class 4 locations where buildings intended for human occupancy are more prevalent, as well as requirements to prevent the accumulation of gas in confined spaces (*see,* §§ 192.167(c)(2), 192.353(c), 192.355(b)(2), and 192.361(e)(3)). However, leaks on gas pipelines that do not ignite are also public safety risks, as leaks of toxic or corrosive gases can have serious public safety consequences, and leaks of any type can degrade into catastrophic failures—sometimes referred to as the "leak-before-break" concept.[138] Additionally, the historical absence of baseline leak detection equipment technology requirements for operators conducting leakage surveys also inhibited timely opportunities for operators to identify, evaluate, and remediate leaks. The absence of prescriptive repair criteria and mandatory repair schedules for all leaks has compounded the delays and methodological shortcomings in operators identifying leaks. And PHMSA's limited historic reporting requirements for leaks from all types of gas pipeline facilities complicated the agency's ability to identify systemic pipeline integrity issues and support enforcement actions against specific operators.

[138] See, e.g., Wilkowski, "Leak-Before-Break, What Does It Really Mean?" 122 Journal of Pressure Vessel Technology 267 (Aug. 2000); Zhang, et al., "Paper: Preventive Leak Detection for High Pressure Gas Transmission Networks," AAAI 2017 (2017); see also GPTC Guide appendix G-192-11 table 3c, recommending that grade 3 leaks be reevaluated within 15 months or during the next required leakage survey.

PHMSA further estimates that, due to those historic limitations in its regulatory regime, thousands of leaks persist across part 192-regulated gas pipelines. With respect to gas distribution pipelines, PHMSA annual report data between 2010 and 2023 yields roughly the same per-mile, nationwide averages of repairs of all leaks (0.230 leaks repaired/mile in 2010 and 0.214 in 2023) and repairs of hazardous leaks (0.089 in 2010 and 0.085 in 2023). PHMSA assumes that the average per-mile rate at which new leaks are created (when controlled for material type) remains constant, suggesting either that (1) operators may not be reporting to PHMSA a significant number of leak repairs on their gas distribution pipelines, (2) operators are not discovering or repairing a significant number of leaks on their gas distribution pipelines, or (3) regulatory requirements and operator repair practices have not yielded improvements in reducing the frequency of leak repairs or have failed to yield improvements in leak identification on gas distribution pipelines for roughly a decade. PHMSA annual report data totaled 504,212 leak repairs reported on operators' annual reports in 2023 alone, a figure which does not include leaks that are not scheduled for repair at all. Forty-five percent of leaks reported to PHMSA were attributable to causes that progressed over time (e.g., corrosion failure, equipment failure, and material failure), which may have been discovered earlier through more frequent leakage surveys, patrols, and repair practices.

Data from States employing the three-tiered GPTC Guide leak grading framework (discussed in section II.C.4 and II.D) for gas distribution pipeline facilities demonstrates that most leaks on distribution main and service pipelines that are identified by operators are not "hazardous leaks" and are therefore not subject to PHMSA repair requirements and can persist for extended periods before repair. By way of example, the 2023 Pipeline Safety Performance Measures Report from New York State reports that, out of 12,789 leaks discovered on main and service pipelines by 11 natural gas local distribution companies in 2023, and with these operators using New York State requirements similar to the GPTC Guide criteria, 4,770 (37.3 percent) were grade 1 leaks that approximate to "hazardous leaks" under PHMSA repair requirements in § 192.703(c), while an additional 2,453 (19.2 percent) were grade 2 leaks, and 5,566 (43.5 percent) were grade 3 leaks.[139] New York State has adopted repair deadlines mirroring those in the GPTC Guide for grade 2 leaks (12 months or 6 months, depending on the potential hazard, see 16 NYCRR 255.813-255.815).[140] However, neither the GPTC Guide nor New York State regulations, as of June 2024, require operators repair grade 3 leaks, resulting in a backlog of over 6,000 outstanding unrepaired leaks in 2023 in the State of New York.[141] Each of these unrepaired leaks will continue to release methane or other gases to the atmosphere until remediated, and each could increase in size between patrols or leak surveys. Minority populations and other disadvantaged communities often bear the brunt of unrepaired leaks on

[139] State of New York Department of Public Service, Case 24-G-0145, "2023 Pipeline Safety Performance Measures Report" (June 20, 2024), https://dps.ny.gov/nys-pipeline-safety-reports-and-orders. Note that New York leak classification requirements use the term "types" rather than "grades," however they are conceptually identical.

[140] The unofficial text of the New York Codes, Rules, and Regulations is available from the New York State Department of State via Thomson Reuters at https://govt.westlaw.com/nycrr/Browse/Home/NewYork/UnofficialNewYorkCodesRulesandRegulations?guid=I1092e460ba3811dd9496ee88430c6cd4&originationContext=documenttoc&transitionType=Default&contextData=(sc.Default)

[141] State of New York Department of Public Service, Case 24-G-0145), "2023 Pipeline Safety Performance Measures Report" at Appendix K (June 20, 2024), https://dps.ny.gov/nys-pipeline-safety-reports-and-orders.

those gas distribution systems.[142] The IM regulations at 49 CFR part 192, subpart P, have proven insufficient to prevent leaks, as the majority of gas distribution pipelines, including those in the New York data described above, are subject to DIMP regulations.

The number of leaks from gas transmission pipelines are also significant. A review of PHMSA incident data yields that over 635 of the 1,582 incidents (roughly 40 percent) reported by gas transmission operators between 2010 and 2023 involved leaks.[143] As discussed previously, PHMSA's IM regulations at 49 CFR part 192, subpart O, provide for insufficient prevention of leaks. Further, incident reports on gas transmission pipelines show that many leaks on transmission lines were either identified during leak surveys or patrols or were attributed to causes that could have been exacerbated over time. PHMSA therefore expects that more frequent patrols and leak surveys on transmission lines and prompt remediation would result in earlier detection and the potential avoidance of leak degradations that would lead to incidents.

Annual report data similarly suggests there are a large number of leaks on gas transmission pipelines and that there is potential value in bolstering the gas transmission LDAR requirements to promptly identify and remediate those leaks. In annual reports for calendar year (CY) 2023, gas transmission operators reported repairing 1,066 leaks on 296,684 miles of

[142] Luna et al., "An Environmental Justice Analysis of Distribution-Level Natural Gas Leaks in Massachusetts, USA," 162 Energy Policy 112778 (2022). This study of the distribution of gas leaks reported to the Massachusetts Department of Public Utilities found consistently higher densities of unrepaired leaks in the homes of people of color, lower income persons, renters, adults with lower levels of education, and limited English-speaking households. These same groups were more likely to experience slower repair times and significantly older unrepaired leaks.

[143] This calculation is based on a review of gas transmission pipeline incident reports, excluding incidents attributed to other causes such as "mechanical puncture," "rupture" or "other."

pipeline. However, the gas transmission annual report form for CY 2023 requires operators report only the number of leaks repaired—not all detected leaks.[144] In addition, 49 CFR part 192 does not provide guidance for when operators must complete a "prompt" repair of hazardous leaks, much less other leaks. If non-hazardous leaks occur on gas transmission pipelines at just a fraction of the average per-mile rate of hazardous leak repairs noted in annual reports over the last decade, there would be a significant number of additional, unreported leaks on gas transmission pipelines each year. Those unreported leaks would generally not be subject to prescribed repair timelines under PHMSA's previous regulations. Although some of those leaks could be identified and corrected in a timely manner pursuant to PHMSA's IM regulations at subpart O, the limited application of those requirements and the significant discretion given to operators in designing and executing IM plans do not guarantee any such leaks would be identified and remediated promptly.

PHMSA's prior regulations tolerated the persistence of numerous leaks on part 192-regulated gas gathering pipelines. This is illustrated by information on leak repairs from operators' annual reports. In 2023 annual reports, Types A, B, and C regulated onshore gas gathering operators reported 866 leak repairs on 106,130 miles of regulated onshore gathering lines, or approximately the repair of 8.2 leaks per 1,000 miles, which is a rate more than twice reported for gas transmission pipelines at 3.6 leak repairs per 1,000 miles. Even when limited to higher-pressure Type A and Type C regulated gathering lines, the reported leak rate is 6.6 leaks

[144] PHMSA Form F 7100 2-1 CY 2022 and 2023 and instructions. Available at https://www.phmsa.dot.gov/forms/gas-transmission-and-gathering-annual-report-form-f-71002-1.

per 1000 miles, which is 82 percent higher than the leak rate on gas transmission lines. These results are shown in the table below:

Facility Type	**Miles**	**Leak Repairs**	**Leak repairs per 1000 miles**
Gas Transmission	296,684	1,066	3.6
Type A Gathering	8,583	46	5.4
Type B Gathering	4,620	201	43.5
Type C Gathering	92,927	619	6.7
Type A and C	101,509	665	6.6
Regulated Onshore Gathering Total	106,130	866	8.2

Similar to the data on gas distribution and transmission lines, the annual report-derived data for gathering lines understates the total number of leaks on regulated onshore gathering lines, and the total number of leaks on gathering lines not previously subject to any meaningful Federal repair requirements is likely even higher than reported leak repairs. The gap between the number of actual leaks and reported leak repairs in CY 2023 is likely especially high for Type C gathering lines because most Type C gathering lines were exempt from the leak survey and repair requirements at § 192.9(f), and Type C gathering lines with an outside diameter less than or equal to 12.75 inches were not required to begin leak survey and repair requirements until 2024.[145]

[145] Type C gathering lines with an outside diameter less than or equal to 12.75" in diameter were subject to a notice of enforcement discretion until May 17, 2024. https://www.phmsa.dot.gov/regulatory-compliance/phmsa-guidance/notice-limited-enforcement-discretion-type-c-gas-gathering.

The number and persistence of leaks on gas distribution, transmission, and gathering pipelines previously tolerated by PHMSA regulations presented considerable risks to public safety.[146] Leaks that were or became reportable incidents pursuant to 49 CFR part 191 were consequential to public safety in that operators are required to report incidents when they cause at least one death, a personal injury necessitating in-patient hospitalization, property damage of $122,000 or more (excluding the value of the gas itself), or 3 MMCF or more gas lost. Similarly, each of the hazardous leaks observed on gas pipelines under prior PHMSA regulations are a hazard with respect to public safety. Since leaks in pressurized systems can degrade over time into catastrophic failures, even those leaks that have not yet been reported as incidents or otherwise designated as hazardous in that they do not involve an existing or imminent risk of ignition can nevertheless give rise to such risk if an operator does not repair them.

Even with adequate leak detection equipment, recent incidents demonstrate that an operator can fail to locate or adequately respond to dangerous leaks if their leak survey and investigation procedures are inadequate. As described in section II.D.4 of the NPRM, this is most clearly illustrated by a series of incidents that occurred on a gas distribution pipeline operated by Atmos Energy in Dallas, TX, that occurred in February 2023. While the operator used effective leak detection equipment during the investigation of the first two releases, the tools were ineffective in the rain and wind conditions prevailing during the investigations and the operator

[146] PHMSA discusses in this section only direct public safety consequences of leaks; however (as explained in section II.D.3), leaks and other releases from gas pipelines can also have second-order public safety impacts resulting from climate change-induced natural force damage and equipment malfunction.

failed to detect leakage from a cracked main, which later resulted in a fatal explosion.[147] This incident also demonstrated the impact of wet weather conditions and other changes to the leak environment can affect gas migration and the potential value of residential methane detectors for reducing the consequences of gas pipeline incidents.

Lastly, any leak from a gas gathering pipeline can present unique public safety risks. Natural gas gathering pipelines are often located in the vicinity of socially vulnerable populations.[148] Additionally, unprocessed natural gas transported by gathering pipelines typically contains significant quantities of VOCs and HAPs, several of which are known carcinogens and, as discussed in further detail in the RIA for this rulemaking and earlier in this document, can result in long-term adverse health effects to exposed populations. Further, corrosives entrained in the unprocessed natural gas can accelerate corrosion in the vicinity of leaks, thereby increasing the risk of a catastrophic failure.

As discussed in section II.B, current methane emissions data identifies leaks across U.S. natural gas distribution, transmission, and gathering line pipe as a significant contributor to U.S. methane emissions, with the GHGI estimating nearly 289.2 kt CH_4 in 2022. But, as discussed earlier, current methane emissions estimates could significantly understate actual methane emissions. GHGRP reporting requirements do not capture all gas pipeline mileage subject to PHMSA's regulations at 49 CFR parts 191 and 192, introducing uncertainty into whether the

[147] NTSB, Pipeline Accident Report 21/01 "Pipeline Accident Report: Atmos Energy Corporation Natural Gas-Fueled Explosion: Dallas, Texas: February 23, 2018" (Jan. 12, 2021).

[148] Emanuel et al., "Natural Gas Gathering and Transmission Pipelines and Social Vulnerability in the United States," 5 GeoHealth (June 2021) (concluding that natural gas gathering and transmission infrastructure is disproportionately sited in socially-vulnerable communities).

national average methane emissions estimates derived from such reports may be accurately extrapolated to all PHMSA-regulated gas pipelines. Additionally, recent evidence from aerial surveys of a small, 7,500 square kilometer swath of the Permian basin[149] found leaks from natural gas gathering pipelines to be a larger source of methane emissions than would be calculated using the national average in the GHGI.[150] A series of 2-week aerial surveys conducted for the Environmental Defense Fund's (EDF) Permian Methane Analysis Project in the fall of 2019, summer of 2021, and fall of 2021 observed between 50 and 350 leaks attributed to gas gathering line pipe, of which roughly half are likely attributable to part 192-regulated gathering line pipe. PHMSA determined this by comparing the leak coordinates for gathering line pipe from the raw data of the EDF's Permian Methane Analysis Project[151] to geospatial data for specific gathering pipelines downloaded from the Texas Railroad Commission (TRRC) website.[152] PHMSA then reviewed the TRRC's database of attributes of those gathering pipelines to determine pipeline diameter, using that metric to determine whether an observed leak was on a part 192-regulated gathering pipeline. The leaks identified in these aerial surveys, moreover, were not minimal: the average leak rate observed by EDF was 273 kg CH_4 per hour, correlating to roughly a metric ton of methane emitted to the atmosphere every 5 days. Even this

[149] The entire Permian basin covers approximately 86,000 square miles—more than 220,000 square kilometers.

[150] See Yu et al., "Methane Emissions from Natural Gas Gathering Pipelines in the Permian Basin," Environ. Sci. Technol. Lett. (Nov. 8, 2022) (Yu Study) ("The EF [(emissions factor)] derived from each of the four aerial surveys is more than an order of magnitude higher than the EPA's published values [for national average emissions]."). The emissions factors calculated from this study were also "4-13 times higher than the highest estimate derived from a published ground-based survey of gathering lines."

[151] See EDF, Permian Methane Analysis Project, https://permianmap.org/ (last accessed Aug. 30, 2024).

[152] https://rrc.texas.gov/oil-and-gas/publications-and-notices/maps/ (last accessed July 25, 2022).

limited Permian Basin data, if projected nation-wide, could under-report the number and scale of leaks from methane emissions from gas gathering pipelines.[153] Many of the gathering pipelines in the Permian Basin are relatively new, while older gas gathering infrastructure in other production regions may leak at higher rates due to time-dependent threats and legacy design and construction techniques.

4. State Leak Detection, Repair, and Reporting Requirements

State regulatory requirements impose a patchwork of obligations on pipeline operators with respect to LDAR. Pertinent requirements can vary from one State to the next and even within a single State based on the classification of the pipeline in question or the gas being transported. Many of those State requirements, like PHMSA's previous regulations, do not address the potential environmental harms posed by gas pipeline leaks and other releases. And, according to data from the National Association of Pipeline Safety Representatives (NAPSR), a minority of the States have LDAR regulations or leak reporting requirements that exceed the current minimum Federal regulations for any type of gas pipeline.[154]

A handful of States require more frequent leak surveys than historically required by 49 CFR part 192. Many of those State survey requirements apply to only certain types of pipelines, with more demanding requirements for distribution systems than for gas gathering or intrastate

[153] The Yu Study acknowledged that its data may also be underestimating emissions from gathering pipelines. The authors conservatively excluded any emissions sources in areas of co-located gathering and transmission pipelines where the source could not be definitively attributed, although the authors noted that it would be reasonable to assume at least some of those sources were from gathering pipelines. See Yu et al. "Methane Emissions from Natural Gas Gathering Pipelines in the Permian Basin," (Nov. 8, 2022).

[154] Zanter, Mary. "Presentation of NAPSR at 2021 Public Meeting" (May 5, 2021), https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=1150.

transmission lines. However, these additional requirements primarily address public safety rather than environmental harms. Certain States also require operators to conduct more frequent surveys based on the location of the pipeline; for example, if the pipeline delivers gas to high-occupancy buildings; buildings of public assembly such as theaters, hospitals, or schools; or if the pipeline is near bridges or other transportation infrastructure. Other States provide a definition of the term "business district," which is not defined in part 192, and employ more stringent requirements for leak surveys than the provisions in § 192.723. While a small minority of States do require increased surveying of cast-iron pipes under certain conditions, few States require operators to replace or remediate these or other types of leak-prone pipe materials.

A minority of States have more specific requirements for operators to use leak detection equipment than provided in PHMSA regulations. NAPSR's Compendium[155] identified three States and the District of Columbia having leak detection equipment requirements that are more demanding than PHMSA's requirements. Those States' requirements appear to focus on methane leaks from natural gas pipelines rather than leaks from pipeline facilities transporting other gases. A handful of States specify allowable leak detection equipment, generally requiring operators use a flame ionization detector (FID) or equivalent device when performing leak surveys. For example, Maryland and Arkansas regulations require operators to use FID, combustible gas indicators in a barhole,[156] optical methane detectors, or other methods approved by the Maryland

[155] NAPSR. "Compendium of State Pipeline Safety Requirements & Initiatives Providing Increased Public Safety Levels compared to the Code of Federal Regulations." 3rd Edition. February 2022. https://www.napsr.org/compendium.html.

[156] A barhole is a small hole dug into the ground in order to measure the concentration of gas within the soil by taking a sample within the barhole with a probe.

Public Service Commission. New Jersey adopted an energy-related master plan in their overall State-wide climate goals that specifically directs the State utility commission to establish a standard for operators to use ALD technologies when performing leak surveys. NAPSR data indicates, however, that most States do not have any more demanding requirements than PHMSA for the leak detection equipment used by operators. NAPSR's Compendium similarly indicates that few States have right-of-way patrol requirements for gas gathering or transmission pipelines that are more demanding than those in prior PHMSA regulations.

Apart from leak detection requirements, NAPSR's Compendium yields that most States have neither adopted the GPTC Guide's leak grading and repair criteria nor have regulatory requirements supplementing the requirements for leak grading or leak repair in 49 CFR part 192. A few States, including Texas, Kentucky, Massachusetts, and New York, have adopted leak grading and repair standards like those in the GPTC Guide. But many more States reported to NAPSR that they automatically adopt and incorporate PHMSA's regulations for leak grading and repair into their regulations and do not otherwise introduce more stringent requirements. Some of those States noted that they assume some operators follow the GPTC Guide guidance for the grading and repair of leaks described in section II.D.8 of that document. Few States have specific requirements for replacing gas pipelines known to leak based on material, design, or past O&M history; among those States, replacement initiatives generally focus on gas distribution pipelines rather than gas gathering or transmission pipelines.

Of that minority of States that have regulations exceeding the historic requirements in 49 CFR part 192 for grading and repairing leaks, most indicated that they followed a grading system resembling the GPTC grading system, where they classify leaks as grade 1, grade 2, or grade 3 based on relative safety hazards. However, these States have not imposed leak grading and repair requirements uniformly across each classification of pipeline. PHMSA found that mandatory repair timelines also differed among those States—particularly with respect to grade 2 and grade 3 leaks.

Some States do not have specific requirements for monitoring and repairing grade 2 leaks and defer to operator procedures. Other States noted they require operators to recheck grade 2 leaks on subsequent surveys, per an operator's procedures. Some States have requirements for operators to reassess grade 2 leaks every 6 months, with a few States requiring additional or monthly surveys until the leaks are cleared. There is also a wide variety of State approaches to the repair timelines for grade 2 leaks: States largely require operators to repair grade 2 leaks anywhere from 12 months to 24 months after the date of discovery, with a handful of States requiring more immediate repairs.

Monitoring requirements for grade 3 leaks also vary widely between those States with grade 3 leak grading and repair requirements, with some States requiring operators to monitor grade 3 leaks every 6 months, and other States requiring operators to monitor grade 3 leaks every 15 months. The States that have requirements for repairing grade 3 leaks follow one of two paths: either the State requires that operators repair grade 3 leaks within a prescriptive timeframe, such as 24, 30, or 36 months after discovery, or the State requires operators to have a maximum number of outstanding grade 3 leaks. Some States only require operators to repair grade 3 leaks if the leaks have a relatively high emission rate. The methods for identifying high-emitting grade 3 leaks vary by State. For example, Massachusetts defines an "environmentally significant" grade 3 leak as one with a "leak extent" (the land area affected by gas migration) of 2,000 square feet or greater, or one with the highest barhole reading of 50 percent or more gas in air, and requires the operator repair it within either 2 years or 12 months, depending on the extent of gas migration.

5. The Limits of PHMSA Regulation and State and Operator Initiatives in Reducing Intentional Methane Releases from Gas Pipeline Facilities

In section 114 of the PIPES Act of 2020, Congress introduced requirements for operators of gas pipeline facilities to update their inspection and maintenance procedures to minimize all releases of natural gas from their facilities—including intentional, vented emissions—in recognition of the significant environmental harm from those emissions. As described in section II.B, equipment venting, blowdowns, and other vented emissions of methane account for a large portion of the total methane emissions from U.S. natural gas pipeline facilities—particularly natural gas transmission pipelines. However, despite the significant environmental impact of those emissions, PHMSA and State pipeline safety regulations have largely avoided explicit restrictions on vented emissions. Moreover, the absence of robust reporting requirements for those emissions under 49 CFR part 191 have historically inhibited PHMSA's ability to identify systemic issues.

49 CFR part 191 previously did not require operators to report intentional releases of methane or other gases, regardless of the total volume of gas emitted, unless the release caused death, hospitalization, or significant property damage. Similarly, regulations in parts 192 and 193

did not require an operator to minimize intentional releases unless they presented a public safety hazard.[157] These regulatory gaps could permit situations, such as operators configuring pressure relief devices to establish overly-conservative setpoints, resulting in avoidable emissions being released because those pressure relief devices vent methane more frequently than necessary to maintain system pressure within safe operating bands. Incident reports and National Response Center (NRC) reports submitted to PHMSA for pressure relief device malfunctions provide a sense of the magnitude of potential emissions from improperly configured pressure relief devices: each incident can result in the release of millions of cubic feet of methane.

Similar to the voluntary efforts industry has made towards LDAR efforts, the voluntary industry efforts to reduce emissions from blowdowns fall short in minimizing vented emissions. However, many voluntary operator efforts either parallel or directly invoke best practices previously recommended by the EPA's voluntary methane reduction programs. An operator could commit to cutting pipeline blowdown emissions by at least 50 percent by any of the following methods:[158]

- Routing gas to a compressor or capture system for beneficial use;
- Routing gas to a flare;

[157] See, e.g., §§ 192.169 and 192.617(a)(2) (requiring discharge piping for compressor station pressure relief devices and emergency shutdown systems vent to locations that would avoid public safety hazards) and 192.199(e) (requiring pressure relief and limiting devices have discharge stacks, vents, or outlet ports be located where gas can be discharged into the atmosphere without undue hazard).

[158] EPA, "Natural Gas STAR Methane Challenge Program BMP Commitment Option Technical Document" at 21 (August 2024).

- Routing gas to a low-pressure system by taking advantage of existing piping connections between high- and low-pressure systems, temporarily resetting or bypassing pressure regulators to reduce system pressure prior to maintenance, or installing temporary connections between high- and low-pressure systems; or
- Utilizing hot tapping, a procedure that makes a new pipeline connection while the pipeline remains in service, flowing natural gas under pressure, to avoid the need to blowdown gas.

Operators do not universally participate in the voluntary industry emissions reduction efforts noted above, but those efforts hint at the potential for significant reductions in vented emissions if applied across all gas pipeline facility operators. In 2022 alone, a mere 8 participants in the EPA's Methane Challenge transmission pipeline blowdown mitigation program, operating 45 gas transmission pipeline facilities, reduced emissions by 4 million metric tons of CO_2 equivalent estimated by calculation or measurement in accordance with 40 CFR part 98, subpart W, or, for non-subpart W facilities, an alternative method.[159] These operators accomplished through voluntary actions, including reducing emissions from over 640 planned pipeline blowdowns and the repair or replacement of leaking equipment components.

D. GPTC Guide

In general, the leak grading and repair requirements in this final rule build on the framework described in the GPTC Guide but with modifications to help ensure public safety,

[159] EPA, "Methane Challenge Program Accomplishments," https://www.epa.gov/natural-gas-star-program/methane-challenge-program-accomplishments (last accessed Aug. 28, 2024).

improve enforceability, and establish criteria for operators to prioritize the repair of leaks that pose a hazard to the environment. Some operators incorporate the GPTC Guide leak identification, grading, and mitigation criteria within their inspection and maintenance procedures using the "LEAKS" mnemonic as an aide to their personnel tasked with managing leak detection and remediation.[160] The non-mandatory Appendix M to ASME B31.8, "Gas Transmission and Distribution Piping Systems," contains leak grading and repair criteria similar to the contents of the GPTC Guide.[161] However, that standard—like the GPTC Guide—specifies neither technology nor performance requirements for operator leak detection programs, and it contains no repair schedule for grade 3 leaks. Not all operators incorporate the GPTC Guide or similar standards from American Society of Mechanical Engineers (ASME) B31.8 within their inspection and maintenance procedures, but in general, the framework is widely recognized throughout the industry.

The GPTC is an ANSI-accredited committee (ANSI Z380, or the GPTC Committee) that was formed in the late 1960s under the ASME. The GPTC Committee operates under a consensus process and is independent. The GPTC Committee is composed of approximately 100 members from all facets of the gas industry, including gas distribution, transmission, storage, and gathering operators and manufacturers of gas-related equipment. The GPTC Committee also has

[160] The "LEAKS" management system mnemonic consists of Locating the leak, Evaluating its severity, Acting appropriately to mitigate the leak, Keeping records, and Self-assessing to determine if additional actions are necessary to keep the pipeline system safe.

[161] ASME, B31.8-2007, Gas Transmission and Distribution Piping Systems, 2007 Edition (2008) (ASME B31.8-2007). PHMSA regulations incorporate by reference elements of ASME B31.8-2007 in connection with yield strength testing procedure (§ 192.619(a)(1)(i)) or the alternative MAOP requirements (§ 192.620)—but not non-mandatory appendix M.

members from the regulatory community, including PHMSA, the National Transportation Safety Board (NTSB), and other Federal and State regulatory agencies. Approximately 40 of the GPTC Committee's members, including PHMSA, are voting members.

The GPTC Committee publishes the GPTC Guide as an implementation tool intended to facilitate gas pipeline operator compliance with PHMSA regulatory requirements.[162] The first edition of the GPTC Guide was published in 1970, around the same time the PSR were first promulgated. The GPTC Guide is under continuous review and may be updated when prompted by pending rulemakings, NTSB reports, and requests from stakeholders, including PHMSA, NAPSR, or members of the public. The GPTC Committee periodically reviews requests for updates and may create a task group, if necessary, to issue new or amended guidance of versions of the GPTC Guide. The current edition of the GPTC Guide is the 2022 edition (including Addendum 1), published in June 2022.

Like the prior PSR, the GPTC Guide's leak grading and repair criteria are focused primarily on public safety rather than environmental protection. While the GPTC Guide itself has not been incorporated by reference in the PSR, several States have adopted at least the tiered leak grading criteria of the GPTC Guide and associated repair requirements into their regulations governing gas pipelines,[163] and PHMSA has referenced it occasionally in its implementing

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[162] GPTC Guide at page 17 ("While the GPTC Guide is intended principally to guide operators of natural gas pipelines, it is a valuable reference for operators of other pipelines covered by Part 192").

[163] See National Association of Pipeline Safety Representatives (NAPSR), Compendium of State Pipeline Safety Requirements and Initiatives Providing Increased Public Safety Levels Compared to Code of Federal Regulations, Third Edition (Feb. 2022) (Compendium). References to "NAPSR" or to pertinent State requirements in this final rule will, unless otherwise noted, will be to information within the Compendium.

guidance.[164] Additionally, some gas pipeline operators incorporate sections of the GPTC Guide into their O&M procedural manuals for detecting, investigating, and classifying leaks.

The GPTC Guide contains appendices that provide procedures to assist operators in complying with 49 CFR part 192. The GPTC Guide also provides guidance for controlling methane leaks from natural gas pipelines in Appendix G-192-11. For gas distribution pipelines, section 6.2 of the DIMP guidance in Appendix G-192-8 describes possible elements of an "effective leak management program" and references the criteria for grading leaks from Appendix G-192-11 and, for liquefied petroleum gas (LPG) systems, Appendix G-192-11A. Each of those sections includes tables 3a, 3b, and 3c summarizing the grading criteria and recommended repair requirements. The grading criteria from GPTC Guide Appendix G-192-11 and Appendix G-192-11A are discussed below (hereafter, references to the GPTC Guide refer specifically to Appendix G-192-11 and 11A, unless otherwise specified).

Section 5.5 of the GPTC Guide characterizes a grade 1 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." This mirrors the definition of a "hazardous leak" at 49 CFR 192.1001. This characterization does not consider potential harms to the

[164] *See, e.g.,* PHMSA, "Distribution Integrity Management: Guidance for Master Meter and Small Liquefied Petroleum Gas Pipeline Operators" (2013) at 2 (directing larger distribution pipeline operators to refer to GPTC guidelines); PHMSA, Interpretation Response Letter No. PI-93-009 (Feb. 11, 1993) (recommending public stakeholder consult the GPTC Guide for further determination of instruments and techniques to be used in certain leak detection activities); *see also* PHMSA, Interpretation Response Letter No. PI-99-0105 (Dec. 1, 1999) (stating that the GPTC Guide "is a document endorsed by us which contains information and some methods to assist the gas pipeline operator in complying with the regulations contained in 49 CFR part 192").

environment, and the phrase "existing or probable hazard" is not defined in any part of the GPTC Guide. However, Table 3a of the GPTC Guide provides the following examples of grade 1 leaks:

1) Any leak that, in the judgment of operating personnel at the scene, constitutes an immediate hazard;

2) Escaping gas that is ignited;

3) Any indication of gas which has migrated into or under a building, or into a tunnel;

4) Any indication of gas which has migrated to at an outside wall of a building or where gas would likely migrate into a tunnel;

5) Any reading of 80 percent [of the lower explosive limit] LEL, or greater, in a confined space;[165]

6) Any reading of 80 percent LEL, or greater, in small substructures (other than gas-associated substructures) from which gas would likely migrate to the outside wall of a building; and,

7) Any leak that can be seen, heard, or felt, and which is in a location that may endanger the general public or property.

Building on the prior 49 CFR 192.703(c) requirement that hazardous leaks (i.e., grade 1 leaks) be repaired promptly, the GPTC Guide further specifies that an operator must take immediate and continuous action to protect life and property until the conditions are no longer hazardous. Per the GPTC Guide, such continuous actions could include implementing an

[165] The Lower Explosive Limit (LEL) is the lowest concentration of gas that will burn in air in the presence of an ignition source.

emergency plan written in accordance with § 192.615; evacuating the premises; blocking off an area; re-routing traffic; eliminating ignition sources; and venting the area by removing manhole covers, bar-holing, or installing vent holes. The GPTC Guide also notes that, for grade 1 leaks, operators should stop the flow of gas by closing valves or by other means and notify appropriate police and fire departments.

A grade 2 leak is an intermediate risk classification in the GPTC Guide. The GPTC Guide characterizes a grade 2 leak as a "leak that is non-hazardous at the time of detection but that requires or justifies a scheduled repair based on probable future hazard." Like the description of a grade 1 leak, the characterization of a grade 2 leak in the GPTC Guide does not address risks to the environment and does not provide a definition for the term "probable future hazard," although example criteria are provided in Table 3b of the GPTC Guide. For grade 2 leaks, these criteria include leaks that require action ahead of the ground freezing or where changes in venting conditions would likely cause gas to migrate to the outside wall of a building. Grade 2 leaks could also include leaks with a reading of 40 percent of the LEL or greater under a sidewalk in a wall-to-wall paved area that does not qualify as a grade 1 leak; a reading of 100 percent LEL or greater anywhere under a street in a wall-to-wall paved area that has significant gas migration and does not qualify as a grade 1 leak; a reading between 20 percent and 80 percent of the LEL in a confined space or in a small substructure; any non-zero concentration reading on a pipeline operating at 30 percent of SMYS or greater in a Class 3 or Class 4 location that does not qualify as a grade 1 leak; and finally, any leak that, in the judgment of the operating personnel at the scene, is of sufficient magnitude to justify or require a scheduled repair. These examples demonstrate that the grade 2 leak classification, like the grade 1 classification, focuses operators on hazards to persons and property without consideration of impacts on the environment.

The GPTC Guide requires that, upon detecting a grade 2 leak, an operator should repair or clear the leak "within one calendar year but no later than 15 months from the date the leak was reported." The GPTC Guide states that, in determining the repair priority for the leak, an operator should consider the extent of gas migration, the proximity of gas to buildings and sub-surface structures, and the soil type and conditions, including frost cap, moisture, or natural venting. Operators can take a range of actions in addressing grade 2 leaks under the GPTC Guide. Some grade 2 leaks that are evaluated by the criteria listed above may justify a scheduled repair within 5 working days, whereas others might justify repair within 30 days. The GPTC Guide suggests that operators should schedule some grade 2 leaks for repair on a "normal routine basis," with periodic re-inspection as necessary. The GPTC Guide also suggests that operators should reevaluate grade 2 leaks at least once every 6 months until they are cleared, establishing a frequency of reevaluation based on the location and magnitude of the leak.

The GPTC Guide characterizes a grade 3 leak as "a leak that is non-hazardous at the time of detection and can reasonably be expected to remain non-hazardous." The term "non-hazardous" is not itself defined, but comparison to the grade 1 and grade 2 descriptions indicates that the grade 3 classification is intended to be a catch-all classification for all leaks that do not constitute either grade 1 or grade 2 leaks, including those leaks that are hazardous to the environment without representing a potential risk to public safety. Based on the criteria in Table

3c, grade 3 leaks would include leaks where there is a reading of less than 80 percent LEL in a small gas-associated substructure, any reading under a street in areas without wall-to-wall paving where it is unlikely that gas could migrate to the outside wall of a building, and any reading of less than 20 percent LEL in a confined space. The GPTC Guide suggests that operators should reevaluate grade 3 leaks during their next scheduled survey or within 15 months of the date the leak is reported, whichever comes first, and continue reevaluations until the leak is either regraded or is no longer leaking. The GPTC Guide does not require the repair of grade 3 leaks. In comments submitted following the 2021 Public Meeting, the AGA and others noted the limitations of the GPTC Guide leak grading system with respect to environmental safety considering the GPTC Guide's focus on the repair and remediation of leaks that are hazardous to public safety only.

The GPTC Guide allows operators to regrade existing leaks based on changes operators identify during subsequent evaluations. If an operator discovers, during a reevaluation, that a grade 2 or grade 3 leak has become worse following its initial detection and grading to the point where the leak would be classified at a higher grade, the operator must upgrade the leak to its appropriate grade and take appropriate action in accordance with the new grade. The GPTC Guide also permits operators to downgrade leaks by making temporary repairs to make the leak less hazardous. For example, an operator may vent a grade 1 leak by drilling multiple barholes into the soil in the immediate vicinity of the leak or by leaving vault boxes open to the atmosphere before grading the leak. These techniques can help ensure that a leak is not an immediate hazard to persons or property and justify downgrading a grade 1 leak to a grade 2 leak.

As described in section II.C.1, PHMSA's previous regulations required operators to only repair "hazardous leaks." In practice, the term "hazardous leak" has corresponded to a grade 1 leak under the three-grade leak classification framework in the GPTC Guide; a grade 1 leak is the most urgent classification under this framework. Section 5.5 of appendix G-192-11 of the GPTC Guide characterizes a grade 1 leak as one 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." However, PHMSA regulations did not previously require the repair of non-hazardous leaks that would be classified as grade 2 or grade 3 based on the GPTC Guide. Regarding the replacement or remediation of pipelines known to leak, appendix G-192-18 of the GPTC Guide suggests operators consider replacement of cast-iron pipe based on the maintenance and leak history and operational and environmental circumstances, and the GPTC guide provides operators guidance on factors and situations they should consider.

E. EPA Emissions Monitoring and Reporting Rules

On March 8, 2024, the EPA published a final rule titled "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" (2024 New Source Performance Standard and Emissions Guidelines final rule) which adopts emissions control standards for VOCs and GHGs (methane) from the crude oil and natural gas source category.[166] These requirements include LDAR[167] standards and standards related to the design, maintenance, and operation of compressors, pneumatic pumps, pneumatic controllers, wells, and various other components in the oil and natural gas industry. PHMSA jurisdictional facilities potentially also subject to EPA's standards include gas transmission, gas gathering, LNG, and UNGSF pipeline facilities. Distribution systems are not a covered source under EPA's rules at 40 CFR 60 subparts OOOO through OOOOc; however, pipelines defined as distribution lines in § 192.3 that are a part of a transmission or gathering system could be covered under 40 CFR 60 requirements as the definitions do not precisely align. Subpart OOOOa covers sources where construction, modification, or reconstructed commenced after September 18, 2015, and on or before December 6, 2022. Subpart OOOOb covers facilities where construction, modification, or reconstructed commenced after December 6, 2022 (new, modified, and reconstructed sources), and the Emissions Guidelines in subpart OOOOc apply to states to follow in developing, submitting, and implementing state plans to establish performance standards to limit GHG emissions from existing sources in the Crude Oil and Natural Gas source category (i.e., existing sources constructed prior to December 6, 2022).

Most relevant for today's final rule, the 2024 New Source Performance Standard and Emissions Guidelines final rule includes methane emissions monitoring and repair requirements

[166] *See* 89 Fed. Reg. 16820 (Mar. 8, 2024). Aspects of EPA's rules for these sources are discussed in several parts of this document. Please refer to EPA's regulations under 40 CFR 60 subparts OOOO through OOOOc for a full description of those requirements.

[167] EPA specifically regulates fugitive emissions at well sites, centralized production facilities, and compressor stations in addition to equipment leaks at natural gas processing plants.

(in the form of presumptive standards for the Emission Guidelines for existing sources) for compressor stations (and other fugitive emissions component affected facilities). Methane emissions monitoring requirements are analogous to PHMSA requirements for patrols, leak surveys, and repairs adopted in this final rule. For new, modified, and reconstructed sources covered under OOOOb, default requirements for fugitive emissions monitoring are defined in CFR 60.5397b, and alternative emissions monitoring standards, including the use of screening surveys, are defined in 40 CFR 60.5398b. Under the default emissions monitoring requirements in 40 CFR 60.5397b for fugitive emissions components affected facilities located at compressor stations, operators must perform an initial monitoring survey followed by periodic monitoring surveys with "audio, visual, and olfactory" (AVO) or any other detection method. An AVO monitoring survey is a sensory survey analogous to a patrol in part 192. Additionally, an operator must perform an initial monitoring survey of a compressor affected facility followed by a monitoring survey at least quarterly using OGI or EPA Method 21 in appendix A-7 to part 60 (comprehensive survey using handheld leak detector equipment, such as an FID), with an interval between surveys of no less than 60 calendar days. In this context, a fugitive emission is any indication of emissions observed from a fugitive emissions component using AVO, any emission visible with OGI or that produces an EPA Method 21 instrument reading of 500 ppm or more (measured by placing the instrument probe inlet at the surface of the component interface where leakage could occur).[168]

[168] EPA Method 21, Appendix A to 40 CFR 60. Section 8.3.1

Under the default emissions monitoring standards for compressor stations, alternative monitoring frequencies apply in certain circumstances. For facilities located on the Alaska North Slope, 40 CFR 60.5397b(g)(1)(vi) requires an OGI or EPA Method 21 survey at least annually rather than the monthly AVO and quarterly instrumented survey for other facilities. Additionally, for EPA Method 21 surveys, components that are designated difficult-to-monitor (components that cannot be monitored without elevating monitoring personnel more than 2 meters above the surface, see 40 CFR 60.5397b(g)(2)) or unsafe-to-monitor (components that cannot be monitored because monitoring personnel would be exposed to immediate danger, see 40 CFR 60.5397b(g)(3)) may be identified and put on an alternative monitoring schedule in a written plan; however "difficult to monitor" components must be monitored at least once each calendar year.

The alternative emissions monitoring requirements in 40 CFR 60.5398b permit use of alternative monitoring methods that have been approved by EPA, at prescribed frequencies, with notification to the EPA. Most notably, this section prescribes requirements for complying with methane monitoring requirements through the use of periodic screening surveys under 40 CFR 60.5398b(b) based on a flow-rate standard or continuous monitoring under 40 CFR 60.5398b(c). For periodic screening surveys, the minimum detection limit is prescribed at table 1 to subpart OOOOb of 40 CFR part 60 and is defined in kilograms per hour (kg/hr) of methane with a 90 percent probability of detection. The minimum detection threshold for screening surveys varies from 1 kg/hr to 15 kg/hr and is based on a function of screening survey frequency, where less sensitive screening surveys must be performed more frequently. For continuous monitoring under 40 CFR 60.5398b(c), monitoring equipment must be capable of detecting at least 0.4 kg/hr of methane at least once every 12-hour block, and the action levels for compressor stations are a 90-day rolling average of 1.6 kg/hr of methane over baseline emissions or a 7-day rolling average of 21 kg/hr over baseline emissions.

For compressor stations, 40 CFR 60.5397b(h) requires operators using OGI or EPA Method 21 to attempt to repair the cause of fugitive emissions found during a monitoring survey within 30 days of detection and complete the repair as soon as practicable, but no later than 30 days after the first repair attempt. However, an operator can delay a repair to be completed during the next scheduled station shutdown, or within 2 years of detecting the fugitive emissions, whichever is earliest, for repairs that: are technically infeasible; would require a blowdown, a compressor station shutdown, a well shutdown, or a well, shut-in; or that would be unsafe to repair during the course of operation (*see* 40 CFR 60.5397b(h)(3)(i)). Additionally, if the repair requires replacement of a fugitive emissions component or a part thereof, but the replacement cannot be acquired and installed within the specified repair timelines, 40 CFR 60.5397b(h)(3)(ii) requires an operator to order replacement parts no later than 10 calendar days after the first attempt at repair, with the operator completing the repair as soon as practicable but no later than 30 calendar days after receipt of components, unless the alternative timeline discussed above applies. Following repair, identified sources of fugitive emissions must be resurveyed using EPA Method 21 or OGI to help ensure there are no fugitive emissions. 40 CFR 60.5397b(h)(4) specifies that the repair is considered complete when there are no visible emissions found via OGI, an EPA Method 21 instrument indicates a methane concentration less than 500 ppm above background methane, or when no soap bubbles are observed during a soap test, if applicable. For fugitive emissions identified using AVO methods, a repair may be considered complete when there are no indications of fugitive emissions using such methods.

Fugitive emissions monitoring requirements in OOOOa, as amended, and the presumptive standards in the Emissions Guidelines in OOOOc are similar to those for new sources in OOOOb described above. In subpart OOOOa, the 2024 New Source Performance Standards and Emissions Guidelines final rule revises the emissions monitoring requirements in 40 CFR 60.5397a and 60.5398a to clarify that those requirements applied to methane emissions in addition to VOC and to incorporate the delay of repair and alternative monitoring method options that were included in the corresponding OOOOb requirements described above. Similarly, the Emissions Guidelines at 40 CFR 60 subpart OOOOc includes recommended fugitive emissions monitoring requirements in 40 CFR 60.5397c and 60.5398c, which states could use to develop their plans, that are substantially similar to those adopted for new sources in 40 CFR 60 subpart OOOOb as described above.

EPA's March 2024 final rule also includes a Super Emitter Program which requires operators to investigate and respond to EPA-issued notifications of reports of releases of 100 kg/hr of methane or more that is detected by an EPA-approved remote detection method (40 CFR 60.5371, 60.5371a, 60.5371b, 60.5371c).

EPA has also finalized proposed changes to emissions reporting requirements under the GHGRP in 40 CFR part 98 subpart W in a final rule titled "Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determination for Petroleum and Natural Gas Systems" published on May 14, 2024 (Subpart W final rule).[169] These amendments affect certain gas pipeline operators subject to GHGRP, and includes gas distribution, gas transmission, gas gathering and boosting, UNGSF, and LNG facilities that emit 25,000 metric tons of CO_2 equivalent or more per year, refer to existing 40 CFR 98.230 and 98.231 for more information on the scope of GHGRP for natural gas pipeline systems under subpart W. Among the final amendments relevant to this final rule, the Subpart W final rule requires operators of gas pipelines subject to the scope of GHGRP requirements to report "other large release events," for reporting releases that are not appropriately covered under other source categories. Other large release events are defined in 40 CFR 98.238 as any planned or unplanned uncontrolled release to the atmosphere of gas, liquids, or mixture thereof, from wells and/or other equipment that result in emissions for which there are no methodologies in § 98.233 other than under § 98.233(y) to appropriately estimate these emissions. Emissions from blowdowns calculated according to 98.233(i) are not reported under other large release events. According to 40 CFR 98.233(y)(1), emissions are required to reported under the other large release event source category for a release that emits methane at any point in time at a rate of 100 kg/h if the source is not subject to reporting under certain source categories (98.233 (a) through (s), (w), (x), (dd), or (ee)) and for sources subject to reporting under certain source categories (98.233(a) through (h), (j) through (s), (w), (x), (dd), or (ee)), a release that emits methane at any point in time at a rate of 100 kg/hr in excess of the emissions calculated using the applicable source category.[170] The final rule did not adopt the

[169] 89 FR 42062 (May 14, 2024).
[170] 89 FR 42062 at p. 42282. (May 14, 2024).

proposed requirement to also define as an "other large release event" releases with a total volume of 250 mt CO2e (approximately 500 MCF) in addition to the 100 kg/hr criterion. Additionally, the subpart W final rule allows operators more flexibility to use direct measurement methods, rather than prescribed emissions factors, to calculate and report emissions for equipment leaks and other sources.

F. Administrative History

1. PHMSA's May 2021 Public Meeting

PHMSA held the 2021 Public Meeting on May 5 to 6, 2021, to provide stakeholder groups and members of the public an opportunity to share perspectives on improving gas pipeline methane LDAR programs consistent with sections 113 and 114 of the PIPES Act of 2020. The agenda for the meeting included discussions of the sources of methane emissions from gas pipeline systems, the at-the-time current regulatory requirements for fugitive and vented emissions, the at-the-time current industry LDAR practices, and the use of advanced technologies and practices to reduce methane emissions from gas pipeline systems.

Stakeholders were invited to submit written comments in connection with the 2021 Public Meeting. PHMSA received seven comments from individual pipeline operators, leak detection technology service providers, public safety groups, and industry trade organizations, as summarized below. The meeting itself included presentations and panel discussions from representatives from PHMSA, the EPA, NAPSR, the EDF, the Pipeline Safety Trust (PST), the United Association of Plumbers and Pipefitters, the GPTC, the AGA, the American Public Gas Association (APGA), INGAA, the GPA, Pipeline Regulatory Consultants, the Gas Technology

Institute, the Methane Emissions Technology Evaluation Center (METEC) at Colorado State University, QuakeWrap Inc., Bridger Photonics, Safetylics, ProFlex Technologies, ABB Inc., the Federal Energy Regulatory Commission, and the National Association of Regulatory Utility Commissioners. Presentations, recordings, and transcripts from the 2021 Public Meeting are available on PHMSA's public meeting web page.[171]

At the 2021 Public Meeting, the EDF presented a set of recommended elements for an advanced methane leak detection system, including (1) leak detection equipment with a parts-per-billion level of sensitivity[172] and the ability to capture other data for use in an algorithm to understand the size and location of leaks; (2) a defined deployment strategy or work practice to help ensure that accurate data is being collected; and (3) comprehensive data collection on topics such as leak location, estimated leak flow rate or gas emission rate, a coverage map showing which areas were successfully surveyed and which areas were not, and a summary or cumulative loss estimate for the total area surveyed. The AGA observed in their remarks at the 2021 Public Meeting and in their written comments that most currently available leak detection technologies are focused on identifying indications of methane leaks in the air (i.e., gas concentration) rather than measuring the rate of leakage from a component. AGA and others characterized methane concentration as a more appropriate metric for evaluating the public safety risks from explosion than for estimating the amount of methane going to atmosphere.

[171] PHMSA Leak Detection, Leak Repair and Methane Emission Reduction Public Meeting (May 2021). https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=152.

[172] EDF commented that parts-per-billion detection is important in this effort in light of the potential for hidden underground leaks, where only a small volume of gas may migrate through the pavement despite a significant leak buried under the street.

Several stakeholders at the 2021 Public Meeting emphasized the importance of flexibility in PHMSA's consideration of ALD standards, recommending that PHMSA assess the suite of leak detection technologies that are currently commercially available and introduce requirements that promote continued development of advanced technologies. The EDF noted that it was essential that PHMSA set advanced methane leak detection standards that ensure an ongoing process for the continuous improvement of technology, recommending that PHMSA set a floor, not a ceiling, to create a space in Federal standards to push for the development of new ideas and improvements to technology over time for future incorporation. The AGA and others also suggested that applying prescriptive regulations could potentially limit the development of different technologies and innovations, stating that providing operators with flexibility could create opportunities and incentives for developing new technologies and innovations in leak detection and measurement. Similarly, the PST stated that performance-based regulations for ALD and methane reduction should use the capabilities of commercially available ALD technologies as a starting point, but the ALDP standards should change as commercially available technologies develop.

The AGA and others emphasized the value of leak data analysis in lieu of requirements that operators use specific ALD technologies and observed that studies across the gas industry supply chain show that a majority of emissions come from a small number of high-emitting leaks; therefore, leak data analysis enables operators to make substantial inroads on reducing methane emission by identifying and prioritizing repair of the highest-emitting leaks. The AGA and others also urged PHMSA to consider the affordability of any new regulatory requirements and suggested that in some situations, a simpler, less-costly technology or practice may achieve safety and environmental goals more successfully than a newer technology.

2. June 2021 Advisory Bulletin

PHMSA published an advisory bulletin on June 10, 2021, calling operators' attention to the self-executing requirements of section 114 of the PIPES Act of 2020.[173] The bulletin advised operators of pipeline facilities to update their inspection and maintenance plans to eliminate hazardous leaks and minimize gas releases from their pipeline facilities, including intentional venting during normal operations. The bulletin also noted that, per the statutory mandate, operators must revise their plans to replace or remediate pipeline facilities that are known to leak based on their material, design, or past O&M history. The advisory bulletin noted that the PIPES Act of 2020 requires pipeline facility operators to complete these updates by December 27, 2021.

3. February 2022 PHMSA Webinar

On February 17, 2022, PHMSA held an informational public webinar reviewing the requirements for pipeline operator inspection and maintenance plans introduced by section 114 of the PIPES Act of 2020.[174] This webinar was informational, with attendees having the opportunity to submit written comments to the public meeting docket. More than 1,500 individuals registered for the public webinar, including representatives from the gas gathering, transmission, and distribution sectors. During the webinar, PHMSA discussed key elements of

[173] PHMSA, "Pipeline Safety: Statutory Mandate to Update Inspection and Maintenance Plans to Address Eliminating Hazardous Leaks and Minimizing Releases of Natural Gas from Pipeline Facilities," 86 FR 31002 (June 10, 2021) (ADB-2021-01).

[174] PHMSA's presentation during this webinar and a recording of the webinar meeting are available on PHMSA's public meeting web page at https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=159.

the new section 114 requirements and reviewed the applicable timelines for the actions required under section 114. PHMSA also discussed its planned approach for inspecting operator programs and procedures to reduce methane emissions and replace or remediate leak-prone pipes.

4. Notice of Proposed Rulemaking

On May 18, 2023, PHMSA published the NPRM in this rulemaking proceeding, proposing amendments to the gas pipeline safety standards in 49 CFR parts 191, 192, and 193 that were designed to respond to the mandates of the PIPES Act of 2020 and address the risks to public safety and the environment as described above. PHMSA extended the comment period for the NPRM to August 16, 2023, and received approximately 43,000 comments from individuals, operators, industry trade associations, environmental advocacy groups, religious organizations, States, and others. PHMSA continued to receive additional comments after the end of the comment period and following the GPAC meetings.

5. Gas Pipeline Advisory Committee Meetings

Pursuant to 49 U.S.C. 60115, the GPAC met from November 27 through December 1, 2023, and March 25 through March 27, 2024, to assess the technical feasibility, reasonableness, cost-effectiveness, and practicability of the standards proposed in the NPRM. The GPAC voted on recommendations to PHMSA, including changes for PHMSA to implement in this final rule that would make the proposed regulatory amendments more technically feasible, reasonable, cost-effective, and practicable. These recommendations have been documented in the meeting transcripts and committee vote slides[175] and are described in detail in section III below. The transcripts and vote slides together constitute the GPAC report for this rulemaking required under 49 U.S.C. 60115. PHMSA also received some comments from stakeholders in response to the GPAC proceedings, which are available in the docket for the applicable meeting notice. In accordance with 49 CFR 190.323, and to the extent practicable, PHMSA considered such late-filed comments in the development of this final rule.

III. Summary of NPRM Comments, GPAC Recommendations, and PHMSA Responses

The comment period for the NPRM ended on August 16, 2023, after being extended for one month due to requests from the public. PHMSA received approximately 43,000 comments from groups representing the regulated pipeline industry; groups representing public interests, including environmental organizations; State utility commissions and regulators; State Attorneys General; members of Congress; individual pipeline operators; towns and municipalities; and private citizens. PHMSA received several comments after the August 16, 2023, deadline; consistent with 49 CFR 5.13(i)(5) and 190.323, PHMSA considered those late-filed comments due to commenters' interest in the rulemaking and the absence of additional expense or delay resulting from their consideration.

[175] The transcript, briefing material, and vote slides are all available on the webpages for the meetings and in the dockets for this rulemaking. November to December 2023 meeting webpage: primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=167, November to December 2023 docket: PHMSA-2023-0061. The March 2024 meeting webpage is located at primis-meetings.phmsa.dot.gov/meetings/f64a12c1-01fc-444d-9ffa-d0ea90bc314d. The associated docket number for the March 2024 meeting is PHMSA-2024-005.

A significant portion of public comments address the costs and benefits of the proposed requirements in general or specific assumptions and conclusions in the preliminary regulatory impact analysis (PRIA) in particular. PHMSA has summarized and responded to comments regarding the PRIA in Appendix C of the final RIA, which is available in the docket for this final rule.

A. Gas Distribution Leak Surveys—§ 192.723

1. Summary of PHMSA's Proposal

Section 192.723 sets out requirements for leak surveys on gas distribution pipeline systems, including the required survey frequency. Prior to this rulemaking, leak surveys on distribution pipelines in business districts were required at least once each calendar year, with an interval between surveys not to exceed 15 months.[176] Leak surveys were required once every 3 calendar years, with an interval between surveys not to exceed 39 months, on distribution pipelines outside of business districts that are not cathodically protected and where electrical surveys for corrosion are impractical (i.e., bare-steel and cast-iron systems). For all other portions of a distribution system outside of a business district, leak surveys were required once every 5 calendar years, at intervals not exceeding 63 months. Section 192.723 did not distinguish leak survey intervals based on past O&M history; it required operators to use leak detection equipment for leak surveys on gas distribution pipelines but did not contain minimum performance standards for such leak detection equipment nor require any particular technologies

[176] Note: The term "business district" is undefined in part 192. In the NPRM, PHMSA solicited comment on potential criteria for defining the boundaries of a business district for the purposes of this final rule.

that operators must use during those leak surveys. While DIMP includes a general requirement to consider information gained form past design, operations, and maintenance in § 192.1007(b)(2), it does not require operators to consider such factors when determining the frequency of leakage surveys or prescribe any other particular preventative and mitigative measure.

In order to satisfy the mandates from section 113 of the PIPES Act of 2020, including requiring gas distribution operators to conduct LDAR programs that are able 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 health, establishing minimum performance standards that reflect the capabilities of commercially available advanced technologies, and requiring the use of ALD technologies and practices, PHMSA proposed several regulatory amendments in the NPRM that would increase the frequency and effectiveness of leak surveys.

First, PHMSA proposed that leak surveys meeting the minimum performance standards proposed in the NPRM be incorporated within operator ALDPs (*See* sections III.D and III.E), and operators grade and repair any detected leaks in accordance with the framework proposed in the NPRM (discussed in section III.I).

Second, PHMSA proposed to require operators perform more frequent leak surveys to promote the earlier detection and repair of leaks to meet the need for gas pipeline safety by improving the likelihood that leaks are detected before they harm the public and to protect the environment by reducing methane emissions from those leaks. As described above, distribution leak surveys were required either once every calendar year, once every 3 calendar years, or once every 5 calendar years depending on the location, material, and design of the pipeline. The NPRM proposed to generally require leak surveys outside of business districts at least once every 3 calendar years, with an interval between surveys not to exceed 39 months. Leak surveys inside of business districts would still be required annually.

Due to the increased safety and environmental risks of distribution mains and service lines that are either without cathodic protection or are known to leak based on material, design, or past O&M history, PHMSA proposed to require that operators perform a leak survey on such leak-prone pipelines at least once each calendar year, with the interval between surveys not to exceed 15 months, which mirrors the high-priority survey frequency for similarly higher-risk cathodically unprotected pipelines and pipelines inside of business districts. Consistent with section 114 of the PIPES Act of 2020, the NPRM included cast iron, unprotected steel, wrought iron, and historic plastics with known issues as materials "known to leak." In the NPRM, PHMSA invited comment on the value of either explicitly listing, either within part 192 or within periodically issued implementing guidance, historic plastics known to leak or deleting the term "historic" from the proposed regulatory text. Specifically, this request for comment was in the context of the proposed annual survey requirement or for pipeline segment replacement under operators' O&M manuals in accordance with section 114 of the PIPES Act of 2020.

Fourth, PHMSA proposed to require that operators perform a leak survey of a distribution pipeline segment after extreme weather events or land movement that could damage that pipeline segment. PHMSA proposed to require that such a survey be completed within 72 hours of the cessation of the event, with "cessation" defined as the time when the location can be safely accessed by operator personnel, or alternatively, within 72 hours of when the pipeline is returned to service. Such a survey could qualify as a periodic survey and therefore reset the 1- or 3-year clock until the next required periodic survey. PHMSA also proposed to require operators to investigate known leaks when ground freezing or other changes in environmental conditions occur, such as heavy rain or flooding that could affect the venting of gas or could cause gas to migrate to nearby buildings. The proposed investigation would require operators to re-investigate existing leaks for possible gas migration; however, this investigation would not, on its own, qualify as a periodic survey and thus would not reset the 1- or 3-year clock until the next required periodic survey. These types of environmental changes can cause new leaks, reveal previously undiscovered leaks, or exacerbate hazards from known leaks on distribution pipelines, thus meriting additional surveys or investigations. PHMSA invited comment on whether to also require operators perform assessments prior to extreme weather events to prepare for and prevent resulting leaks.[177]

These proposals applied generally to pipeline transportation of any "gas," defined in §§ 191.3 and 192.3 as "natural gas, flammable gas, or gas which is toxic or corrosive," including hydrogen, LPG, and other gases.

The proposed amendments to gas distribution pipeline leak survey requirements are summarized in the table below.

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[177] See, e.g., EPA's NPRM titled "Accidental Release Prevention Requirements: Risk Management Programs Under the Clean Air Act; Safer Communities by Chemical Accident Prevention," 87 FR 53556 (Aug. 31, 2022) (proposing to require, under the Clean Air Act Risk Management Program, that industrial chemical facilities evaluate ways to address natural disasters and consider steps to prevent releases that may result, even before such events occur).

Summary of Distribution Leak Survey Amendments

Facility	Pre-NPRM	NPRM
Outside of Business Districts	5 years not to exceed 63 months	3 years not to exceed 39 months
Pipelines known to leak (cathodically unprotected pipe per former § 192.723).	3 years not to exceed 39 months	Annually, not to exceed 15 months
Inside Business Districts	Annually, not to exceed 15 months	No change
Other Proposed Surveys	-After environmental changes that can affect gas migration. -Following extreme weather events with the likelihood to cause damage to the affected pipeline segment.	

PHMSA also invited comment on the value of more or less frequent leak surveys of plastic pipe systems, the potential means to identify plastic pipe known to leak (e.g., via a surveillance or sampling program) and the alternative considered in the preliminary RIA for operators to survey distribution mains annually; typically, mains are likely to be more accessible to pipeline operators than service lines crossing private property and may therefore be more convenient to survey.

2. Summary of Public Comments

Surveying Frequency Outside Business Districts (§ 192.723(c))

The City of Buford, the GPTC, Watertown Municipal Utilities, the City of Cartersville Gas System, Dominion Energy North Carolina, Dominion Energy Utah, Wyoming, Idaho, Dominion Energy Ohio, Dominion Energy South Carolina, the Ohio Gas Association, and the

Industry Trades[178] expressed general opposition to the proposal, stating that the 5-year minimum has proved effective and the more frequent surveys would not be justified by leak reduction projections, nor an improvement in pipeline safety. They expressed concern that the proposed provisions would divert manpower, resources, and funding from other proposals for monitoring and repairing leaks. Additionally, they noted the proposed changes could raise utility costs for consumers without creating a commensurate increase in safety. According to commenters, the 3-year interval would increase the financial burden of leak surveys on operators, not simply from the increased frequency of conducting such surveys, but also from hiring additional employees and from purchasing additional leak detection equipment. Other commenters, including the Fort Valley Utility Commission, the City of Toccoa, the City of LaGrange, the City of West Point, the City of Monroe, and the City of Buford opposed proposed § 192.723(c), stating that a 3-year interval is unnecessary since many leaks are identified through other means, such as reports by employees or the public. On the other hand, the Joint Environmental[179] comment supported the proposed survey frequencies for pipelines located outside of business districts.

[178] The American Gas Association (AGA), American Petroleum Institute (API), American Fuel & Petrochemical Manufacturers, American Public Gas Association (APGA), GPA Midstream Association, Interstate Natural Gas Association of America (INGAA), and Northeast Gas Association submitted joint comments (Docket Number: PHMSA-2021-0039-26350). Throughout this final rule, references to "Industry Trades" refer to this joint comment. Unless denoted as "April 2024," any reference to the Industry Trade comment is assumed to be citing the August 2023 comment. Note that INGAA also submitted a separate set of comments that are referred to individually and distinctly from the Industry Trades comment, as appropriate.

[179] The Environmental Defense Fund (EDF), Natural Resources Defense Council (NRDC), Sierra Club, and Earthjustice submitted joint comments (Docket Number PHMSA-2021-0039-26523). Throughout this final rule, references to "Joint Environment comment" refer to this joint comment. Unless denoted as "April 2024," any reference to the Joint Environmental comment is assumed to be citing the August 2023 comment.

Multiple operators expressed that the current frequency requirements are sufficient when performed in conjunction with the accelerated or additional leak surveys as required by an operator's DIMP. The Industry Trades and multiple operators concurred that 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. They recommended that PHMSA forgo this proposed change and focus instead on performance-based DIMP audits.

Picarro, Inc.[180] found that reducing the delay between surveys from 5 years to 3 years results in an emissions reduction from 80 percent to 68 percent, citing data on the frequency and flow-rate distribution of leaks on gas transmission lines from Lamb 2015 and numerous observations from their own leak survey activities. However, Picarro, Inc. estimated that the proposed change to the survey frequency would almost double the average annual cost for operators. Therefore, Picarro, Inc. suggested that it would be more cost effective for PHMSA to permit operators to leverage data from advanced mobile leak detection technology to establish their own leak investigation frequencies based on actual observations in the field. Picarro, Inc. stated that this approach would allow operators to consider the unique attributes of a pipeline, such as history and materials, allowing for a more refined survey frequency.

The Maryland (MD) Attorney General's Office, et al. expressed support for the proposed survey frequencies, adding that these would prevent leaks from going undetected for longer periods of time, alleviating serious safety and environmental concerns. Gulf Coast Helicopters,

[180] Picarro, Inc. is a private company that provides mobile leak detection technology and systems.

Inc. stated that an increased survey frequency can have a greater impact on fugitive emissions reduction than the sensitivity of an instrument or other criteria which may limit technology options and increase costs. Similarly, Alexander City Gas Department expressed support, stating that they have experienced a decrease in leak calls and after-hours call outs since adopting a 3-year frequency for leak surveys.

The New York State Department of Public Service asked PHMSA to clarify if the proposed requirements would apply to both inside and outside piping. Multiple individual operators proposed that PHMSA maintain the current 5-year frequency for inside service lines.

Definition of Business District

Multiple commenters submitted comments regarding the proposed definition of a "business district," as that term is used in § 192.723. NAPSR and PST supported PHMSA's development of a formal definition that takes into consideration population density, pipeline infrastructure, and proximity to buildings. NAPSR provided a suggested definition that read: "'business district' means an area, including residential areas, where business is conducted, that has pipeline facilities located under predominantly continuous paving or concrete that extends: (a) either from the center line of a street to a building wall; or (b) from a main to a building wall." The Joint Environmental comment supported updating the term "business district" to "human occupied district," as the term not only refers to the location where business is conducted, but where individuals congregate, such as schools, workplaces, residences, and recreational facilities.

Other commenters supported the status quo and recommended that PHMSA not provide a definition for "business district." The MD Attorney General et al. supported PHMSA giving States the authority to define the term applicable to their jurisdiction; however, they stated that should PHMSA decide to define the term, it should ensure that the definition is as broad as possible to minimize conflicts with existing State laws and practices. The Industry Trades and Philadelphia Gas Works suggested that each operator should develop their own definition based on GPTC guidance, individual operator DIMP programs, and the operator's O&M procedures. Another commenter, Asset Leadership Network, added that risk management techniques help pinpoint leak-prone piping. Atmos Energy Corporation echoed some of these comments, noting that due to diverse geographies and population densities, it would be difficult to develop a universal definition that would be functional for a variety of operating contexts. That commenter preferred that PHMSA give deference to operators to determine which pipelines operate within a business district due to operator knowledge on the subject as well as their operating environments and systems.

Leak-Prone Pipe Definition (§ 192.723(c)(3)(ii))

MDU Utilities contended that proposed § 192.723 did not clearly explain what pipe "known to leak" means and that this lack of clarity could lead to operators surveying their entire system and could detract from existing programs like DIMP. The commenter supported PHMSA linking the wording to operators' DIMP programs, which would allow operators to better concentrate their limited resources on pipelines with the highest risk to the public and environmental safety. Alliant Energy Corporate and WEC Energy found proposed

§ 192.723(d)(2) to be overly prescriptive and echoed comments for allowing operators to rely on their DIMP program for managing leak-prone pipe. The Industry Trades noted the importance of allowing operators to use a risk-based approach based on individual conditions and location, consistent with the principles of DIMP.

The PST and the NTSB requested that PHMSA provide an explicit list of leak-prone plastic pipe that would be subject to the rule. Specifically, the NTSB stated that, while PHMSA-issued guidance and advisory bulletins are useful, providing clear regulations would better promote efforts of pipeline operators to identify threats and operate their systems safely. PST urged PHMSA to remove the adjective "historic" from the phrase "historic plastics" to avoid unnecessary ambiguity, concerned that including the adjective "historic" may unintentionally exclude newer plastics that are known to leak. The Industry Trades noted that the 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.

Leak-Prone Pipe Survey Frequency

The MD Attorney General et al. supported PHMSA's proposed § 192.723(d), which would require operators to annually survey cathodically unprotected pipes as well as those pipes known to leak based on material, design, or past O&M history, as well as the proposed provision for operators to survey pipelines located outside of business districts once every 3 years. That commenter supported these proposals on the basis that the existing survey requirements allow leaks to go undetected for longer periods of time, which can present serious safety and environmental concerns. The Industry Trades opposed proposed § 192.723(d), claiming that this frequency would not reduce the risks from leaks enough to justify the increased costs for operators. They further argued that proposed § 192.723(c)(2) erodes the strength of existing DIMP requirements, which they state is a demonstrated program to address threats from corrosion and other time-dependent events. The Industry Trades also argued that operator DIMP programs already adequately eliminate methane emissions and hazardous leaks. The NY State Department of Public Service asked for PHMSA to clarify whether § 192.723(c)(2) applies to both indoor and outdoor piping, with outside piping including through-wall penetration coming into the building.

In the NPRM, PHMSA solicited comment on the value of adopting more- or less-frequent leak surveys of plastic pipe systems within this final rule, as well as adding a potential means to identify plastic pipe known to leak (e.g., via a surveillance or sampling program). The Asset Leadership Network suggested a performance standard would be more appropriate than a design standard, stating that they preferred that organizations develop internal controls to properly detect significant leaks, such as requiring the use of the Committee of Sponsoring Organizations of the Treadway Commission (COSO) internal control framework of the Government Accountability Office (GAO) Green Book.[181] Philadelphia Gas Works and the Industry Trades responded to PHMSA's solicitation and stated that the topic of vintage plastic pipe systems being leak prone is well understood due to guidance from the NTSB and PHMSA, with Philadelphia Gas concluding that there was little value to increasing the leak survey

[181] GAO Green Book. September 14, 2013. gao.gov/greenbook
This book sets the standards for an effective internal control system for federal agencies. Internal control is a process used by management to help an entity achieve its objectives.

frequency. In contrast, the Joint Environmental comment[182] contended that methane leaks from plastic pipe are 8.5 times higher than estimated by the EPA, thereby justifying an increased survey frequency.

Philadelphia Gas Works and the Industry Trades contended that historic plastics are not prone to leak in every geography and therefore requested PHMSA provide an option for operators to use a risk-based approach, based on operating condition and location, to ascertain which materials are leak-prone. Atmos Energy Corporation suggested striking the language specifying pipeline materials as well as the reference to design or past O&M history so that § 192.723(d)(2) would read as "Pipelines constructed of historic plastics with known issues." That commenter supported PHMSA requiring an annual leak survey frequency for pipelines constructed of cast iron, unprotected steel, or wrought iron, and those gas distribution pipeline systems protected by a distributed anode system, with a caveat that provides for a shorter inspection interval if required by an operator's O&M procedures or DIMP. However, for pipelines constructed with historic plastics with known issues and cathodically unprotected distribution pipelines subject to § 192.465(e), Atmos Energy Corporation supported a survey frequency of once every 3 years.

WEC Energy Group stated that a "down read" is not an indication of immediate or imminent failure. PHMSA interprets the terminology of a down read to refer to a low reading of less than 850 mv on an operator's cathodic protection survey. Specifically, WEC Energy Group and PPL Corporation suggested it would be more effective for PHMSA to require an increase to

[182] (PHMSA-2021-0039-26523).

leak survey frequencies of cathodically protected steel with deficient readings only if the deficient read is not corrected within 15 months, aligning the timeline with § 192.465(d). Similarly, another commenter, Southern Company Gas, requested striking the proposed requirement, claiming that it is duplicative with existing cathodic protection requirements.

Solicitation of Comments on Requiring Assessments Prior to Extreme Weather Events

In the NPRM, PHMSA invited comment on whether to require assessments prior to extreme weather events for operators to prepare for and prevent resulting leaks. Thermo Fisher Scientific supported requiring such assessments because extreme weather can pose a threat to a pipeline's integrity, and because assessments conducted prior to an extreme weather event encourage proactive maintenance, operational continuity, environmental protection, risk preparedness, and post-event evaluation. The commenter further noted that an increase in extreme weather events in recent years make these concerns even more paramount. On the other hand, other commenters, including Philadelphia Gas, Atmos Energy Corporation, and the Industry Trades, opposed requiring assessments prior to extreme weather events. These commenters claimed that the timing, location, and severity of extreme weather events is too unpredictable for operators to properly target in advance those areas that will ultimately be impacted by these events.

Investigating Known Leaks After Environmental Changes (§ 192.723(e)) and Extreme Weather Events and Land Movement (§ 192.723(f))

Pennsylvania (PA) State Senator Katie Muth, Physicians for Social Responsibility PA, Clean Air Council, Waterspirit, a form letter campaign, and additional individual commenters supported proposed §§ 192.723(e) and (f) but said that undertaking these surveys should not re-start the timeline for surveying. A joint comment from researchers at the Colorado State University and Southern Methodist University (CSU/SMU) similarly supported operators performing surveys after extreme weather events, explaining that leaks occurring under conditions of rain, snow, and ice can result in methane migration below the ground at a faster rate and in higher gas concentrations than under non-adverse conditions. The Industry Trades recommended that the requirement for operators to investigate leaks after environmental changes be placed at § 192.760 instead of § 192.723 and suggested that proposed § 192.723(e) is redundant with proposed § 192.760(c)(5).

MDU Utilities stated that requiring the investigation of leaks after certain environmental changes, namely ground freeze, was impractical in northern climates where entire areas of systems could be impacted by these environmental changes. Several commenters argued that proposed § 192.723(f) was too broad and could be construed as requiring operators to survey their entire system within 72 hours. Sanders Resources and the City of Thomson similarly stated that the term "extreme weather" is so broad as to make the proposed requirement impracticable and asked PHMSA to instead allow operator discretion when making determinations for these surveys. NAPSR recommended that PHMSA either define an extreme weather event or otherwise provide examples of such events.

Another commenter, WEC Energy, wrote that performing surveys after extreme weather events are routine and have not been found to create system-wide unsafe conditions. The commenter also noted that IM programs are already being used to identify threats and develop appropriate mitigating actions. Regarding leak surveys after extreme weather and land movement, the City of Cartersville Gas System (GA); City of Toccoa (GA);[183] City of Covington, Georgia; City of Sylvania, Georgia; City of LaGrange, Georgia; City of West Point, Georgia; City of Adairsville (GA); National Grid; PPL Corporation; Philadelphia Gas Works; Washington Gas; and the Municipal Gas Authority of Georgia also stated that the phrase "extreme weather and land movement" in the NPRM was unclear and overly broad. Alexander City Gas specifically requested that PHMSA provide more precise definitions of these two terms and consider defining areas and specific conditions operators must investigate. Some commenters also requested PHMSA allow operators to determine the conditions and area, rather than have it be prescriptive. Atmos Energy Corporation and the Industry Trades also requested more clarity in the definition of "extreme weather," suggesting that PHMSA define this term using similar language as that which exists in § 192.613(c). Multiple commenters explained that the vague phrasing could be construed to require operators perform a full system leak survey after each event. Two small operators, City of Adairsville Natural Gas System (GA) and the City of Douglas (GA), noted that the proposed requirement could be difficult to meet because they have limited resources, with one commenter noting that their DIMP and operator qualification (OQ) procedures already include guidance on integrity checks after extreme weather events. Another commenter, PPL Corporation, explained that the current phrasing of the proposed requirement would require operators to continuously investigate known leaks, depending on weather events, and would require a fluctuating workforce that would be difficult to hire and

[183] The City of Toccoa serves customers in Georgia and in North Carolina.

maintain. Additionally, NAPSR observed that the proposed § 192.723(d)(3) erroneously referenced § 195.463, which is not applicable to gas pipelines.

General Comments

In the NPRM, PHMSA requested comment on the appropriate leak survey frequency for gas distribution pipelines. Multiple operators, including Energy Transfer LP, the City of Sugar Hill, WEC Energy Group, Vermont Gas Systems Inc., Spire Inc., and Consolidated Edison Company, claimed that the proposed increased frequency of leak surveys would increase costs for ratepayers with no corresponding improvement to safety. Consumers Energy Company stated that it would be expensive to comply with the new leak survey standards. Consolidated Edison Company asked for PHMSA to consider the differences between an indoor service line versus a buried (exterior) service line when determining surveying frequencies and allow for a 5-year survey interval for indoor service lines.

The Joint Environmental comment supported a simplified leak survey frequency for gas distribution lines, where all lines would be subject to a 1-year survey interval. Specifically, an annual leak survey frequency would improve safety and environmental protection as more leaks would be found; simplify compliance for operators; and lead to more effective oversight and enforcement by PHMSA and state regulators. Attached to their comment was modeling demonstrating that increasing survey frequency is critical to identifying leaks that are disproportionally responsible for emissions.[184]

[184] Ravikumar, A.P and Strayer, A., Modeling Leak Detection and Repair Programs for Natural Gas Pipeline Infrastructure Using FEAST, August 2023.
(PHMSA-2021-0039-26523).

This research was led by Arvind Ravikumar and Alan Strayer at the University of Texas at Austin, where they evaluated various scenarios that examined the impact of survey frequency with equipment of varying detection thresholds on annual gas release volumes, assuming the respective leaks were then repaired per the proposed PHMSA repair criteria. For this evaluation a modified version of the FEAST[185] (Fugitive Emissions Abatement Simulation Toolkit) code, FEAST-Pipeline, was used that enabled the code to be applied to gas distribution systems.

Ravikumar and Strayer found that if gas distributions surveys were conducted more frequently than currently required by § 192.723 and equipment with sufficient leak detection sensitivity was used, there would be a reduction in annual gas emissions.[186] This was particularly true when equipment with a detection threshold that is improved over traditional handheld device sensitivity is used. As an example, as compared to a baseline scenario using traditional handheld detection with a sensitivity of 0.5 kg/hr (100 percent probability of detection) performed at five-year intervals with legacy repair rules, surveys conducted on three-year intervals with detection equipment having improved sensitivity of 0.2 kg/hr probability and new repair rules result in an approximately 60 percent reduction in annual emissions (tons CO_2e/year).[187]

The authors note that gas distribution leaks are characteristically small and numerous. Therefore, the use of equipment without sufficient leak detection sensitivity (e.g., 1 kg/hr and higher) results in an overall increase in annual gas emissions even if leak surveys are conducted more frequently

[185] https://www.eemdl.utexas.edu/feast.

[186] Ravikumar, A.P and Strayer, A., Modeling Leak Detection and Repair Programs for Natural Gas Pipeline Infrastructure Using FEAST, August 2023 (PHMSA-2021-0039-26523) Appendix A pp. 13.

[187] Ravikumar, A.P and Strayer, A., Modeling Leak Detection and Repair Programs for Natural Gas Pipeline Infrastructure Using FEAST, August 2023 (PHMSA-2021-0039-26523) Appendix A pp.21.

than the baseline scenario. For example, as compared to the same baseline scenario using traditional handheld detection with a sensitivity of 0.5 kg/hr (100 percent probability of detection) performed at five-year intervals with legacy repair rules, surveys conducted on three-year intervals in non-business districts and annually in business districts using detection equipment with sensitivities of 1, 3, 10 and 30 kg/hr probability of detection and new repair rules resulted in overall increases in annual emissions for each case (tons CO_2e/year).[188] In other words, establishing a high detection threshold results in lower emissions reductions regardless of survey frequency since the survey method will be unable to detect even relatively large leaks on gas distribution lines.

The Asset Leadership Network opposed PHMSA's codification of a specific schedule for leak surveys and stated that operators should have the liberty to determine what is an effective survey interval rather than following an arbitrary schedule that may not prevent unwanted leaks. The commenter stated that using key performance indicators (KPIs) would indicate whether an operator has an effective leak detection program. Thermo Fisher Scientific supported PHMSA requiring annual leak surveys of distribution mains, as this would lead to methane emission reductions upwards of 1.2 million metric tons per year. Multiple commenters, including the Industry Trades, Spire Inc., and National Grid, opposed the proposed prescriptive leak survey frequencies and preferred leveraging DIMP requirements and outcomes, as the programs are customized to operators' pipelines and operating conditions.

[188] Ravikumar, A.P and Strayer, A., Modeling Leak Detection and Repair Programs for Natural Gas Pipeline Infrastructure Using FEAST, August 2023 (PHMSA-2021-0039-26523), Appendix A pp. 15.

Gulf Coast Helicopters submitted a general comment in support of more frequent leak surveys conducted using less sensitive leak survey equipment that is simpler and cheaper for operators to use.

Physicians for Social Responsibility PA requested that PHMSA require methane detection systems in all dwellings to reduce the risk of explosions and to collect monitoring data.

An individual commenter, Marc Huestis,[189] stated that the proposed changes in § 192.763 should not apply to in-home methane detector technology and interior building service line inspections upstream of gas meters that are subject to PHMSA jurisdictional authority. The individual commenter argued that the proposed requirements will significantly hamstring the widescale deployment of in-home methane detector technology. The commenter[190] recommended that the agency apply its regulatory jurisdiction authority to require gas operators to use in-home methane detectors to continuously monitor jurisdictional interior service lines in order to prevent events, save lives, and reduce fugitive methane emissions.

NAPSR suggested that PHMSA move the phrase "the operator's operations and maintenance procedures, or the operator's integrity management plans under part § 192, subpart P" from this section to § 192.605, make it a blanket statement, and include a reference to subpart O.

The Industry Trades commented that operators currently survey coated steel and plastic mains on a 5-year cycle and that the proposed 3-year cycle for these mains coupled with the

[189] (PHMSA-2021-0039-24332) August 16, 2023.
[190] (PHMSA-2021-0039-24332) August 16, 2023.

proposed 6-month effective date of the rule would result in many operators being automatically out-of-compliance with the new frequency. Commenters also suggested that PHMSA should provide a 3-year effective date for the final rule, as the 6-month timeframe proposed in the NPRM is not realistic or achievable.

3. GPAC Deliberation Summary

On November 28, 2023, Committee discussion of NPRM proposals for gas distribution leak surveys pursuant to § 192.723 began with PHMSA's summary presentation of the proposed regulatory language and its supporting reasoning (including a discussion of its cost and benefits), and an overview of significant comments from stakeholders on the proposal. After this, members of the public provided additional commentary on the proposals. Among the stakeholders providing feedback related to gas distribution leak surveys were numerous individuals on behalf of distribution operators, an individual representing NAPSR, and an individual representing a public interest pipeline safety advocacy organization. Multiple representatives from the gas distribution industry opposed the proposed prescriptive leak survey frequencies, asserting that DIMP was sufficient as it requires operators to identify threats, manage risk, and implement measures, which was a stance echoed their written comments. The pipeline safety public interest advocate supported the proposed leak survey frequency, stating it would increase safety for people and the environment. Two people representing a distribution operator indicated that their indoor service lines they are responsible for have extremely low leak rates and that any increase in survey frequency will not only increase burden to customers who must provide access to private property, but also increase costs for ratepayers. Multiple commenters opposed the proposed survey requirements after extreme weather events. A commenter from a northern state shared that conducting a survey after an extreme weather event should count as a periodic leak survey. Commenters during this public comment period cited the lack of specificity in what conditions would activate the extreme weather survey; the projected cost burden on consumers; and the increased human capital required to comply with the proposed requirement.

After comments from stakeholders were received, the Committee held a detailed discussion to address the proposed gas distribution leak survey frequency. A GPAC member representing industry opposed increasing the leak survey frequency on non-leak-prone pipe in non-business districts, as there are few leaks, and the member generally supported a risk-based approach. A Committee member representing the government preferred that operators devote limited resources to fixing known leaks, whereas a GPAC member representing the public argued that searching for leaks more frequently will likely yield more leaks discovered and that is a good thing, serving the goal of improving safety and protecting the environment.

There was desire by Committee members of all representations to distinguish between the survey frequencies for inside and outside pipe. A member representing the industry wanted to ensure that the Committee was making data-driven recommendations and that any decision be integrated with DIMP requirements. A Committee member representing the public shared that a small number of large leaks contribute to the majority of the emissions, and therefore it is imperative to find these leaks quickly and cost-effectively. This member concluded that when choosing between high-sensitivity technology and a higher survey frequency, a higher survey frequency should be selected, noting that improving the sensitivity of technology will only assist in detecting smaller leaks. A GPAC member representing industry acknowledged that leak-prone pipe is the cause of many large leaks and a large fraction of the total gas emission volume and supported an annual leak survey for leak-prone pipe. During individual remarks, Committee members addressed numerous topics, such as a competing tension between finding new leaks and fixing existing leaks, the prioritization of reducing emissions over the protection of life and property, odorization, and the unique positionality of States that go beyond the Federal minimum.

The Committee discussed survey frequencies for indoor piping composed of leak-prone materials. One member asserted that the difference between sending a utility worker out to survey a pipeline every 3 years versus every 5 years was minimal. This member noted that, while exceptions to the frequency may be appropriate if there are existing State programs addressing indoor piping, altering leak detection frequencies inside buildings generally would not make a big difference. Another member stated that forces and reactions in the soil have the most impact on whether pipes are leak-prone, for example, frost heave, soil shifting, and chemical reactions with surrounding soil, and these factors do not affect indoor pipe. A third member stated that in their view, indoor piping is not leak-prone, while a fourth member suggested that the Committee defer to PHMSA's expertise in determining the proper leak survey requirements for indoor versus outdoor pipe. A fifth Committee member suggested that indoor piping may merit more frequent leak surveys, since the primary means of detecting leaks, which is customers smelling odorants, is ineffective for the almost 1 in 4 Americans over the age of 40 that have experienced some alteration in their sense of smell. That Committee member further observed that over 3 percent of Americans have no sense of smell at all, so it is important for PHMSA to consider the limitations of odorization for certain segments of the population. A Committee member encouraged the agency to look at comments from Con Edison and the NY Department of Public Service, as these letters addressed this topic. Another Committee member requested that PHMSA clarify which material types it considers leak-prone inside of buildings.

At length, Committee members discussed leak survey frequencies for non-business districts and whether leak survey frequencies should be incorporated into the existing DIMP requirements, and if so, how to do so. Members raised serious concerns of how to marry the proposed leak survey frequencies with existing DIMP requirements, which industry and government GPAC members stated has been an effective risk-based approach. A member representing industry expounded on how DIMP data is the core of risk management, and it drives an operator's program, inspections, and process. A member representing industry stated if DIMP data demonstrates the need for additional leak surveys, then that should dictate the frequency of additional surveys rather than prescriptive requirements. A member representing the government noted that, for large operators, DIMP is an important and valuable tool; however, for small operators, DIMP is not an effective program because they are unable to draw meaningful conclusions from their data.

A member representing the public stated that an increased leak survey frequency would not only help operators find more leaks, but also would increase safety for rural communities. Furthermore, they noted that 13 States, in addition to the District of Columbia, require that leak surveys be conducted at a higher frequency than what is prescribed by the current Federal regulations. A member representing the industry supported stringent leak survey requirements in high-risk areas; however, the member opposed stringent leak survey requirements in lower-risk areas, stating there are more diverse circumstances. Another Committee member representing industry supported an annual survey on leak-prone pipe regardless of whether it was in a business district or not.

A member representing the public reiterated that increased surveys result in operators discovering more leaks and stated that operators should focus on mitigating and repairing the highest-emitting leaks, rather than addressing every leak an operator finds. Another member representing the public noted that nothing precludes operators from using DIMP to prioritize leak detection and management after the Federal minimum is met. A member representing the industry stated that leaks are found in leak-prone areas and that in non-leak prone areas, there are not increased leak rates. A member representing the public explained that, while the number of leaks per mile for non-leak prone pipe is lower than that for leak-prone pipe, this shows an incomplete picture because there are more miles of non-leak prone pipe. Therefore, the total number of leaks is larger from non-leak prone pipe, and some of them will be large emitters.

Members representing both the industry and the government discussed a waiver or special permit process from which an operator would seek a 5-year survey interval, but ultimately there was concern about undergoing an administrative waiver process. A member representing the public asked what standard would be used to assess whether an operator qualified for a 5-year survey interval and proposed that it be an equivalent level of safety or higher for people and the environment. A member representing the industry supported having PHMSA oversee the authority of the States to regulate such a standard.

4. GPAC Recommendation

The Committee unanimously determined that the requirements at § 192.723 related to gas distribution pipeline leak surveys were technically feasible, reasonable, cost-effective, and practicable, if PHMSA adopted the following recommended changes and considerations in the final rule:

- Consider an alternative interval frequency for indoor piping consistent with the discussion of the GPAC.
- With respect to leakage surveys of leak prone pipe inside of buildings, consider and address, as appropriate, comments from NAPSR, Committee members, and the public on the survey frequency for indoor piping and whether leak-prone pipe based on material includes piping inside of buildings.
- Finalize a 3-year leak survey interval for outdoor gas distribution pipelines outside of business districts. The Committee also recommended that this interval could be extended to 5 years if the operator, using leak data from its DIMP program, obtained appropriate Federal or State agency approval. The Committee recommended that such agency approval would evaluate whether a 5-year interval would provide an equivalent or greater level of safety and environmental protection.

In summary, the majority of the Committee deliberation centered around determining leak survey frequencies for leak-prone materials inside buildings and the leak survey frequency for pipelines located outside of business districts, and the Committee's recommendations reflect this. With respect to the leak survey frequency for pipelines in non-business districts, Committee members wanted operators to have flexibility to continuously improve. The suggestion for operators to proffer DIMP data to decrease the frequency of leak surveys in non-business districts is structured to motivate an operator to have an effective leak management system. The Committee ultimately deferred to PHMSA's expertise regarding determining whether leak-prone pipe materials were also prone to leak in indoor environments as well as determining the leak survey frequency for indoor piping in non-business districts.

5. PHMSA Response

The NPRM explains in section IV.A that PHMSA understood its proposed approach would satisfy the terms of the section 113 mandate, reinforce the self-executing mandate in section 114 of the 2020 PIPES Act, exercise PHMSA's public safety and environmental safety authority at 49 U.S.C. 60102(a) through (b), and yield significant public safety and environmental benefits. PHMSA's regulations, prior to this rulemaking, were silent regarding the required minimum performance of leak detection equipment used in leak surveys on gas distribution pipelines, thereby forfeiting the improved efficacy of commercially available advanced leak detection equipment in detecting leaks during any leak survey performed—whether inside or outside a business district. PHMSA also proposed to increase the frequency of leak surveys operators of gas distribution pipelines outside business districts, including residential areas in order to help ensure operators detect, and therefore repair, leaks before significant consequences to public safety and the environment can occur. DIMP requirements have failed to adequately address these concerns. The NPRM explained that DIMP regulations and guidance afford operators broad discretion in determining the manner and frequency of leak surveys conducted beyond the minimal, baseline prescriptive requirements in § 192.723, thereby potentially inhibiting effective regulatory backstopping of operator practices; and notwithstanding that all gas distribution pipelines are subject to IM requirements, there were nearly 400 incidents on gas distribution pipelines attributed to leaks over the 10-year period between 2010 and 2020.[191] Noting that FEAST modeling data discussed at the 2021 EPA Methane Leak Detection Technology Workshop strongly supported the intuitive relationship between leak detection efficacy and leak survey frequency,[192] the NPRM consequently proposed that operators would focus their limited resources to perform leak surveys on distribution pipelines where an increased survey frequency would yield greater reductions in public safety and environmental risks. Specifically, PHMSA proposed for gas distribution pipelines outside of business districts the same, default 3-year frequency for leak detection surveys that RSPA three decades earlier had adopted for the enhanced protection of distribution pipelines without cathodic protection.[193] And those gas distribution pipelines outside of business districts with materials, design, or operating history that made them particularly susceptible to leaks would need to conduct leakage surveys on the same annual basis as the PSR have required since 1970

[191] 88 FR 31890 at p. 31908 – 10.

[192] 88 FR 31890 at p. 31926. Leakage surveys have been the principal regulatory approach for identifying leaks and anomalies on pipelines since the inception of the Pipeline Safety Laws in the late 1960s. See Hazardous Materials Regulation Board, "Final Rule: Transportation of Natural and Other Gas by Pipeline: Minimum Standards" 35 FR 13248 (Aug. 19, 1970).

[193] See RSPA, "Leakage Surveys on Distribution Lines Located Outside Business Districts," 58 FR 54524 (Oct. 22, 1993).

for systems inside business districts. Similarly, and consistent with PHMSA guidance and lessons learned warning operators of the risks to pipeline integrity and public safety associated with extreme weather events and environmental phenomena, the NPRM proposed operators perform leak surveys on gas distribution pipelines soon after those events occur. PHMSA preliminarily concluded in the NPRM that risk-informed enhancements to the gas distribution leak survey requirements described above would, when considered alongside the leak detection equipment and ALDP performance standards provided for elsewhere in the rulemaking, improve the number and efficacy of leak surveys, thereby ensuring the timely and effective identification and repair of such leaks on gas distribution pipelines in a way that significantly reduces public safety and environmental risks.

The administrative record developed in response to the NPRM, summarized above at section III.A.2, however, highlights stakeholder concerns with PHMSA's proposed approach. First, industry stakeholders and their trade associations who submitted comments on the NPRM and participated in GPAC discussions generally criticized PHMSA's proposal as offering little meaningful public safety and environmental benefit at greatly increased cost. Even leak detection equipment vendors (e.g., Picarro, Inc.) who submitted data corroborating PHMSA's preliminary finding that the proposed enhanced leak detection survey frequency would yield greatly improved efficacy and timeliness in operators identifying leaks cautioned that those benefits would come at increased costs for operators. Industry stakeholders and their trade associations, moreover, warned that those increased compliance costs could in fact prove zero-sum with other measures—in particular, DIMP compliance efforts—characterized as more effective in protecting public safety and the environment than PHMSA's proposed enhanced leak survey requirements. Second, several stakeholders (generally representing the industry) submitted comments and raised, during the GPAC discussions, implementation concerns arising from allegedly unclear or overbroad proposed regulatory language (e.g., the definition of "business district;" the content of "pipelines known to leak;" and the scope of "extreme weather") determining whether a gas distribution pipeline would be subject to increased survey frequencies. And as explained in detail in section III.A.3 and III.A.4, the GPAC discussed at length those industry stakeholder concerns, resulting in recommendations endorsing PHMSA's proposed default 3-year frequency for gas distribution pipelines inside business districts, albeit with mechanisms allowing for reduced leak survey frequencies for gas distribution lines located inside buildings and for operators with robust DIMP practices.

Based on its review of the administrative record, including the analysis in section IV.A of the NPRM, which is hereby incorporated in this final rule, PHMSA, in this final rule, has adjusted its proposed leak survey requirements for gas distribution lines to reduce compliance costs and better tailor performance standards to improve public safety and reduce the environmental impact of leaks on those facilities. Two January 2024 explosions on the Atmos-operated gas distribution system in Jackson, MS, that occurred after the operator had previously identified, but did not repair, a grade 2 leak and a grade 3 leak, respectively, underscore that even grade 3 leaks can be a leading indicator for near-term catastrophic incidents.[194] Meanwhile, peer-

[194] NTSB, Investigation No. PLD24FR003, "Atmos Energy Corporation Natural Gas-Fueled Home Explosions and Fires" (Feb. 14, 2024).

reviewed studies,[195] FEAST modeling results,[196] and analysis by leak detection equipment vendors[197] (Picarro, Inc.) specializing in leak surveys on distribution lines each lend additional support to PHMSA's reasoning in the NPRM that leak identification efficacy—and by extension, reduction of public safety and environmental risks via reduced emissions—is strongly correlated to survey frequency. As explained in greater detail in the discussion of the ALDP performance standard in section III.D.5, leaks on gas distribution pipelines typically exhibit smaller release rates and are therefore harder to detect compared to gas transmission or gathering pipelines; therefore, more frequent leak surveys provide additional opportunities to successfully identify leaks that a single survey may overlook. Indeed, GPAC members with expertise in natural gas pipelines emissions, leak detection technology, and leak survey methods identified leak survey frequency as a critical factor in improving leak detection efficacy on gas distribution lines.[198] Further, the NRPM analysis, GPAC discussions, and incident data each underscore the value for emissions and public safety risk reduction that would occur by adopting PHMSA's proposed approach of enhancing the leak survey frequency on certain pipelines outside business districts that are at greater risk of leaks, as well as any gas distribution pipeline exposed to external stresses, which create or exacerbate leaks, because of extreme weather or natural disasters.

[195] MacMullin, Sean, and François-Xavier Rongére, "Measurement-based emissions assessment and reduction through accelerated detection and repair of large leaks in a gas distribution network," 17 Atmospheric Environment: X. 100201 (Jan 2023).
[196] EDF FEAST Modeling Slide deck at 8-9.
[197] Picaro at 6-7.
[198] Ravikumar. GPAC Transcript at 147 (Nov. 28, 2023).

Increased survey frequencies, however, can come at increased cost. Apart from reducing the compliance costs of each survey by adjusting performance standards to, among other things, allow operators to use less-sensitive leak screening survey equipment, this final rule reduces costs anticipated in the NPRM by limiting increased leak survey frequencies to those gas distribution pipelines outside of business districts where the design, material, or operating history of those pipelines mean they are more likely to leak. This final rule similarly addresses stakeholder compliance cost concerns from ambiguous language in the NPRM's proposal for an enhanced survey frequency following natural disasters and extreme weather events by clarifying that regulatory language. PHMSA has also decided to not adopt other potential regulatory amendments (e.g., pertaining to the definition of "business district") mentioned in the NPRM in response to stakeholder implementation concerns. These adjustments from the NPRM to enhance the efficacy and reduce the costs of leak surveys on gas distribution lines are consistent with the GPAC discussion and recommendations acknowledging the value for emissions reduction and public safety of an increased leak survey frequency outside of business districts and will help ensure that the regulatory amendments in this final rule complement and backstop, rather than distract from, operators' implementation of their DIMPs. PHMSA therefore expects these risk-based refinements in this final rule's leak survey requirements for gas distribution pipelines, when coupled with mutually reinforcing provisions elsewhere in this final rule, will yield significant improvements compared to the status quo and the NPRM alike in the timely, cost-effective identification and repair of leaks entailing the greatest public safety and environmental risks.

Leak Surveys for Non-Leak Prone Pipe Outside of Business Districts (§ 192.723(c)(1))

This final rule diverges from the Committee's recommendation for operators to perform leak surveys outside of business districts at least once every 3 calendar years, at intervals not exceeding 39 months. Instead, this final rule retains the existing 5-year default survey interval, with a maximum interval between surveys not to exceed 63 months, for all non-leak-prone pipe (i.e., pipe that does not meet any of the categories listed in § 192.723(c)(2)). For leak prone pipe that meets one of the categories listed in § 192.723(c)(2), the survey interval is generally one year, which is discussed further below. PHMSA has decided to retain the existing 5-year default survey interval considering concerns raised by commenters, Committee discussions, and PHMSA's cost-benefit analysis in the final RIA. As discussed above, several commenters expressed concern that the additional costs associated with more frequent leak surveys would not be justified by the limited benefits achieved on pipe that is not prone to leaks. As discussed in the RIA, PHMSA considered the incremental costs and benefits of the final rule relative to the NPRM proposal, where leak-prone pipe would be surveyed at a 1-year interval, but non-leak-prone pipe would continue to be subject to the current 5-year leak interval. PHMSA estimates that the final rule will be more cost-effective than the original proposal due to reduced survey costs on pipelines that data indicates are less susceptible to leakage. PHMSA also found that this alternative will help address other concerns raised by commenters and the GPAC: namely, that operators already use DIMP to target leak surveys and other efforts towards system-specific higher-risk pipe, and that a 5-year survey interval may be appropriate for pipeline facilities that have been demonstrated to not be susceptible to frequent leaks. This revised survey interval also addresses concerns from the GPAC and public comments about leak surveys of pipelines located inside of buildings due to the difficulty obtaining access to such piping, which is typically located on private property. In fact, this approach is largely consistent with the GPAC's recommendation that PHMSA consider whether to allow operators to extend the applicable leak survey interval up to 5 years, based on leak data from an operator's DIMP, with approval, if appropriate, from PHMSA. PHMSA's decision to retain the existing 5-year default survey interval was also made considering the other elements of this final rule setting forth leak grading, leak repair, and ALDP requirements. As explained further in sections III.D, III.E, III.H, III.I, and III.J, operators will be required to take action to eliminate existing leaks on their pipeline systems and aggressively find and fix new leaks to significantly reduce emissions. PHMSA encourages operators to conduct more frequent leak surveys on distribution systems as appropriate and notes that surveys or other efforts are required when identified under an operator's DIMP program as a preventative and mitigative measure for higher-risk segments or segments that are more susceptible to leakage. Operators must continue to follow their O&M procedures and other plans and procedures required by part 192, including where such procedures require more frequent inspection intervals situations such as where, through DIMP or other assessment tools, operators determine that more frequent surveys are necessary to ensure the integrity and safety of their pipeline. In the NPRM, PHMSA explicitly reiterated this in § 192.723(c), stating that a shorter survey frequency may be "required either by paragraph (d) of this section, the operator's O&M procedures, or the operator's integrity management plans under part 192, subpart P." However, public comments suggested this language had the potential to confuse stakeholders; NAPSR expressed concern that other part 192 requirements didn't have the same language referring to operator procedures, and they suggested that PHMSA mentioning that operator's plans and procedures are binding in this context incorrectly implies that they are not binding in others. Therefore, PHMSA has removed this phrase from this final rule for clarity.

Definition of Business District

The Committee discussed the topic of defining a business district but did not provide a specific recommendation to PHMSA. One member argued that the business district concept was intended to denote areas of higher risk and opined that it is difficult to enforce because it is a subjective term. Another member suggested using a term, such as "human-occupied district," to more accurately account for areas where humans congregate at a higher density. A third member supported striking the word "commerce" from the definition, reasoning that a focus on commercial activity unintentionally excludes areas with dense residential populations, such as apartments, institutions, venues, or gathering places, if there is no exchange of commodities or services. A fourth Committee member recommended that PHMSA rely on GPTC guidance when updating the definition. A public commenter, Matt Smith, who had previously participated in a NAPSR working group related to the definition of "business district," said that the focus on traditional business districts was an attempt to target areas of higher risk. That working group identified two areas with increased risk that warrant more frequent leak surveys—(1) areas of wall-to-wall paving and (2) locations with populations with limited ability to evacuate in an emergency, such as prisons, hospitals, or schools. Ultimately, that working group suggested changing the name of what these areas are called to elevated risk areas.

PHMSA appreciates the comments it received on this topic, especially those from PHMSA's State partners, regarding the implications of this term in their respective States. PHMSA was concerned about unintentional consequences on existing requirements should the definition be changed, and ultimately decided not to provide a definition for "business district" in this final rule. However, the agency will consider the received comments and feedback when deciding whether to propose a definition for "business district" in a future rulemaking.

Leak-Prone Pipe Definition (§ 192.723(c)(3)(ii))

In response to concerns from MDU Utilities, WEC Energy, and Alliant Energy Corporate regarding a perceived lack of clarity in the meaning of pipelines "known to leak" in the PIPES Act of 2020, PHMSA is providing in this final rule examples of what materials are historically known to leak, such as cast iron, unprotected steel, wrought iron, and certain specified vintages of plastics with known issues. A pipeline may be known to leak based on its material, design, or past O&M history. The list in § 192.723(c)(2) is not exhaustive, and other types of pipelines may become "known to leak" in the future as operators and regulators continue to collect data on pipeline leaks. PHMSA encourages operators to continue to use DIMP in concert with the requirements in § 192.723(c)(2)(ii) to ensure the safe operation and maintenance of pipelines made of materials known to leak. Operators should define pipelines known to leak in their O&M procedures in accordance with section 114 of the PIPES Act of 2020.[199] Additional analysis from

[199] PHMSA, "Pipeline Safety: Statutory Mandate to Update Inspection and Maintenance Plans to Address Eliminating Hazardous Leaks and Minimizing Releases of Natural Gas from Pipeline Facilities," 86 FR 31002 (June 10, 2021) (ADB-2021-01).

DIMP, such as observing the proportion of leaks from certain materials, may help operators discover additional pipeline materials known to leak on their systems in the future.

PHMSA appreciates the concern raised by the PST regarding the potential for leaks on vintage or future plastic materials that are not historically leak-prone. While this final rule adopts the statutory language from the PIPES Act of 2020 listing examples of leak-prone materials, that list is not exhaustive. Further, the phrase "pipelines known to leak based on their material […] design, or past operating and maintenance history" at § 192.723(c)(2)(ii) will include all pipe known to leak based on O&M history, including plastic pipe, regardless of whether such pipe is "historic." Should new trends and data about pipeline leaks by material emerge, PHMSA may update its guidance regarding leak-prone plastic pipe and other leak-prone materials in the future.

In keeping with this need for future flexibility, PHMSA declines to provide an exhaustive list of pipe materials with known issues in this final rule. Instead, operators should review previous PHMSA and State regulatory actions and industry technical resources identifying systemic integrity issues from pipe that is either composed of particular materials, manufactured at particular times by particular companies, or manufactured pursuant to particular processes. For example, as noted in the NPRM, in 2007, in response to NTSB findings and data collection performed by the Plastic Pipe Database Committee (PPDC), PHMSA issued Advisory Bulletin ADB-07-01.[200] That advisory bulletin called operators' attention to cracking issues on pipe and components manufactured by Century Utility Products, Inc.; low-ductile inner wall "Aldyl A"

[200] "Pipeline Safety: Updated Notification of Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe-Advisory Bulletin ADB-07-01," 72 FR 51301 (Sept. 6, 2007).

piping manufactured by Dupont before 1973; polyethylene gas pipe made from PE 3306 resin; Delrin insert tap tees; and caps made of Celcon (polyactal) on Plexco service tees. Similarly, operators can refer to State pipeline safety regulatory actions, PHMSA pipeline failure investigation reports, and NTSB findings to help determine whether a certain type of pipe is at a higher risk of leaks. Additionally, operators can leverage industry efforts and resources to help determine whether a certain type of pipe is known to leak. For example, the PPDC publishes data submitted by program participants that incorporates information regarding investigations of materials of concern or potential concern.[201] PHMSA expects that a reasonably prudent operator can determine whether particular pipe materials in its distribution systems are leak prone based on the aforementioned materials, other authoritative resources, and their own design expertise and O&M history.

Leak Surveys for Leak-Prone Pipe (§ 192.723(c)(2))

In this final rule, PHMSA has largely adopted the proposed requirement for annual leak surveys of distribution lines known to leak based on their material (including cast iron, unprotected steel, wrought iron, and plastics with known issues), design, or past O&M history. Operators must survey leak-prone pipes at least once per calendar year for pipelines located inside a business district and for outdoor piping in non-business districts. For pipelines inside of buildings, PHMSA recognizes the concerns raised by the GPAC and commenters that such lines are both less susceptible to some causes of leakage and more difficult to survey. Therefore, in

[201] APGA, "Plastic Pipe Database Collection Initiative," apga.org/programs/plasticpipedata (last accessed Aug. 29, 2024).

this final rule, PHMSA is requiring operators survey pipelines in non-business districts at a 5-year frequency regardless of whether the piping is located inside or outside of buildings. Based on the Committee's recommendation and public comments, this final rule requires that indoor piping in non-business districts be surveyed at least once every 5 calendar years, at intervals not exceeding 63 months, as these pipelines are less exposed to conditions that would make these materials leak prone and they are harder to survey due to their location inside of buildings. For leak-prone pipelines in non-business districts, operators must survey those pipelines at least once per calendar year if those pipelines are located outside of a building.

Annual report data demonstrates the necessity of increasing leak survey frequency for leak-prone pipe. Based on gas distribution annual report information submitted by operators for calendar years 2010 to 2023, PHMSA calculates a yearly average of 0.16 incidents, including 0.0995 leaks per 1,000 miles of cast-iron and wrought-iron pipe, with a corresponding 0.0910 incidents including 0.0305 leaks for steel pipe.[202] On average, the rate of incidents for cast-iron and wrought-iron pipe is almost double that of steel pipe, and the rate of leaks is almost triple. In 2022, there were 0.24 leaks per 1,000 miles of cast-iron and wrought-iron pipe, whereas the equivalent rate for steel pipe was 0.015, translating to cast-iron and wrought-iron being 15 times more likely to incur a leak per mile of pipe. Notably, the total mileage of cast-iron and wrought-iron pipe has more than halved since 2010, leading to greater variation in per-mile numbers, such

[202] U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration's Annual Report Data from August 5, 2024.

as in 2019 when steel pipe overtook cast-iron and wrought-iron pipe in both incident and leak rates for one year.

More frequent leak surveys for leak-prone pipe materials are necessary due to the increased propensity of those materials to leak, and PHMSA's proposal to require operators annually survey such leak-prone materials was widely supported by commenters, Committee recommendations, and PHMSA's cost-benefit analysis. The annual leak survey requirement at § 192.723(c)(2) in this final rule applies to three specific scenarios where pipelines are at a higher risk of leakage: (1) cathodically unprotected pipelines; (2) pipelines known to leak based on material, design, or past O&M history (including those that are cast iron, bare steel, unprotected steel, wrought iron, or made with certain plastics), as discussed in detail in the previous section; and (3) pipelines protected by a distributed anode system.[203] Existing DIMP regulations neither refer to leaks with the potential of hazard to the environment nor define what an effective leak management program is. Therefore, this final rule builds a more robust leak survey regime by not only taking into consideration whether a pipeline is or is not in a business district but also considers the risk factors of certain pipelines.

PHMSA appreciates the feedback on the value of more- or less-frequent leak surveys of plastic pipe and will take it into consideration when determining whether to make further amendments to the leak survey requirements in future rulemakings. In response to commenters'

[203] West Virginia University, "Appalachian Underground Corrosion Short Course: Intermediate Course" at 3-2 (Apr. 11, 2017), https://aucsc.com/bia/AUCSC_Intermediate2017.pdf ("Distributed anode beds are used to protect sections of pipelines which have poor coating or which are bare. They are also used for localized protection and in areas where shielding does not allow the current from a remote anode bed to reach the structure.").

concerns regarding certain historic plastics not being prone to leaking in all geographies, this rulemaking finalizes a more frequent leak survey interval for certain pipelines because they are more susceptible to leaks. PHMSA issued Advisory Bulletin ADB-07-01[204] in 2007, which highlighted cracking issues with certain historic plastics. While PHMSA's Advisory Bulletin and the NTSB investigative report[205] that it references state that the public safety hazards from these failures are likely to be limited to locations where stress intensification factors exist, soil and other environmental conditions are not the only causes of excessive strain on a gas pipeline system; previous stress-related incidents on plastic pipelines have been caused by inadequate design and construction practices or environmental conditions independent of prevailing soil and climate conditions. Notably, in that investigative report, the NTSB found that a fatal gas distribution pipeline incident in New York, NY, on March 12, 2014, found that a defective joint on a plastic distribution main was subject to excessive stress caused by the previous failure of an adjacent sewer pipe—a threat independent of local soil and climate conditions.

In response to commenters' desire to permit operators to rely on DIMP for determining leak survey frequency, the leak-prone materials listed in the PIPES Act, such as cast-iron mains, have been repeatedly demonstrated to be vulnerable to integrity failures that result in incidents and emissions. For example, despite cast and wrought iron pipelines representing only 1.2 percent of main miles in gas distribution annual reports for 2023, approximately 7.8 percent of

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[204] "Pipeline Safety: Updated Notification of Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe-Advisory Bulletin ADB-07-01," 72 FR 51301 (Sept. 6, 2007).

[205] NTSB, Accident Report PAR-15/01, "Natural Gas-Fueled Building Explosion and Resulting Fire, New York City, New York; March 12, 2014" (June 9, 2015), ntsb.gov/investigations/AccidentReports/Reports/PAR1501.pdf. Pg. vii.

incidents that occurred on gas distribution mains between 2010 and 2023 occurred on pipelines made of cast iron, according to PHMSA incident report data. Similarly for the U.S GHGI the EPA adopts an emissions factor of 1,157 kg of methane per year for leaks from cast iron gas mains, over 40 times higher than the emissions factor of 28.8 kg/mi per year for leaks from plastic mains.[206] For pipe materials that are not explicitly listed as leak prone, operators are required to have procedures to identify such materials to comply with the self-executing portions of section 114 of the PIPES Act of 2020.

PHMSA appreciates the comments stating that a "down read" is not an indication of an immediate or imminent failure. In this final rule, PHMSA has clarified that, for segments with cathodic protection deficiencies, operators must conduct an annual leak survey in accordance with § 192.723(c)(2)(iii) until the operator remediates the cathodic protection deficiency on the pipeline segment. When the operator has addressed the cathodic protection deficiency on the pipeline segment, the operator may return the segment to a 3-year leak survey interval in accordance with § 192.723(c)(1).

Survey Frequency for Indoor Piping Outside of Business Districts

As previously noted, PHMSA is finalizing a 5-year leak survey frequency for indoor distribution piping outside of business districts in this rulemaking, in accordance with the GPAC's recommendation to consider an alternative interval from the proposed 3-year survey

[206] EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2022, Annex 3.6-1 (Apr. 11, 2024). Tables 3.6-2 and 3.6-6. Distribution mains emissions factors are derived from Lamb et al., "Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States," 49 Environmental Science & Technology 5161 (Mar. 31, 2015).

frequency. PHMSA understands the concerns raised by GPAC members and public comments that obtaining access to indoor piping, including indoor service lines that are likely inside a customer's private property, provides unique challenges for operator personnel. In addition to these factors, which affect the practicability of operators performing more frequent surveys of indoor service lines, such facilities are also exposed to fewer threats to their integrity and are therefore likely less susceptible to leaks. More specifically, indoor service lines are substantially less likely to be susceptible to environmental and external factors, such as precipitation, soil conditions, thermal expansion, earth movement, and other geological changes. While indoor piping exposed to the atmosphere can be susceptible to atmospheric corrosion, it is a rare cause of reported incidents; out of 1,429 gas distribution incidents occurring between 2010 through 2023, 3 were caused by atmospheric corrosion. Atmospheric corrosion control and monitoring requirements are in the regulations at §§ 192.479 and 192.481, and § 192.1007(b) requires operators to identify atmospheric corrosion risks under DIMP. Finally, as noted in the preamble to the January 2021 final rule titled, "Pipeline Safety: Gas Pipeline Regulatory Reform,"[207] performing atmospheric corrosion surveys and leak surveys on the same 5-year interval allows operators to combine inspection activities, which results in increased efficiency and potentially significant cost savings.[208] The leak survey requirements applicable to outdoor pipelines apply up to the outside wall of a building, and the indoor leak survey requirements apply to pipelines inside a building up to the inside wall of the building. Pipelines within walls are generally not

[207] "Pipeline Safety: Gas Pipeline Regulatory Reform," January 11, 2021 (86 FR 2210).
[208] 86 FR 2210 at pp. 2222-2225. (January 11, 2021).

accessible by leak detection equipment; however, PHMSA will allow surveys of the outside and inside piping up to the wall and probable migration paths to satisfy the leak survey requirements for such facilities. The survey frequency remains unchanged for piping located in a business district regardless of whether it is inside or outside of a building.

Solicitation of Comments on Requiring Assessments Prior to Extreme Weather Events

PHMSA appreciates the comments it received on this issue. PHMSA understands the challenge of requiring leak surveys in anticipation of extreme weather events, and PHMSA has therefore not adopted this requirement in the final rule.

Investigating Known Leaks After Extreme Weather § 192.723(d)

Leak surveys performed in response to an extreme weather event can be used to satisfy the general periodic leak survey requirement since the extreme weather and periodic leak surveys must be conducted using the same procedural and equipment requirements set forth at § 192.763. Therefore, if an operator performs a leak survey on a pipeline segment after an extreme weather event, the operator can "reset" the applicable periodic leak survey schedule for that particular pipeline segment.

In response to a comment supporting operators performing leak surveys after extreme weather events and a comment suggesting PHMSA should move the requirement for surveying after extreme weather events to § 192.760 rather than § 192.723, PHMSA has revised this final rule to more clearly delineate the requirement to perform leak surveys following extreme weather events from the proposed requirements to investigate and repair known leaks following environmental changes that could affect gas migration. PHMSA agrees that the investigation of known leaks is more appropriately addressed in the leak grading and repair requirements at § 192.760 and has moved that requirement to that section in this final rule.[209]

To address concerns from commenters that the language for the extreme weather survey requirement was overly broad, PHMSA has updated the language[210] with a more comprehensive discussion of which events would trigger the requirement for additional surveying. In accordance with commenters' suggestions, PHMSA has revised the language in this section to match the scope of § 192.613, which intends to limit leak surveys to pipeline segments that have the likelihood to be damaged due to the extreme weather or natural disaster events. These revisions address concerns regarding the overly broad application of the extreme weather leak survey requirement in the NPRM. If operators have incorporated criteria for defining events that have the likelihood to damage pipeline facilities in their IM program, continuing surveillance programs, or other procedures, those methodologies can be used to identify the events described at § 192.613. Therefore, this leak survey requirement is not in conflict with DIMP requirements.

PHMSA has similarly adopted language from § 192.613 clarifying expectations for when the survey should begin to address concerns from comments that the proposed language would require operators begin surveys before it was safe or practicable to do so. Specifically, the final rule specifies that the survey must be initiated within 72 hours after the point in time the operator determines the affected area can be safety accessed by personnel and equipment, and the

[209] See section III.R for the discussion of managing known leaks following environmental changes.
[210] The extreme weather requirements were proposed at § 192.723(f) and are now located in § 192.723(d) in the final rule.

personnel and equipment required to perform the survey are available. This change directly mirrors existing language in § 192.613(c)(2).

PHMSA agrees with the editorial comment by NAPSR regarding the erroneous reference to § 195.465 and has revised § 192.723(c)(3) to properly reference § 192.463 in this final rule.

General Comments

In response to public comments and GPAC discussion, PHMSA contends that increased frequency of leak surveys for at-risk pipe is critical in leak detection and emissions reduction efficacy. DIMP has demonstrated limited effectiveness with respect to the rate of leaks eliminated; therefore, additional policy innovation to improve public safety and protect the environment is necessary.

As noted in the NPRM,[211] DIMP regulations in 49 CFR part 192, subpart P, stipulate that gas distribution pipeline operators develop and implement an IM program. Key elements of DIMP include system knowledge, threat identification, the evaluation and ranking of risk, measures to address risks identified, performance monitoring, periodic evaluation and improvement, and the reporting of results. While § 192.1007(d) calls upon operators to repair all leaks when found or have an "effective leak management program," subpart P prescribes few specific requirements for leak management programs or criteria for determining their effectiveness. Currently, operators are only required to monitor the number of leaks eliminated or repaired, categorize those leaks by cause and material, determine whether they are hazardous, and report this data to PHMSA. Furthermore, subpart M, as currently written, does not prescribe

[211] 88 FR 31890 at p. 31908 – 10. (May 18, 2023).

specific technologies, equipment, or performance standards that operators should use to conduct leak detection surveys.

Since 1970, prescriptive leak survey frequencies have served as PHMSA's foundation for ensuring operators identify and repair leaks.[212] PHMSA's distinction between "business districts" and "non-business districts" illustrates the risks associated with pipeline leaks and the need for more frequent leak surveys and more stringent requirements in certain areas. Leak-prone materials, unprotected steel pipelines, and deficient-galvanic[213] cathodic protection systems are known risks to the integrity of a distribution system. Operators can elect to perform leak surveys on a more frequent basis as a measure identified through DIMP or other programs as a measure identified through DIMP or other programs.

PHMSA appreciates all the comments provided through the GPAC and in written public comments process regarding the effectiveness of DIMP. While the principles of IM are consistent for both gas transmission (TIMP) and gas distribution IM programs, operators can assess the integrity of gas transmission pipe integrity via inline inspection or other methods and identify anomalies to repair prior to leak or failure. TIMP is a considerably more robust and mature program than DIMP, as it was codified in December 2003[214] and has prescriptive requirements for integrity assessments, assessment frequency, timing for repair criteria, and reassessments. It is heavily weighted towards being proactive and implementing preventative measures. Due to the

[212] The first iteration of section 192.723(a) called for "[e]ach operator of a distribution [to] provide for periodic leak surveys in its operating and maintenance plan. 35 FR 13274 (Aug. 19, 1970).

[213] Overall, galvanic systems are harder to maintain in comparison to impressed current systems.

[214] 68 FR 69778. "Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines)" (December 15, 2003).

nature of distribution systems, and the fact that they are unable to accommodate in-line inspection tools, DIMP, has minimal prescriptive requirements and instead largely relies on operator initiative to repair identified leaks. The final rule establishing IM requirements for gas distribution pipeline systems was codified in 2009, became effective in 2010, and operators were expected to have their DIMP written and implemented by August 2, 2011.[215]

Despite the introduction of DIMP, and over a decade of implementation, the overall rate of leaks eliminated has remained constant over time.[216] This is concerning given the "continuous improvement" aspect of IM programs. As mentioned in the NPRM for this final rule, from 2010 to 2023, there were 435 reported incidents identified as "leaks" on gas distribution pipelines.[217] This demonstrates that the goal of reducing leaks, in this case leaks with serious consequences reportable as incidents has not been achieved. This was underscored by PHMSA staff during the GPAC proceedings, where staff noted that DIMP works well when an operator takes a "conservative, well-meaning approach;" however noting that not all operators will draw the same conclusions if presented with the same data.[218] Finally, the increased rates of incidents, leaks, and emissions from leak prone distribution lines, including distribution lines constructed of materials known to leak continues to be observed despite DIMP requirements being in place

[215] 74 FR 63906, Final Rule "Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines" (Dec. 4, 2009).

[216] August 8, 2024 PHMSA Data https://portal.phmsa.dot.gov/analytics/saw.dll?Portalpages&PortalPath=%2Fshared%2FPDM%20Public%20Website%2F_portal%2FGD%20Performance%20Measures&Page=Leaks. This includes leaks eliminated and hazardous leaks.

[217] 88 FR 31890 at p. 31910. (May 18, 2023). These leaks were reported as incidents and therefore the leak volume criteria of 3 MMCF or greater or other indications of significant consequences was met.

[218] GPAC Transcript at 225 – 226 (Nov. 28, 2023).

since 2009. Therefore, it is necessary for PHMSA to create a regulatory minimum leak survey frequency for all operators to follow.

Based on Committee discussion, a member representing the government stated that DIMP is a less valuable tool for smaller operators than for larger operators due, in part, to larger operators having a greater number of customers and pipeline mileage from which they can analyze and develop risk models. Ninety-two percent of gas distribution operators are small entities.[219] As previously mentioned, larger operators tend to have the capabilities and more specialized personnel to implement more robust analytical tools than are available to smaller operators. Smaller operators tend to have a more difficult time with gathering funding due to rate recovery and retaining qualified and knowledgeable subject matter experts. Thus, they are limited by available resources to execute a comprehensive analysis and efficient performance evaluation of their gas distribution system. Producing an accurate and comprehensive distribution integrity plan requires a lot of personnel hours with appropriate budget, for which, the larger operators can accommodate. Incident data demonstrates that DIMP does not result in fewer incidents from leaks on cast-iron or wrought-iron pipe, which is piping that would be subject to the increased leak survey requirements in this final rule.[220] As previously mentioned, increasing the leak survey frequency and codifying prescriptive requirements for leak-prone pipe is imperative to help ensure the protection of people, property, and the environment.

[219] Table 44 of Gas Distribution NPRM (RIN 2137-AF53) Preliminary RIA. (PHMSA-2021-0046-0043).

[220] This is a somewhat incomplete picture, because the volume of gas released to trigger an incident report is 3 MMCF. Therefore, this incident data excludes leaks that are less than this volume criterion. Based on PHMSA incident data, pulled on August 5, 2024. See phmsa.dot.gov/hazmat-program-management-data-and-statistics/data-operations/incident-statistics

PHMSA appreciates the comments it received regarding the assumptions it made in the PRIA related to gas distribution leak surveys. Based on that feedback, PHMSA has revised the applicable section of the RIA and refers readers to the RIA for a more detailed discussion. Generally, increased leak surveying will find leaks sooner, leading to quicker repairs and therefore more quickly reduce leak emissions and public safety risks. One commenter submitted evidence comparing conducting handheld surveys once every 3 years, which was the NPRM's survey timeline, and surveying every 5 years, which was the pre-NPRM survey timeline; this commenter suggested the survey timelines proposed in the NPRM would result in reduced emissions equivalent to approximately 6 fewer tons of carbon dioxide emissions per mile per year. Due to comments from the public as well as the Committee's recommendation, the final rule incorporates a general 5-year external leak survey for distribution pipelines in non-business districts per § 192.723(c) and a 1-year leak survey frequency for leak-prone pipe located in non-business districts. For pipelines located inside business districts, there is an existing annual leak survey requirement per § 192.723(b). PHMSA is finalizing a 5-year external leak survey for distribution lines in non-business districts because it found that this alternative would be more cost-effective than the proposed alternative from the NPRM. However, PHMSA has adopted a 1-year survey frequency for leak-prone pipe.

Regarding operators performing more frequent surveys (i.e., shorter intervals) with less-sensitive leak survey equipment, PHMSA believes that this final rule strikes an appropriate balance between the use of more-frequent surveys with using appropriate available technologies.

Changes to the performance standard for leak detection equipment are addressed and discussed further in section III.D.

PHMSA appreciates the comments regarding operators using continuous monitoring to perform leak surveys and regarding the performance standard for in-home methane detectors and other means of continuous monitoring. Subsequently, in this final rule, PHMSA has revised the ALDP performance standard to accommodate continuous monitoring, especially for inside of buildings, and an operator could conceivably satisfy the leak survey performance standard requirement using continuous monitoring sensors. For gas distribution systems, this final rule sets the performance standard for continuous monitoring sensors at 0.2kg/hr with a 90 percent probability of detection per § 192.763(b)(2)(i) or 500 ppm for continuous monitoring sensors inside of buildings per § 192.763(b)(3)(iii). These standards are described in greater detail in section III.D. Continuous monitoring sensors that meet that performance standard would satisfy the revised performance standard, and monitoring systems that do not meet that standard may still be considered as a preventative and mitigative measure under DIMP. PHMSA concludes that the revised ALDP performance standard it established in this final rule and retaining the status quo for the frequency of leak surveys of indoor distribution piping should address these comments. For additional discussion on the revised ALDP performance standard, please see section III.D.

In the RIA, PHMSA evaluated multiple alternatives with respect to the frequency of leak surveys for distribution lines. First, PHMSA evaluated an alternative adopting the GPAC recommendation[221] that would have required a 3-year survey interval outside of business districts (but an allowance to extend the leak survey interval for distribution lines outside of business districts up to 5 years by proffering adequate data from DIMP). PHMSA concluded that this alternative would result in higher estimated costs and lower net benefit than the final rule. Specifically, this alternative either resulted in costs that exceeded the benefits under the low-emissions scenario due to additional costs associated with either performing more frequent leak surveys of pipelines, other than those made of materials known to leak, outside of business districts or to prepare and submit notifications to request an extended survey frequency. If all lines outside of business districts are surveyed once every 3 calendar years, additional benefits from earlier identification of leaks failed to offset the increase in cost due to the relatively low frequency of leaks on such facilities. On the other hand, if all operators request and obtain an extended survey frequency benefits and costs are the same as the final rule, but with additional costs and administrative burden for operators and PHMSA associated with preparing and submitting notifications. Either case results in lower net benefits compared with the final rule. Therefore, PHMSA did not select this alternative.

Second, PHMSA considered an alternative, where distribution lines outside of business districts would be surveyed at a 3-year frequency rather than a 5-year frequency for plastic and cathodically protected steel pipe. In addition, PHMSA undertook this analysis using a 4-year frequency for these two pipes as well as another scenario of a 3-year frequency for cathodically

[221] Evaluating this alternative required PHMSA to estimate what portion of operators might qualify for less frequent leak surveys with any degree of accuracy, leading to an additional source of uncertainty.

protected pipe and 5-year frequency for plastic pipe. Ultimately, PHMSA adopted a 5-year survey interval for plastic and cathodically protected steel pipe in this final rule as this scenario has the highest net benefits across both scenarios of high or low emissions. The other alternatives considered resulted in negative net benefits or smaller net benefits.

B. Gas Transmission and Gathering Leakage Surveys and Patrols—§§ 192.9, 192.705, and 192.706

1. Summary of PHMSA's Proposal

Prior to this final rule, § 192.706 required operators to survey unodorized gas transmission and unodorized Type A and B gathering pipelines with leak detection equipment at least twice each calendar year in Class 3 locations, and at least four times each calendar year in Class 4 locations. Operators were required to survey all other gas transmission, offshore gathering, Type A and Type B gathering, and certain Type C gathering pipelines once each calendar year. In depth discussion of gas gathering is located in section III.P.

Consistent with section 113 of the PIPES Act of 2020, PHMSA proposed in the NPRM to require operators to use leak detection equipment and practices meeting the ALDP standard at proposed § 192.763 (*see* section III.D) when performing leak surveys on most onshore gas transmission and Types A, B, and C gathering pipelines. The proposal allowed operators to conduct leak surveys using human or animal senses for offshore transmission and gathering pipelines below the waterline (including platform risers up to the waterline), because leaks on submerged offshore pipelines are visibly conspicuous due to bubbles or a sheen of gas condensate on the water's surface. However, PHMSA did propose to subject offshore platform piping and riser piping above the waterline to the same equipment and survey requirements as onshore gas transmission and gathering pipelines.

For onshore pipelines, PHMSA proposed to allow operators to perform leak surveys without the use of leak detection equipment (i.e., with human senses or animal senses) only for gas transmission and Types A, B, or C gathering pipelines in non-HCA Class 1 and Class 2 locations, and then only with prior notification and review by PHMSA pursuant to § 192.18. Operators would be able to use visual surveys and other survey methods depending exclusively on human or animal senses only if the operator could demonstrate, through tests and analyses outlined in the notification requirements, that the survey method would meet the ALDP performance standard or an approved alternative performance standard proposed at § 192.763(b) or (c), respectively, discussed in further detail in sections III.D and III.E below. PHMSA also proposed to require operators to grade and repair leaks found on gas transmission, offshore gathering, and Types A, B, and C gathering pipelines in accordance with proposed § 192.760. These grading and repair requirements are described further in this document in sections III.H and III.I.

To help ensure timelier detection and repair of leaks that pose a safety hazard, PHMSA proposed to increase the minimum leak survey frequencies for gas transmission and regulated gas gathering pipelines in higher-risk locations based on a pipeline's proximity to occupied buildings and HCAs. For gas transmission, offshore gathering, and Types A, B, and C gathering pipelines located in HCAs, PHMSA proposed increasing the leak survey frequency from once each calendar year to twice each calendar year (at intervals not exceeding 7½ months) if within a

Class 1, Class 2, or Class 3 location; and from once each calendar year to four times each calendar year (at intervals not exceeding 4½ months) for gas transmission and Type A or Type B gathering pipelines located within Class 4 locations within HCAs.

PHMSA also proposed more frequent leak surveys for assemblies such as valve sites, flanges, tie-ins, launchers and receivers, and tanks on gas transmission, offshore gathering, and Types A, B, and C gathering pipelines. PHMSA proposed to require such facilities in Class 1, Class 2, and Class 3 locations be surveyed twice each calendar year (at intervals not exceeding 7 ½ months), compared with once per year under the regulations existing prior to the NPRM. For such facilities in Class 4 locations, PHMSA proposed a survey frequency of at least 4 times each calendar year, at intervals not exceeding 4½ months. In the regulations prior to the NPRM, these facilities in Class 4 locations were subject to an annual survey interval with no recognition of their increased risk to public safety and the environment.

The proposed amendments to the leak survey frequencies for gas transmission pipelines and regulated gas gathering pipelines, compared to the requirements that existed prior to the NPRM, are summarized in the table below.

Summary of Transmission and Regulated Gathering Leak Survey Proposed Amendments

Facility	Pre-NPRM	NPRM
Non-odorized Class 3 transmission	Twice a year not to exceed 7 ½ months.	No change.
Non-odorized Class 4 transmission	Four times a year not to exceed 4 ½ months.	No change.
All other transmission	Once a year not to exceed 15 months.	No change.
HCA Class 1, Class 2, or Class 3 transmission	Once a year not to exceed 15 months.	Twice a year not to exceed 7 ½ months.

HCA Class 4 transmission	Once a year not to exceed 15 months.	Four times a year not to exceed 4 ½ months.
Transmission valves, flanges, pipeline tie-ins with valves and flanges, in-line inspection launcher and in-line inspection receiver facilities, and leak-prone pipe	Once a year not to exceed 15 months.	Same as proposed HCA frequencies.
Regulated gathering	Equivalent to requirements for transmission pipelines for offshore, Type A, Type B, and certain Type C* gathering lines.	Equivalent to requirements for transmission pipelines for all regulated gathering lines.
Notes: If a pipeline segment falls into more than one of these facility types, the most frequent survey applicable would apply. The regulations, prior to the NPRM publishing, stated that operators were only required to use leak detection equipment for surveys on non-odorized pipelines in Class 3 and Class 4 locations. The NPRM proposed that leak detection equipment would always be required for all leak surveys except for surveys operators conducted on pipelines in non-HCA Class 1 and Class 2 locations with a notification to PHMSA and on offshore pipelines below the waterline. *Pre-NPRM Type C pipeline segments that were 16 inches or less in outside diameter that meet the exception criteria using method 1 or method 2 as stipulated by §§ 192.9(f)(1)(i) and 192.9(f)(1)(ii), respectively, were exempt from transmission leak survey requirements in § 192.706 and leak repair requirements in § 192.703.		

PHMSA also proposed changes to the patrolling requirements for gas transmission and regulated gas gathering pipelines. PHMSA regulations previously required operators to annually patrol the rights-of-way on most gas transmission, offshore gathering, and onshore Type A gathering lines. Patrols are visual surveys and do not require the use of any specified equipment. Sections 192.705 and 192.721 define right-of-way patrolling requirements for gas transmission (as well as offshore and Type A gathering) and distribution pipelines, respectively. While offshore and Type A gas gathering pipelines are subject to the same requirements as transmission lines, Type B and Type C gathering pipelines were not subject to any patrolling requirements. In the NPRM, PHMSA proposed to increase the frequency of visual patrols on gas transmission, offshore gathering, and Types A, B, and C gathering pipelines to 12 patrols along the entirety of their pipelines each calendar year, at intervals not exceeding 45 days. This proposal supplanted § 192.705(b), which included a scaled approach of between one and four patrols per year based on the pipeline's class location and the presence of a highway or railroad crossing. PHMSA also proposed to require patrols for Type B and Type C regulated gas gathering pipelines, which is further discussed in Section III.Q.

These proposals applied generally to the pipeline transportation of any "gas," defined in §§ 191.3 and 192.3 as "natural gas, flammable gas, or gas which is toxic or corrosive," including hydrogen, LPG, and other gases.

2. Summary of Public Comments

Patrol Frequency for Gas Transmission Pipelines

Xcel Energy stated that fulfilling the proposed patrol requirements in high alpine areas would be difficult because the window for ground access only lasts for three months out of the year and stated that drone patrols may be limited by wind, visibility, and range.

Multiple commenters including the GPTC, Spire Inc., and GPA Midstream et al., stated that requiring transmission operators to patrol lines monthly would be excessive and onerous, stating PHMSA did not consider class location, terrain, weather, operating pressures, or other relevant factors in determining the survey frequency. The GPTC specifically cited the current "tight labor market," the inability of existing aerial patrol companies to accommodate increased demand, and the fact that PHMSA's analysis did not consider the carbon emissions from increased patrolling. Enstor Gas LLC and York County National Gas Authority echoed that comment insofar as they expressed concerns about the high costs imposed upon operators due to increased labor costs.

Multiple commenters recommended to PHMSA a variety of differing patrol frequencies in lieu of the proposed monthly requirement, including the GPTC suggesting that PHMSA should require a quarterly patrolling frequency and for operators to continue adding preventative and mitigative measures through an operator's IM program. INGAA, Kinder Morgan, Inc., and the Industry Trades recommended PHMSA require the minimum leak patrol interval be 6 times per year at intervals not exceeding 75 days.

Atmos Energy Corporation contended that there is no evidence that increased patrols would promote public safety or protect the environment, with some commenters suggesting PHMSA maintain the existing patrolling requirements located at § 192.705. Multiple commenters, including Enstor LLC, Air Liquide Large Industries U.S. L.P., INGAA, the Industry Trades, Southwest Gas Corporation, and Great Basin Gas Transmission Company, asked PHMSA to consider a risk-based approach for patrolling, where pipelines that are at high risk for leakage be subject to more frequent patrols. The GPTC suggested that for high-risk areas, the patrolling requirements should match the requirements for aboveground inspections of four times per year.

Multiple commenters, including the Joint Environmental comment, supported the more frequent patrol requirements. One commenter supported the survey frequencies proposed in the NPRM and explained that increased patrols would improve community safety, protect the environment, and reduce financial costs from lost gas. The Rocky Mountain Institute's April 2024 comments supported the Committee's recommended patrol frequency of up to six times per year, citing that large emitters make up a greater portion of the total emissions in transmission lines than in distribution lines, which means the quick detection and remediation of these events can prevent significant methane pollution.

The Industry Trades, INGAA, the Arkansas Independent Producers and Royalty Owners, and the Marcellus Shale Coalition expressed concern that PHMSA incorrectly assumed that all operators conduct patrols monthly. The Marcellus Shale Coalition did not provide a suggested patrolling frequency but noted that monthly patrolling did not permit the flexibility to accommodate protected wildlife species. The Industry Trades and INGAA noted that the baseline for transmission patrols was not supported by OMB's Circular A-4 or case law.[222] INGAA further noted that PHMSA had not supported the increased number of patrols and questioned why the existing requirements were "suddenly deficient."[223] Energy Transfer LP stated that PHMSA's assumption that operators conduct monthly patrols in the baseline was

[222] Circular A-4 is a guidance document issued by the Office of Management and Budget to agencies directing them on how to conduct high-quality and evidence-based regulatory analysis. The cases of *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); and *Cape Hatteras Access Pres. All. v. U.S. Dep't of Interior*, 344 F. Supp. 2d 108, 130 (D.D.C. 2004) were cited.

[223] (PHMSA-2021-0039-26287) August 17, 2023. Pp. 12

unreasonable, and in the absence of quantified benefits, the costs of this proposal exceeded its benefits, and PHMSA did not discuss the significance of this projection. The Arkansas Independent Producers and Royalty Owners expressed concerns regarding the patrol frequency, stating that the PRIA failed to contemplate the additional safety risks to personnel, and the benefits from additional patrolling were not monetized. The commenter also disagreed with PHMSA's assumption that Type A gathering pipelines are treated identically to transmission pipelines.

Leak Survey Frequency for Gas Transmission

Multiple commenters, including Enstor Gas LLC, Atmos Energy Corporation, and an individual, voiced general support regarding the proposed gas transmission leak surveys, with multiple commenters similarly supporting the proposed requirement for annual leak surveys for valves, flanges, and facilities outside of HCAs. Gulf Coast Helicopters Inc. supported requiring operators perform more frequent leak survey intervals using less sensitive leak survey equipment that would be simpler and cheaper to use. The Joint Environmental comment suggested survey frequencies that do not vary based on odorization or HCA designation; specifically, they suggested that operators survey pipelines in Class 1, Class 2, and Class 3 locations twice a year, and survey Class 4 pipelines four times per year. Attached to their comment was modeling demonstrating that increasing survey frequency (in combination with leak grading, leak repair timelines, and ALDPs) are critical to identifying leaks that are disproportionally responsible for emissions.[224]

The research cited in the Joint Environmental comment was led by Arvind Ravikumar and Alan Strayer at the University of Texas at Austin, where they evaluated various scenarios that examined the impact of survey frequency using equipment of varying detection thresholds on annual gas release volumes, assuming the respective leaks were then repaired per the proposed PHMSA repair criteria. For this evaluation, the researchers used a modified version of the FEAST[225] (Fugitive Emissions Abatement Simulation Toolkit) code, FEAST-Pipeline, that enabled the code to be applied to gas gathering and gas transmission systems.

Ravikumar and Strayer found that annual gas releases would, in fact, be reduced if gas transmission and gathering systems were surveyed at least as frequently as currently required by § 192.706 and if new repair rules were applied, even if operators used leak detection equipment with a sensitivity significantly less than traditional handheld devices.

As an example, when compared to a baseline scenario using traditional handheld detection methods with a sensitivity of 0.5 kg/hr performed at annual intervals with pre-NPRM repair requirements, gas transmission surveys conducted on annual intervals but with detection equipment having sensitivities of 1, 3, 10, and 30 kg/hr and new repair requirements result in approximately 40- to 50-percent reductions in annual emissions (measured in tons CO_2e/year).[226]

[224] Ravikumar, A.P and Strayer, A., Modeling Leak Detection and Repair Programs for Natural Gas Pipeline Infrastructure Using FEAST, August 2023 (PHMSA-2021-0039-26642).
[225] https://www.eemdl.utexas.edu/feast
[226] Ravikumar, A.P and Strayer, A., Modeling Leak Detection and Repair Programs for Natural Gas Pipeline Infrastructure Using FEAST, August 2023. (PHMSA-2021-0039-26642) Appendix A pp. 46-49

These results indicate that the larger volumes associated with gathering and transmission line leaks enable operators to detect and repair those leaks even by using leak detection equipment with detection sensitivities that are less than traditional handheld devices. Applying new repair requirements to limit the duration that identified leaks can persist is a key aspect of these analyses.

The scenarios that Ravikumar and Strayer examined demonstrated the same trends for gas gathering systems in that using new mobile technologies with detection thresholds between 1 and 30 kg/hr can be applied on an annual basis in conjunction with new repair requirements and result in overall lower annual gas leak emissions.[227] As an example, as compared to a baseline scenario using traditional handheld detection with a sensitivity of 0.5 kg/hr performed at biennial intervals with legacy repair rules, gas gathering surveys conducted with detection equipment having sensitivities of 1, 3, 10 and 30 kg/hr and new repair rules resulted in the reduction of annual emissions (tons CO_2e/year) of approximately 50 percent with little sensitivity to survey frequencies of annual, biannual, or quarterly. These results indicate that the volumes associated with gathering line leaks enable detection and repair even with detection sensitivities that are less than traditional handheld devices. Application of new repair rules that limit the duration that identified leakage can persist is a key aspect of these analyses.

Further supporting this, a comment submitted by Kairos Aerospace, explained that large leaks produce the majority of methane emissions, so frequent leak surveys "that eliminate large

[227] Ravikumar, A.P and Strayer, A., Modeling Leak Detection and Repair Programs for Natural Gas Pipeline Infrastructure Using FEAST, August 2023. (PHMSA-2021-0039-26642) Appendix A. pp. 32-35

leaks quickly reduce more methane than less frequent surveys even with more sensitive instruments."[228] Additionally, surveys using remote sensing equipment are cheaper compared to ground-based surveys as they use less human capital and time.

To buttress their comment, Kairos Aerospace cited an article by Sherwin et al. that is under peer-review at the journal *Nature*. This study includes 1 million aerial measurements and examines 6 basins: the Permian, San Joaquin, Denver-Julesburg, Marcellus, Uinta, and Barnett. The study merged top-down airborne surveys with bottom-up emissions modeling specific to asset inventories and surveyed the area production of each basin in order to develop a full emissions distribution for each basin. Specifically, the study found that "aerially measured emissions at .05 to 1.4 percent of sites contribute to 51 to 81 percent of total emissions in twelve of the fifteen campaigns."[229]

In their comment, Kairos Aerospace also referenced LDAR-SIM, which is a modeling tool that can estimate emissions mitigation and the cost-effectiveness of LDAR programs. Ultimately, Kairos Aerospace found that requiring an annual survey using remote sensing technology with detection sensitivities of 10 kg/hr, 30 kg/hr, and 50 kg/hr would reduce emissions on par with annual surveys using ground-based technology.[230] The commenter showed that increasing the survey frequency from once per year to twice per year would yield almost double the reduction in emissions when using the remote sensing technologies, and they also

[228] (PHMSA-2021-0039-24690). August 16, 2023. Pp.18
[229] PHMSA-2021-0039-24690. August 16, 2023. Pp.9
[230] The ground-based ALDP reduced emissions by 35 percent, whereas the remote sensor of 10 kg/hr reduced by 33 percent, the remote sensor of 30 kg/hr by 33 percent, and the remote sensor of 50 kg/hr by 32%.

noted that a scenario where operators performed surveys once every two months with remote sensing technology with detection sensitivities of 10 kg/hr, 30 kg/hr, and 50 kg/hr had the highest percent of yearly total methane emissions mitigated, with forecasted emission reductions of 91 percent, 88 percent, and 82 percent, respectively.

Some commenters recommended more frequent leak surveys for certain pipeline infrastructure, with the PST suggesting that PHMSA require more frequent leak surveys of valve sites, in-line inspection (ILI) launchers and receivers, and tanks on gathering lines. On the other hand, related to gathering line leak surveys, Physicians for Social Responsibility Pennsylvania, Clean Air Council, a form letter campaign, and an individual commenter opposed providing an exemption for surveying leaks on gathering lines outside of Class 1 and Class 2 locations, with Physicians for Social Responsibility Pennsylvania noting that the location of a pipeline has no impact on the pipeline's ability to emit pollution.

New Jersey Natural Gas and Kinder Morgan, Inc. opposed the proposed quarterly leak survey requirement, with New Jersey Natural Gas expounding that increased leak surveys would require significant revisions to forms and the upgrading and reprogramming of leak management systems. Energy Transfer LP and New Jersey Natural Gas also stated that the proposed survey requirement would require enhanced training and a larger workforce. The North Dakota Petroleum Council noted that more frequent leak surveys would increase operating costs and noted that large leaks are often discovered via pipeline pressure monitoring equipment rather than through ground surveys, especially given that most of the pipelines that their member organizations operate are often underground, and that these large leaks are often minor in nature.

The GPTC noted that increased leak surveys could divert resources from other requirements to monitor and repair leaks and therefore opposed changes to the leak survey frequencies. They additionally suggested there was no conclusive evidence demonstrating that increased surveys would improve safety and recommended PHMSA only require annual leak surveys for transmission lines outside of HCAs. Other commenters suggested alternative survey intervals, with Atmos Energy Corporation suggesting a survey interval of twice per year for pipelines in HCAs in Class 4 locations, and Bridger Photonics recommending that Class 1, Class 2, and Class 3 locations be subject to a leak survey frequency of twice per year.

Washington Gas noted that proposed § 192.706 failed to consider the performance-based benefits of a risk-based model as it applied to leak surveys. Multiple commenters, including the Industry Trades, National Grid, Washington Gas, the GPTC, and Atmos Energy Corporation, requested that, instead of the proposed prescriptive model, PHMSA allow operators to schedule and perform leak surveys based on their IM programs and considering the risk-based preventative and mitigative measures that are required by an operator's gas transmission IM program. National Grid added that PHMSA should not revise the leak survey frequency beyond the current intervals and argued that the proposed additional surveys do not demonstrate a substantial increase in leak detection overall. The April 2024 Industry Trades comment requested PHMSA remove the explicit description of pipelines known to leak based on material "including, cast iron, unprotected steel, wrought iron, and historic plastics with known issues" at proposed § 192.706(d). The commenter cited that this was a list of common natural gas distribution pipeline materials with a propensity to leak and it was out of place given that this part of the regulations is focused on transmission pipelines.

A joint comment written by the Engineers for Healthy Energy and Boston University's School of Public Health asked PHMSA to consider natural gas composition and volatile organic compound content as factors when determining leak survey frequencies. Additionally, the commenters requested PHMSA consider the proximity of nearby populations, residences, and sensitive receptors when determining leak survey frequencies.

Producers Midstream noted that there was no justification for an increase in leak surveys and argued that, due to changes in the ALDP standards, pipelines in Class 1 and Class 2 locations would no longer be able to leverage aerial aircraft to perform surveys, as there would need to be follow-up ground patrols with leak detection equipment. Furthermore, this commenter stated that Class 1 and Class 2 locations are rural and are not densely populated, and pipelines in these locations generally pose little risk to people, property, and the environment.

Comments from the Industry Trades and a February 2024 submission from Alaska Oil and Gas expressed concern about the proposed leak survey frequencies for gas transmission pipelines located in the Alaska North Slope due to cold weather. The Industry Trades argued that pipelines in the Alaska North Slope should be surveyed at least once per calendar year with a maximum interval of 15 months. In their February letter, Alaska Oil and Gas explained that leak detection equipment does not function in the winter, noting specifically the minimum temperature operability for many technologies is -4° Fahrenheit.[231] The commenter also noted

[231] The commenter noted that for about 5 months of the year, the average temperature is below 0° Fahrenheit.

that, while operators maintain a large inventory of spare parts, it is neither practical nor possible for an operator to keep on hand all the parts that may conceivably needed to repair a future leak. They stated that, due to the remoteness of the Alaska North Slope, it may be difficult for operators there to procure parts quickly that are properly rated to endure the harsh temperatures.

Atmos Energy Corporation expressed concern that a single transmission line could be subject to three different leak survey frequencies. Similarly, Southern Company Gas urged PHMSA to remove all references to HCAs from the proposed leak survey frequencies and consider the removal of class locations as a determining criterion for survey frequency, as these could result in complex and conflicting survey requirements for a single pipeline. The commenter argued that class location and HCA classifications are not visible in the field and could increase the chances of unintentional non-compliance, and using HCAs as a designation criterion could result in more HCA mileage being subject to surveying, as operators will need to use Method 1 rather than Method 2 for HCA determination.

Multiple commenters, including Enstor Gas LLC, an individual commenter, and Pennsylvania State Senator Katie Muth, opposed the process PHMSA proposed at § 192.706(a)(2) that an operator would use to be exempt from the requirement to use leak detection equipment in Class 1 and Class 2 locations, as it would be a burden to operators and PHMSA. Specifically, Enstor Gas LLC asked PHMSA to make "a statement that they accept the methodology," which would provide guidance to operators and result in a reduction in correspondence and paperwork.[232] Pennsylvania State Senator Katie Muth added that exemptions do not protect the public from harm.

General Comments

Oleksa and Associates requested that PHMSA provide specific methane emission data and cost data to support an increase in patrols and leak surveys on transmission lines to ensure that the benefits are practicable. The Louisiana (LA) Attorney General et al. was not supportive of the NPRM's proposed requirements for transmission lines; stating that the NPRM failed to satisfy statutory requirements because "the costs outweigh the benefits,"[233] specifically arguing that leaks from offshore pipelines become hydrates or oxidized into carbon dioxide, which likely have a limited impact on the environment, and should thus be exempt from the survey patrol and leak amendments. To further support their argument, they referenced an article by Boles et al. (2023)[234] that found that natural gas production reduces methane seepage in the Santa Barbara channel in California.

In response to PHMSA's request for comments regarding transmission leak survey and patrol frequencies, the Asset Leadership Network stated that the new regulation should be clear on jurisdictional authority regarding private property. The commenter clarified that a customer's service line is private property and is under the jurisdictional authority of the property owner.

[232] (PHMSA-2021-0039-26437) p. 2
[233] (PHMSA-2021-0039-26093) pp. 6-7
[234] Boles, James; Garven, Grant; Peltonen, Chris. "Hydrocarbon production reduces natural methane seeps in the Santa Barbara channel." *Marine and Petroleum Geology.* (2023). Doi.org/10.1016/j.marpetgeo.2023.106187

The New York State Department of Public Service suggested PHMSA consider the role of odorization in an operator's leak management system. Specifically, the commenter recommended PHMSA reconsider odorization exceptions for gas transmission pipelines and consider instituting a performance standard for the odorization of gas pipelines, specifically gas distribution lines, at a level of one-tenth the LEL or below.

3. GPAC Deliberation Summary

On November 28, 2023, the Committee discussion of the NPRM proposals for gas transmission patrols and leak surveys pursuant to §§ 192.705 and 192.706, respectively, began with PHMSA's summary presentation of the proposed regulatory language and its supporting reasoning, including a discussion of its cost and benefits, and an overview of the significant comments from stakeholders on the proposal. After this, members of the public presented their feedback. Among the handful of stakeholders taking this occasion to provide feedback related to the proposals for gas transmission patrols and leak surveys were numerous individuals on behalf of transmission operators, a private citizen, and an individual representing a public interest pipeline safety advocacy organization. Multiple individuals speaking on behalf of the gas transmission industry opposed the proposed monthly patrol frequency with some commenters providing an alternative of either patrolling six times per month or using a risk-based approach. These individuals stated that a monthly patrol schedule was untenable due to various conditions, such as farming activities, snowfall and snow accumulation in locales with challenging topography and terrain, and labor constraints. Multiple operators shared general support for the gas transmission leak survey frequencies as written in the NPRM. The pipeline safety public interest advocate supported the proposed leak survey and patrol frequencies, noting they would increase safety for people and the environment. The private citizen supported transmission operators located in the North Slope being subject to leak surveys[235] twice a year, specifically in May and October, when temperatures are less extreme.

Committee members proceeded to discuss the gas transmission leak survey and patrol frequencies on November 28, 2023. Committee members representing the industry generally agreed that patrolling is not an effective method for identifying leaks and cited concern about the associated emissions with performing more frequent patrols. A GPAC member representing NAPSR proposed a quarterly leak patrol frequency and added that the purpose of patrolling is to prevent the threat of future leaks and identify seasonal variation in the area surrounding piping. A GPAC member representing the industry echoed some of the public comments and proposed patrolling 6 times per year in high-risk areas and quarterly in low-risk areas. Committee members representing industry, government, and the public supported allowing operators to perform risk analysis to determine patrol frequency. While ultimately not provided as a recommendation, Committee members representing the public and industry expressed interest in PHMSA conducting a study to evaluate the effectiveness and value in patrolling. A GPAC member representing the public suggested that operator reporting regarding patrolling would allow for a better assessment of its value. There was a short discussion regarding gas transmission leak survey frequencies, because GPAC members representing both industry and

[235] The commenter used the term "leak detection." Based on the commenter's reference to advanced leak detection, it was interpreted that this individual's comment concerned gas transmission leak survey frequencies.

the public repeated the sentiments shared by many public commenters expressing support for § 192.706 as proposed. A GPAC member representing the public highlighted written comments that supported greater leak survey frequencies.

4. GPAC Recommendation

The Committee unanimously supported the proposals on leak survey frequency at § 192.706 as written in the NPRM. In a separate vote, the Committee unanimously agreed the proposed gas transmission patrol requirements at § 192.705 were technically feasible, reasonable, cost-effective, and practicable if PHMSA made the following changes:

- Operators patrol Class 3 and Class 4 locations 6 times each calendar year at intervals not exceeding 75 days, and operators patrol Class 1 and Class 2 locations 4 times each calendar year.
- Further discuss gas transmission patrol-related reporting during the broader discussion of reporting in agenda item 6 of the GPAC meeting.

While themes of operator flexibility, practicability, and ensuring a commensurate safety benefit with the cost of additional patrols arose, the GPAC discussion primarily centered around the ideas of the value of patrolling and developing a risk-based approach. While the Committee did not adopt a recommendation for PHMSA to prepare specific reports concerning patrolling or conduct a study about the effectiveness of patrolling, the recommendation to discuss reporting in the context of patrols was born out of the desire to better understand the benefit of patrolling.

5. PHMSA Response

Section IV.A of the NPRM explained that the proposals would both satisfy the terms of its section 113 mandate and reinforce the self-executing mandate in section 114 of the PIPES Act of 2020 and PHMSA's exercise of its public safety and environmental safety authority at 49 U.S.C. 60102(a) through (b), and would yield significant public safety and environmental benefits. Type C gas gathering pipelines with an outside diameter of 16 inches or less, which comprise the majority of Type C gathering lines, are not currently subject to any leak survey or repair requirements at all unless they are located near buildings intended for human occupancy or other impacted site (*see* § 192.9(f)). In addition, operators of gas transmission and regulated gathering pipelines subject to leak survey requirements are not obliged to use leak detection equipment in performing those surveys unless they are non-odorized lines located in Class 3 or Class 4 locations. And for operators of the non-odorized mileage of gas transmission and regulated gathering pipelines in Class 3 and Class 4 locations that were, prior to this rulemaking, required to perform leak surveys using leak detection equipment, the silence in the regulations regarding the required minimum performance of that equipment resulted in a lack of an enforceable requirement to use commercially available advanced leak detection equipment in detecting leaks during leak surveys. Meanwhile, the leak survey frequencies that existed prior to this rulemaking, the NPRM explained, were so long that even Grade 1 leaks that were public safety and environmental hazards could remain undetected until the next survey. The prolonged time intervals between leak surveys increased public and environmental risks from the delay in detecting even small leaks from gas transmission and regulated gathering lines, as such delays can prolong the accumulation of combustible methane, allow the continued degradation of a leak before repair, contribute to climate change, and, for gas gathering lines, result in larger releases of toxic constituents such as HAPs and VOCs. Nor, moreover, did IM requirements at subpart O adequately address these concerns, as only a limited amount of gas transmission mileage and no gas gathering pipelines are subject to the IM requirements. The NPRM also explained that PHMSA's IM regulations and guidance afford operators broad discretion in determining the manner and frequency of leak surveys conducted beyond the minimal, baseline prescriptive requirements in § 192.706, thereby potentially inhibiting effective regulatory backstopping of operator practices. Indeed, gas transmission operators reported 62 incidents attributed to leaks from 2010 through 2023 in HCAs subject to IM requirements. Lastly, the NPRM explained that infrequent, or, for Types B and C gas gathering lines, inapplicable patrol requirements forego any synergies with leak survey requirements in identifying leaks and also prolong periods before operators identify emerging integrity threats or changed class locations, which, in turn, informs the number of leak surveys required under PHMSA regulation and the scope of part 192 regulations for regulated onshore gas gathering lines.

The FEAST modeling data discussed at the 2021 EPA Methane Leak Detection Technology Workshop strongly supported the intuitive relationship between leak detection efficacy and leak survey frequency.[236] Considering operators' limited resources, PHMSA chose

[236] 88 FR 31890 at p. 31926. PHMSA further notes that leakage surveys have been the principal regulatory approach for identifying leaks and anomalies on pipelines since the inception of the Pipeline Safety Laws in the late 1960s. See Hazardous Materials Regulation Board, "Final Rule: Transportation of Natural and Other Gas by Pipeline: Minimum Standards" 35 FR 13248 (Aug. 19, 1970).

to focus the NPRM's proposals on improving leak survey technology and practices on gas transmission and regulated gathering pipelines where those enhancements would yield the greatest reductions in risks to public safety and the environment. Specifically, the NPRM proposed a default requirement that operators would perform all leak surveys under § 192.706 using leak detection equipment compliant with the performance standards at § 192.763 to help ensure leak surveys were performed using equipment with minimum sensitivity levels corresponding to those of commercially available, advanced technology. In contrast, PHMSA determined that leak surveys on pipelines in circumstances where visual means of leak surveys have proven effective for identifying leaks, or where the location of the pipeline meant it posed relatively low risk to public safety, warranted less demanding technology requirements. The NPRM, therefore, proposed operators of sub-waterline offshore gas transmission and gathering pipelines and onshore gas transmission and gathering pipelines in less densely populated Class 1 or Class 2 locations outside of HCAs would not be required to use leak detection equipment for leak surveys or could request an alternative ALDP performance standard in § 192.763 after notification to PHMSA pursuant to § 192.18.

The NPRM similarly calibrated implementation burdens against avoided public safety and environmental risks when proposing increased survey frequencies for gas transmission and regulated onshore gas gathering pipelines based on proximity to occupied buildings as determined by class location within an HCA. Specifically, the NPRM proposed that operators of gas transmission pipelines in HCAs in Class 1, Class 2, and Class 3 locations would perform leak surveys on the same semi-annual frequency required, pre-NPRM, for non-odorized lines in Class

3 locations. Operators of gas transmission pipelines in Class 4 locations within HCAs would perform leak surveys on the same quarterly basis as required, pre-NPRM, for non-odorized transmission lines in Class 4 locations.

Outside of HCAs, PHMSA also proposed enhanced leak survey frequencies for gas transmission and regulated gathering equipment and facilities that are particularly susceptible to leakage, including certain components, such as valves and flanges, with greater propensity to leak, as well as pipelines known to leak based on material, design, or operating history. Specifically, the NPRM proposed semi-annual surveys for pipelines located in Class 1, Class 2, and Class 3 locations, but quarterly surveys for pipelines in more densely populated Class 4 locations. PHMSA proposed to extend this requirement to all Type C gathering lines, eliminating the prior exception from such requirements for certain Type C lines with an outside diameter of 16 inches or less in § 192.9(f). PHMSA previously determined that, due to their physical and operating characteristics, Type C gathering pipelines pose public safety and environmental risks similar to those of gas transmission lines. However, as described in greater detail in sections II.B.3 and III.P, with respect to the frequency of leaks and volume of emissions, the public safety and environmental risks of gas gathering lines, including Type C gathering lines, exceeds those of gas transmission lines; PHMSA explained in the NPRM that leaks from all Type C lines, including those with a diameter of 16 inches or less, regardless of location, were significant emissions sources.[237] Lastly, PHMSA also proposed monthly patrol requirements for all gas transmission and onshore regulated gathering pipelines, including, for the first time, Types B and

[237] 88 FR 31890 at p. 31931 (May 18, 2023).

C gas gathering pipelines, to allow for more timely identification of emerging integrity threats or changed class locations and better align the regulations with PHMSA's understanding of current operator practices regarding right-of-way surveys. Therefore, the NPRM's risk-informed enhancements to gas transmission and regulated gathering leak survey and patrolling requirements, considered alongside the leak detection equipment and ALDP performance standards provided for elsewhere in the rulemaking, would improve the efficacy of leak surveys, thereby helping ensure the timely and effective identification and repair of such leaks on pipelines in a way that significantly reduces public safety and environmental harms.

The administrative record developed in response to the NPRM, summarized above at sections III.B.2 to B.4, and below at sections III.P.2 to P.4 within this document, highlighted stakeholder concerns with PHMSA's proposed approach. First, industry stakeholders and their trade associations who submitted comments on the NPRM and participated in GPAC discussions generally criticized PHMSA's proposal as offering inadequate public safety and environmental benefit at greatly increased cost. Industry stakeholders and their trade associations, moreover, warned that those increased compliance costs could in fact prove zero-sum with other measures—for example, IM compliance efforts—they characterized as more effective in protecting public safety and the environment than PHMSA's proposed enhanced leak detection survey and patrol requirements. Second, several stakeholders, generally representing the industry, submitted comments on, and raised during the GPAC discussions, implementation concerns arising from allegedly unclear or overbroad proposed regulatory language (e.g., the content of "pipelines known to leak") that could increase the leak survey frequencies for some gas transmission and regulated gas gathering pipelines. Third, industry stakeholders also highlighted the potentially high costs and practical limitations on requiring them to conduct monthly patrols on all pipelines because of the difficulty in conducting those patrols over diverse terrains and harsh operating conditions (e.g., weather and climate) and the alleged limited value for patrols to identify leaks. As explained in sections III.B.3 and B.4 above and sections III.P.3 and P.4 below within this document, the GPAC discussed those industry stakeholder concerns, resulting in a unanimous recommendation endorsing the NPRM's proposed enhanced frequencies and equipment requirements for leak surveys on gas transmission and Types A and B gathering lines. For Type C gas gathering pipelines, which are all located in Class 1 areas, the GPAC unanimously endorsed annual leak surveys for larger lines (those that are greater than 16 inches in outside diameter) as well as for smaller lines (16 inches or less in outside diameter) near occupied buildings, alluding to the scope of the exceptions in § 192.9(f) for certain requirements for Type C gathering lines with an outside diameter of less than or equal to 16 inches that are not located within a potential impact circle (or alternatively, a class location unit) containing a building intended for human occupancy or other impacted site. As described in section III.P.3, Committee members representing the industry conceded that larger-diameter gathering lines more closely resembled transmission lines with respect to their physical layout, conduciveness to aerial leak surveys, and maturity of leak survey compliance programs, and should therefore be incorporated into the transmission line aerial survey program.

For certain Type C gathering lines with a diameter of 16 inches or less,[238] the GPAC recommended that operators of these other Type C gas gathering lines should only perform leak surveys once every 5 years. Again, as described in section III.P.3, members representing operators presented maps showing that smaller-diameter lines were generally web-like systems connecting individual production operations to the broader gathering systems compared to larger-diameter, linear trunk lines. These members described concerns with the short-term efficiency and practicability of implementing frequent aerial surveys of such complex facilities until operators could develop cooperative survey agreements, develop satellite technologies, and gain experience with LDAR compliance programs. For Type C gathering lines subject to a 5-year survey frequency, the GPAC also recommended an initial, one-time survey for those lines on or around the compliance date of any final rule in this rulemaking proceeding.

Lastly, the GPAC unanimously recommended more frequent gas transmission patrols than pre-NPRM regulations as a function of public safety risk; specifically, the GPAC recommended bi-monthly surveys in Class 3 and Class 4 locations, and quarterly surveys in Class 1 and Class 2 locations.

Based on its review of that administrative record, including section IV.A of the NPRM, which analysis is hereby incorporated in this final rule, PHMSA has adopted in this final rule many of the NPRM's proposals related to leak surveys. Specifically, this final rule adopts the

[238] The text of the GPAC recommendation applies the more frequent survey interval to Type C pipelines with an outside diameter of 16 inches or greater. However, PHMSA infers that the GPAC's intent was to map the bifurcated survey requirements with the scope of § 192.9(f), which applies enhanced requirements for pipelines greater than 16 inches in diameter and smaller lines located near buildings, rather than create a third category of Type C gathering line.

NPRM's, GPAC-endorsed, proposals for enhanced, identical leak survey equipment and frequency requirements for gas transmission and Types A and B gathering lines in light of the public safety risks associated with leaks from those lines that can involve relatively large throughput capacity and proximity to occupied buildings[239]—considerations also pertinent to the environmental risks posed by leaks from those lines. This final rule therefore continues the historical congruence in PHMSA regulation between leak survey equipment and frequency requirements for gas transmission and Types A and B gas gathering lines in part because those pipelines are subject to similar integrity threats (corrosion, external forces, etc.) that can create or exacerbate leaks. This final rule also adopts PHMSA's proposed, GPAC-endorsed, risk-informed calibration of leak survey frequencies for gas transmission lines in HCAs. By definition, a pipeline in an HCA is located in an area with elevated risks to public safety based on proximity to occupied buildings. Most HCAs are identified under method 2 in § 192.903 which defines an HCAs based on the presence of 20 or more buildings intended for human occupancy or one or more identified site (places where people congregate) within the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. Any leak that results in a fire or explosion in these highly populated areas could therefore result in serious public safety and environmental consequences. PHMSA's review of gas transmission incident report data yields that gas transmission lines traversing HCAs merit more frequent leak surveys

[239] PHMSA, "Final Rule: Gas Gathering Line Definition; Alternative Definition for Onshore Lines and New Safety Standards" 71 FR 13289 at p. 13291 (Mar. 15, 2006). That said, these gathering lines had been subject to the same leakage survey requirements since the introduction in 1975 of § 192.706 in 1975. See U.S. DOT Office of Pipeline Safety, "NPRM: Definition of Gathering Line" 39 FR 34569 (Sept. 26, 1974).

than other transmission lines; despite efforts to prevent failures under IM requirements, approximately 9 percent of gas transmission incidents, including 10 percent of incidents reported as leaks, occur on gas transmission lines in HCAs. More frequent leak surveys can help ensure that such events and other leaks are detected, responded to, and repaired more rapidly, reducing the risk to public safety, property, and the environment. This final rule also adopts the NPRM's, GPAC-endorsed, proposals for enhanced leak survey frequency on lines or components that are relatively more susceptible to leaks. Unlike line pipe, which is a continuous length of tubing that will only leak when the pipe body, welds, or fusion points have physically failed, valves, flanges, and other components and assemblies are more complicated in configuration because they include substantially more seals, connections, and moving parts that represent potential interfaces for leakage. For example, failure on any point on a flanged connection can result in leakage, including the gasket, bolts, and the flanges themselves. Similarly, valves can leak through the valve body, through the packing at the valve stem, at flanged connections, or through the valve itself in the case of relief valves and other valves open to the atmosphere. Indeed, statements by GPAC members representing gas transmission operators and PHMSA incident data confirms that non-pipe components, particularly various types of valves, on gas transmission and regulated gas gathering lines, experience a significant share of incidents compared with line pipe, despite the fact that the latter represents the vast majority of mileage on a typical gas transmission system. Between 2010 and 2023, components other than pipe and welds were the cause of 889 out of 1,723 incidents on gas transmission and regulated gas gathering lines. Among those, "valves" was the single most common cause of failure at 316, followed by "other" at 147, "regulator/control valve" at 80, and compressor station emergency shutdown systems (essentially a blowdown valve assembly) at 79. These results could understate the rate of failure of non-pipe components, since pipe failures are probably more likely to result in reportable consequences due to their location outside of operator-controlled property, higher cost of repair, and risk of rupture. The leakage rate of valves and other components and assemblies is further demonstrated by the conclusions of the U.S. GHGI prepared by the EPA and summarized in II.B.3, which observes that in the transmission and storage sector, fugitive emissions from more complex facilities such as compressor stations and meter and regulator stations eclipses emissions associated with leaks from gas transmission line pipe. PHMSA incident data similarly reveals that gas transmission and Types A and B gas gathering lines composed of materials or fabrication methods that are known to leak or rupture experience leaks resulting in incidents more frequently than protected steel segments of the same lines. For example, despite the fact that 97 percent of transmission and regulated gas gathering mileage is coated and cathodically protected, 6 percent of external corrosion incidents occurred on pipelines that were not cathodically protected. Any other gas transmission and Type A and Type B gathering lines would, as PHMSA had proposed in the NPRM, remain subject to the default annual leak survey requirement existing prior to this rulemaking.

This final rule elsewhere adjusts the NPRM's leak survey and ALDP proposals consistent with GPAC recommendations to achieve significant emissions reductions from gas transmission and regulated gas gathering lines with reduced compliance costs. As explained in section III.D, this final rule reduces the cost of each survey compared to the NPRM by adjusting performance standards to allow the use of less-sensitive leak screening survey equipment consistent with the performance of cost-effective aerial survey and continuous monitoring techniques. And although this final rule, like the NPRM, introduces leak survey requirements for Type C gas gathering lines, it reduces the frequency of those leak surveys compared to the NPRM based on a consideration of public safety and environmental risks of those largely rural lines, as well as implementation challenges those lines may face in the short term. As stated above, leaks from any Type C gathering line pose public safety and environmental risks comparable to leaks on gas transmission lines with similar design and operational characteristics and in similar locations because of the similar throughout capacities involved as well as the presence of toxic, corrosive, and other hazardous constituents in unprocessed natural gas, which can also accelerate leak degradation. However, as discussed extensively in comments on the NPRM and during the GPAC discussions, most Type C gathering lines have only recently come under PHMSA safety regulations and may not be operated by operators with extensive experience in LDAR compliance programs—meaning that many operators may be struggling to come into compliance with existing PHMSA regulations, much less the entirety of the additional requirements in this final rule. Requirements for leak surveys at the same cadence as gas transmission and Types A and B gas gathering lines then, would exacerbate the compliance burdens on those operators, many of whom, as noted in written comments on the NPRM and GPAC discussion, indicate they may have limited understanding of the precise location of their lines to perform leak surveys due to the web-like configuration of many gathering systems (particularly for smaller Type C lines currently excepted from leak survey requirements), historically poor recordkeeping, and limited historical State and Federal regulatory oversight.

In acknowledgment of these practical limitations, PHMSA in this final rule is revising its NPRM proposals to adopt distinguishable leak survey frequencies for different Type C gas gathering lines based on the ease of aerial surveillance and, for smaller diameter lines, public safety and environmental risks. As discussed above and in section III.P, the significant quantified environmental benefits from leak detection and repair requirements for regulated gas gathering lines are not dependent on proximity to structures. Further, as certain Type C gathering lines were previously exempted from requirements to "promptly repair hazardous leaks," this represented a serious gap in public and environmental safety. Therefore, PHMSA did not adopt alternatives proposed by commenters for Type C gathering lines, such as excepting smaller-diameter pipelines located away from buildings, from the leakage survey, patrol, and ALDP requirements of this final rule.

Specifically, this final rule adopts the GPAC's recommended survey frequency for Type C gathering lines. In this final rule, Type C gathering lines currently required to comply with leakage survey requirements will continue applying the existing annual leakage survey frequency. These represent Type C gas gathering lines with nominal diameters greater than 16 inches, and smaller Type C gas gathering lines between 8.625 and 16 inches in outside diameter located within a potential impact circle containing occupied buildings. As noted in the GPAC discussion, Type C gathering lines larger than 16 inches in outside diameter tend to be, similar to transmission lines, linear and relatively easier to survey with aerial technology. While gathering lines between 8.625 and 16 inches located within a potential impact circle containing a building intended for human occupancy or other impacted site may be more challenging to survey, the potential for direct impacts to public safety justify retaining the existing, annual survey frequency.

Conversely, other Type C gas gathering pipelines that are between 8 and 16 inches in outside diameter and not near occupied buildings are more challenging to survey in the short term and may entail comparatively less significant public safety and environmental risks. Additionally, these facilities were previously excepted from leak survey and leak repair requirements under § 192.9(f). For these lines, PHMSA adopts the GPAC's recommendation by providing for a uniform 5-year frequency for leak surveys for these pipelines, with such surveys being performed while the pipelines are in operation to address concerns regarding potential intermittency of leak indications. PHMSA considered incorporating the GPAC's recommendation to require an initial baseline leak survey occur on or before the compliance date of January 1, 2028, for Type C gathering lines that would be subject to a 5-year recurring survey frequency. However, the final rule does not adopt this baseline survey requirement in light of extensive administrative record evidence indicating operators of smaller diameter Type C gathering lines have a poor understanding of the precise location of those lines and that performing aerial surveys of their entire system in a short period of time may be challenging for some operators.[240] This final rule's leak survey frequencies for Type C gas gathering lines,

[240] Experience obtained in implementing this final rule may inform future rulemakings that could adopt more frequent default leakage survey requirements for Type C gas gathering lines. And even in the absence of an

therefore, reflects PHMSA's balancing of anticipated public safety and environmental benefits against near-term implementation challenges specific to Type C gas gathering operators.

These changes significantly reduce compliance costs compared to the NPRM but also proportionately reduce environmental and safety benefits and result in lower net benefits. However, PHMSA is persuaded that these changes are necessary to help ensure that the implementation of survey requirements is practicable for smaller-diameter Type C gathering lines. As discussed above, during the March 2024 GPAC meeting, a member representing an operator of gas transmission and regulated gas gathering lines presented maps of various gas gathering systems and discussed the potential challenges of surveying smaller-diameter lines.[241] In particular, Committee members representing the industry referenced that, in the medium- to long-term, they would need to work on cooperative agreements to perform surveys among operators of gathering lines in the same location or wait for improved aerial and satellite technologies to ensure that leakage surveys of these smaller-diameter facilities can be performed efficiently. Aerial leakage survey technologies and pipeline repair methodologies used on gathering lines are unlikely to differ in ways that would lead to increased costs for gathering lines compared with transmission lines that are subject to more regulatory requirements, may

explicit regulatory requirement for more frequent leakage surveys, reasonably prudent operators may—either as mandated by applicable state requirements or in response to commercial prerogatives—seek to compile, generate, and transfer into an accessible format any legacy records for their systems to protect public safety and the environment from the pressurized (natural flammable, corrosive, or toxic) gases transported in their pipelines. PHMSA applauds those operators who have already proactively invested in those efforts or will do so following issuance of this final rule.

[241] GPAC Transcript beginning at 29 (Mar. 25, 2024). Example maps referenced in the remarks are available in the docket (PHMSA-2024-0005).

operate at higher pressure, and that may have reliability constraints. However, this change addresses an important way that the design of a gathering system may differ from typical transmission systems in a way that affects the efficiency of performing aerial leakage surveys.

Performing aerial surveys of more complex pipeline networks are still feasible by flying a grid or other search pattern, and while smaller-diameter Type C gathering may be less linear than a typical gas transmission line, distribution systems have similarly complex layouts and are routinely surveyed, as often as annually, using leak detection equipment. Nevertheless, PHMSA recognizes that it may take time for recently regulated Type C gathering line operators to establish effective and efficient leak detection programs and agrees that, in the interim, a longer survey frequency is justified. Because of the significant potential environmental benefits of a more frequent survey frequency of gas gathering lines PHMSA expects to reconsider the survey frequency it finalized in this rulemaking in the future as leak detection technology and practices improve and operators gain additional experience performing leakage surveys of more complex systems.

This final rule's enhanced leak survey equipment and frequency requirements will result in improved leak identification and reductions in public safety and environmental risks. This final rule's enhanced survey frequencies for these gas transmission and regulated gathering lines are supported by materials introduced in the administrative record by stakeholders—including the GPAC discussion, peer-reviewed studies,[242] FEAST modeling data for gas transmission and

[242] Yu et al., "Methane Emissions from Natural Gas Gathering Pipelines in the Permian Basin," 9 Environ. Sci. Technol. Lett. Pg. 969 (Nov. 8, 2022); Cusworth, Daniel et al. "Strong Methane Point Sources Contribute a

regulated gathering pipelines performed for the EDF,[243] and LDAR-Sim modeling results performed by Highwood Emissions on behalf of the API[244] and separately by Kairos Aerospace using data for leaks on gas gathering lines in several production basins[245]—corroborating the NPRM's conclusion that leak identification efficacy and total program emissions reductions are generally correlated to survey frequency. Those materials also underscore that increased leak survey frequencies can be an important contributor to leak identification efficacy since more frequent leak surveys provide additional opportunities for operators to identify leaks missed in earlier surveys or that have degraded above minimum leak detection equipment sensitivity levels since an earlier survey. Evidence in the administrative record submitted by stakeholders also underscores the emissions benefits of increased leak detection efficacy for gas transmission and regulated gathering lines. Because leaks from those facilities generally involve larger release rates than those typical of lower-pressure distribution lines, increased leak survey frequencies and improved leak detection technologies will identify the leaks responsible for most emissions from those lines, and earlier identification and repair of those leaks will reduce the total duration, and therefore volume, of a release.[246] And although this final rule adopts less-frequent leak

Disproportionate Fraction of Total Emissions Across Multiple Basins in the United States." 119 PNAS, No 38, (September 13, 2022).

[243] EDF FEAST Modeling Slide deck at 26, 41. PHMSA-2021-0039-26642.

[244] Highwood Emissions Management. PHMSA-2021-0039-26370.

[245] Kairos Aerospace at 8, 18. (PHMSA-2021-0039-24690).

[246] This logic holds true for Type B gas gathering lines as well as other regulated gathering lines. Although by definition Type B gas gathering lines operate at lower pressures than Types A and C gathering lines, Type B lines can nevertheless have operating pressures high enough above atmospheric pressure that any leaks would result in high release rates. Further, to the extent that the relatively lower operating pressures of Type B gas gathering lines make it less likely that a leak would result in a catastrophic (and potentially more obvious) rupture than a leak on

survey requirements for Type C gas gathering lines than had been proposed in the NPRM, PHMSA expects the frequencies being finalized here will yield significantly improved leak detection efficacy and emissions reductions benefits compared to PHMSA regulations prior to this rulemaking. First, as noted above, PHMSA regulations existing before this rulemaking only required operators of certain Type C gathering lines to perform leak surveys, such that even the 5-year leak survey frequency for Type C gathering lines previously excepted under § 192.9(f) adopted in this final rule is a significant improvement. Second, even as operators would not be required to conduct leak surveys more frequently than specified in this final rule, they would not be able to ignore leaks brought to their attention by third parties or their own personnel and contractors (e.g., during more frequent patrols required by this final rule); pursuant to § 192.703(c), such leaks would need to be graded and repaired consistent with an operator's § 192.763-compliant ALDP, as well as incorporated within data in the operator's annual report to PHMSA.

Lastly, PHMSA's review of the administrative record (including section IV.A of the NPRM) supports its adoption of enhanced right-of-way patrol requirements for gas transmission and regulated gathering lines—even as it is not adopting the same patrol frequencies it had proposed in the NPRM. Although industry representatives in written comments and the GPAC discussions questioned the value of enhanced patrol requirements for leak detection efforts, PHMSA has long considered leak surveys and patrol requirements to be complementary

a higher-pressure Type A or C gathering line, PHMSA concludes that phenomenon underscores the value for timely identification of leaks of increased leakage surveys for Type B gas gathering lines.

practices for identifying pipeline integrity failures and threats. Indeed, since the introduction of the PSR in 1970, the regulatory text of § 192.705(a) has explicitly acknowledged the value of patrols for identifying surface expressions of leaks from gas pipelines.[247] That historical understanding, moreover, is consistent with gas transmission and regulated gas gathering incident data: 11 percent of incidents reported as leaks on gas transmission and regulated gathering lines between 2010 and 2023 were initially identified by air or ground patrols. And although patrols may not be as sensitive as leak survey screening or handheld leak detection technologies, they can nevertheless be an effective tool for identifying leaks large enough to result in noteworthy surface expressions (e.g., dead vegetation or soil disturbance).

This final rule adjusts the NPRM's monthly leak survey proposals consistent with GPAC recommendations to reduce compliance costs and better align with the public safety risks of different pipelines. Relative to the regulations prior to this rulemaking, this final rule prescribes enhanced patrol frequencies for gas transmission and Type A gathering pipelines that pose greater risks to public safety as indicated by their class location: bi-monthly patrols for pipelines in Class 3 and Class 4 locations, and quarterly patrols (the same frequency previously required for Class 4 pipelines) for pipelines in Class 1 and Class 2 locations. Types B and C gas gathering pipelines must, for the first time, perform right-of-way patrols; this final rule requires annual patrols for those lines. As explained above, PHMSA has long considered leak surveys and patrols to be complementary approaches within an operator's leak management practices; this is

[247] See Hazardous Materials Regulation Board, "Final Rule: Pipeline Safety Regulations," 35 FR 13248 at p. 13273 (Aug. 19, 1970).

particularly the case when patrols are performed between required leak surveys. PHMSA incident data also demonstrates that patrols are a highly effective tool for the timely identification of in-progress leaks so serious as to meet the regulatory definition of an incident; PHMSA therefore expects this final rule's substantially increased patrol frequencies—and introduction of a patrol requirement for Types B and C gathering lines[248]—will accelerate the identification of those leaks on gas transmission and regulated gathering lines, thereby minimizing public safety and environmental harms. Similarly, more frequent patrols can help operators promptly identify development and construction activity meriting more frequent leak surveys under PHMSA regulations that can in turn identify leaks for repair or monitoring. More frequent patrols also have preventative value by providing additional opportunities for operators to identify pipeline integrity threats before they cause a leak.

For the reasons described above and coupled with mutually reinforcing provisions being established through this rule, PHMSA expects the risk-based refinements it is making to this final rule's leak survey and patrol requirements for gas transmission and regulated gathering pipelines will yield significant improvements compared to the status quo and the NPRM alike in the timely, cost-effective identification and repair of leaks entailing the greatest public safety and environmental risks.

[248] Annual patrols will be a particularly important mechanism for identifying or preventing leaks on gas gathering lines given that the poor records of many Type C operators regarding the location of their pipelines may inhibit effective leakage surveys. Visual patrols may be able to reveal the precise location of a leaking gas gathering pipeline within a web-like gas gathering system in a way that leakage screening surveys may not without further investigation. Additionally, annual patrols will provide Type C gathering lines with relatively-infrequent, 5-year leakage surveys additional opportunities to identify and repair leaks on their systems.

Patrol Frequency for Gas Transmission

PHMSA is adopting the Committee's recommendations with respect to the frequency of patrols on gas transmission pipelines at § 192.705; accordingly, in this final rule, PHMSA requires operators to perform patrols 4 times per calendar year, at intervals not exceeding 135 days, on pipelines in Class 1 and Class 2 locations, and 6 times each calendar year, at intervals not exceeding 75 days, on pipelines in Class 3 and Class 4 locations. The revised patrol frequency adopted in this final rule reduces costs compared to the proposed monthly patrol frequency while still being more frequent than what the regulations prior to this rulemaking required. The increased patrol frequency increases the likelihood that an operator will identify visually identifiable integrity threats, such as excavation activity or earth movement before it results in a leak or incident. If such a threat has already occurred, it provides the opportunity for an operator to determine if damage to the pipeline has occurred.

In its recommendation, the Committee stipulated that, for pipelines in Class 3 and Class 4 locations, the patrolling intervals should not exceed 75 days. However, for pipelines in Class 1 and Class 2 locations, the Committee did not provide a maximum patrolling interval. PHMSA did not interpret the Committee's exclusion of a maximum patrolling interval for pipelines in Class 1 and Class 2 locations to suggest an explicit recommendation against PHMSA establishing one. Therefore, consistent with other activities required on a quarterly basis in part 192, including existing patrol requirements at § 192.705(b), PHMSA is requiring in this final rule that the interval for patrolling pipelines in Class 1 and Class 2 locations may not exceed 135 days, which aligns with the currently permitted maximum interval between patrols for pipelines at highway and railroad crossings in Class 1 and Class 2 locations. This interval will allow operators with gas transmission pipelines in Class 1 and Class 2 locations more flexibility when scheduling their patrols.

Additionally, the RIA demonstrates that patrolling addresses known threats to pipeline integrity, such as third-party damage and natural force damage, which can be very costly. From 2014 to 2023, there were 85 incidents caused by natural force damage, which accounted for approximately 8 percent of incidents. During this same 10-year period, there were 130 incidents attributed to excavation damage, which accounted for approximately 12 percent of incidents. Furthermore, there were 5 fatalities and 17 injuries associated with these excavation damage incidents. These incidents collectively amounted to over $190 million in costs to operators over that 10-year period.[249]

In response to multiple commenters' concerns about patrol frequency, the risk-based, class location-based patrol frequency in this final rule is supported by the Committee's recommendation and targets patrol efforts towards the highest risk locations, which significantly reduces the compliance costs associated with this requirement compared with the proposed monthly frequency. As described in section III.P, the final rule adopts a monthly patrol requirement for Type B and Type C gathering lines, which again significantly reduces compliance costs for operators that are likely to have lower baseline compliance but helps ensure that operators of all regulated gas gathering lines periodically assess the condition of their

[249] U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration's Data Portal from March 11, 2024. See docket for webpage. Portal.phmsa.dot.gov

pipeline right-of-way. The final RIA and this rulemaking are responsive to these comments, as the latter stipulates varying patrol frequencies based on class location, recognizing certain pipelines pose a lower risk and would not benefit from more frequent patrolling. This final rule sets a minimum frequency; operators may add more preventative and mitigative measures, including additional patrols, to their IM programs. PHMSA encourages operators to do so in addition to complying with the requirements in § 192.705, should they find this to be effective.

Hazardous liquid operators, in accordance with § 195.412(a) and regardless of the pipeline's location, elevation, or climate, conduct patrols 26 times per year at intervals not exceeding 3 weeks, which demonstrates that it is practicable for operators to perform frequent patrols. Nevertheless, in the interest of reducing the cost burden to operators, this final rule does not implement such a frequent patrol interval. Additionally, the decreased patrol frequency provides more flexibility for operators to schedule patrols around conditions that may prevent a successful patrol, such as weather conditions affecting aerial patrols. Furthermore, there are alternatives to ground patrols, such as patrols with unmanned aerial systems (UAS) and traditional aircraft, that operators may use to comply with § 192.705 when ground access to facilities is difficult or unnecessary. In comparison to the proposal, which stipulated a monthly patrol interval, this final rule provides operators either a bi-monthly or quarterly patrol frequency depending on a pipeline's class location, which helps alleviate commenter concerns about temporary restrictions on access. Most transmission pipelines, by mileage, are in Class 1 and Class 2 locations, which, in accordance with this final rule, are subject to a quarterly patrol interval.

PHMSA acknowledges operator concerns with the costs, impacts, and operational challenges with requiring patrols at the frequencies PHMSA proposed in the NPRM. Compared with the monthly patrol frequency proposed in the NPRM, the risk-based patrol frequency in the final rule significantly reduces the number of pilots or other personnel required across the gas transmission and gathering line industry to perform patrols and gives operators more flexibility to schedule around weather conditions and other obstacles to performing patrols. To the point that PHMSA did not account for the additional emissions that additional patrols would cause, PHMSA revised the RIA to account for carbon emissions in patrols and encourages readers to review the RIA for a more detailed discussion. In response to concerns about conducting patrols in locations with extreme weather or difficult terrain, many if not all of these locations would be categorized as Class 1 or 2 locations and would be subject to a quarterly leak survey with the interval between surveys not exceeding 135 days. Therefore, operators are given leeway of an additional half month to conduct a patrol if there is challenging weather or terrain.

PHMSA understands the desire of certain commenters for even more stringent environmental standards and similar sentiments expressed during the GPAC meeting. As such, PHMSA made changes in this final rule to require operators patrol certain pipelines more frequently than previously required but less frequently than proposed in the NPRM. PHMSA believes the patrol frequencies established in § 192.705 balance the safety of people, property, and the environment with the cost to operators.

Regarding the comments requesting a minimum patrol interval of 6 times per year at intervals not exceeding 75 days, PHMSA partially adopted the recommendation, as this final rule requires operators to survey pipelines in Class 3 and Class 4 locations at that frequency. However, this final rule requires operators to patrol pipelines in Class 1 and Class 2 locations quarterly, at an interval not exceeding 135 days. PHMSA acknowledges that the requirements in this final rule for pipelines in Class 1 and Class 2 locations do not meet the commenters' desired patrol frequency because pipelines in these locations have a lower safety risk, which justifies a less frequent patrol interval. Basing the patrolling frequencies on a pipeline's class location was unanimously supported by the Committee. Due to the safety benefit to people and property, PHMSA has adopted the Committee's recommendation.

PHMSA appreciates the concerns raised by the Committee and commenters regarding PHMSA's assumption that all operators conduct monthly patrols. While some operators do perform frequent aerial patrols, that practice is not universal in the industry, particularly for operators of regulated gas gathering lines and transmission lines that are operated as part of a distribution system. Since the baseline compliance is lower in the final RIA than PHMSA initially estimated in the PRIA, the costs for operators to perform monthly patrols was substantially higher, which helped PHMSA determine that a lower frequency of patrols is appropriate.

While, as mentioned by public comments, visual right-of-way patrols by themselves are less effective at detecting leaks than the instrumented leak surveys required by § 192.706 or integrity assessments per IM requirements, they are a cost-effective means of supplementing less frequent surveys with advanced leak detection technology, ensuring that some leaks are detected and therefore repaired earlier. This is illustrated in the EPA standards described in section II.E, which supplements periodic OGI or EPA Method 21 surveys with monthly AVO surveys (analogous to patrols). Equally important, patrols are a cost-effective way to address some integrity threats like excavation damage and earth movement, which can prevent leaks and ruptures from occurring in the first place entirely. As such, this final rule calls for less frequent patrols than originally proposed in the NPRM; however, the resulting outcome is more frequent patrols on net in comparison to § 192.705 as it existed prior to this rulemaking. Frequent patrols increase the likelihood that operators promptly identify threats to the integrity of a pipeline or visual indications of significant leaks. Decreasing the time between patrol intervals reduces the amount of time during which leaks could degrade into catastrophic integrity failures, allow gas to build up and ignite, or emit a substantial amount of methane or flammable, toxic, or corrosive gases to the environment. The RIA contains a more detailed response to these comments. PHMSA has ensured that this final rule is compliant with OMB Circular A-4 and case law.[250]

Leak Survey Frequency for Gas Transmission

The Committee unanimously supported the NPRM with respect to the frequency of gas transmission leak surveys at § 192.706. Therefore, in this final rule, PHMSA is finalizing the more frequent survey frequencies it proposed for 1) assemblies such as valve sites, flanges, tie-ins, ILI launchers, and ILI receivers, and 2) for non-odorized pipelines in HCAs, Class 3

[250] Circular A-4 is a guidance document issued by the Office of Management and Budget to agencies directing them on how to conduct high-quality and evidence-based regulatory analysis. The cases of *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); and *Cape Hatteras Access Pres. All. v. U.S. Dep't of Interior*, 344 F. Supp. 2d 108, 130 (D.D.C. 2004) were cited on page 48 of the Industry Trade's comment (PHMSA-2021-0039-25350).

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locations, and Class 4 locations. While the general survey frequency requirements applicable to most pipelines in this final rule are the same as what PHMSA proposed in the NPRM, this final rule makes minor changes to clarify the proposed requirements related to specific concerns raised by public comments regarding the Alaska North Slope, which are discussed later in this section. Increased leak survey frequencies in the final rule apply to offshore facilities on platforms above the water line and to onshore pipelines in HCAs and Class 3 and Class 4 locations. Per § 192.5(b)(1)(i), offshore pipelines are, by definition, in Class 1 locations. Comments received regarding gas gathering pipelines, and PHMSA's responses to those comments, will be discussed in section III.P. Also, comments received regarding pipelines transporting hydrogen gas will be discussed in section III.Q.

PHMSA noted significant commenter support of annual leak surveys for valves, flanges, and facilities outside of HCAs. Therefore, in this final rule, PHMSA is requiring operators to survey valves, flanges, and facilities, regardless of whether they are in HCAs, either quarterly or twice per calendar year, depending on the class location of the pipeline or facility. This aligns with current EPA requirements for compressor stations to monitor fugitive emissions components quarterly with OGI or EPA Method 21. This more frequent surveying of valves, flanges, and other aboveground facilities is supported by methane emissions information described in section II.B. Leaks from line pipe represent a small portion of total gas transmission emissions. This is because aggregate emissions estimates and emissions factors from the GHGI, described in section II.B, demonstrate that fugitive emissions from other types of facilities, such as gas transmission compressor stations and gas distribution meter and regulator stations, have a much larger contribution to total emissions. While the GHGI does not separately estimate emissions from other types of gas transmission assemblies outside of compressor stations, PHMSA expects the emissions profile for such facilities is more like gas transmission compressor stations and distribution meter and regulator stations than line pipe. Compared with welded steel pipelines, such facilities have much more complex configurations, including components such as flanges, valves, pressure regulating and limiting devices, and other devices and fittings with more opportunities for leakage from connections. Therefore, more frequent leak surveys of valves, flanges, and other aboveground facilities will help ensure operators detect and repair leaks at these facilities earlier, resulting in a significant reduction in total emissions. Finally, changes from the NPRM in this final rule with respect to the performance standards applicable to the use of mobile, aerial, satellite, and remote survey equipment and OGI cameras should reduce the cost of performing surveys with such equipment. This is discussed in further depth in the RIA as well as in this document in section III.D.

In response to concerns regarding quarterly leak survey requirements, only certain portions of pipelines in Class 4 locations, as outlined at § 192.706(b)(1)(i) through (iv) of this final rule, are required to be surveyed quarterly due to the higher safety consequences were an incident to occur in such a location. These facilities that have potentially elevated safety consequences include transmission pipelines in HCAs; pipelines transporting gas without an odor or odorant; pipelines known to leak based on material, design, or past O&M history; and valves, flanges, pipeline tie-ins with valves and flanges, ILI launcher, and ILI receiver facilities. The increased likelihood of leakage from components, such as valves, flanges, pipeline tie-ins with valves and flanges, and launcher and receiver facilities as discussed in section II.B., pose increased public health and safety risks to nearby populations and environmental risk from fugitive emissions. All other pipelines have leak survey frequencies of either once or twice a year depending on the pipeline's characteristics, such as class location. Consistent with the GPAC recommendation and requests from industry commenters, the compliance timeline for the amended leak survey frequencies has been revised to January 1, 2028, approximately 3 years after the date of publication. This extension provides time for operators to hire and qualify individuals to perform leak surveys and procure leak survey equipment. In comparison to other components of this final rule, such as the ALDP and leak grading and repair, which will require the establishment of new procedures, the revised leak survey intervals will not require significant changes to plans and procedures.

In response to a commenter requesting operators bi-annually survey pipelines in HCAs in Class 4 locations and expressing concerns about survey frequency in sparsely populated areas, Class 4 pipelines have an inherently higher safety risk due to the proximity of population centers to the pipeline, which also translates to higher benefits compared to other gas transmission pipelines. Pipelines in Class 4 locations are generally rare; PHMSA's annual report data for 2023 shows that, across the U.S., there were only 745 miles of Class 4 gas transmission pipeline, accounting for only 0.2 percent of all onshore gas transmission pipeline mileage.[251] The RIA considers the costs borne by operators by more frequent leak surveys.

[251] U.S. Department of Transportation's Pipeline and Hazardous Materials Administration's 2023 Gas Transmission Annual Report. The data cited in this sentence is from an April 22, 2024, data pull. See docket for webpage. phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids

In response to comments discussing the existing utility of IM, for most gas transmission and regulated gathering pipelines, the leak survey frequency remains unchanged. Operators may continue to conduct more frequent leak surveys as a preventative and mitigative measure as stipulated by their IM program. This final rule revises the leak survey frequency for pipelines in Class 4 locations with specific characteristics per § 192.706(b)(1)(i)-(iv). The GPAC supported the proposed leak survey frequencies unanimously; therefore, the final rule retains the proposed survey frequencies for these facilities.

In response to the comment provided by Boston University School of Public Health and Engineers for Healthy Energy, PHMSA did not propose composition-specific leak survey frequencies, as they are contemplated by § 192.903(c).[252] Specifically, the potential impact radius (PIR) in § 192.903(c) includes a factor for natural gas, which considers the heat of combustion and is affected by the composition of natural gas. For gas transmission pipelines, an operator can use the PIR to determine a pipeline's HCA designation, which informs leak survey frequency. For gas gathering pipelines, the exception from a 1-year survey in § 192.9(f) considers an operator's potential impact circle (which is a circle created using the PIR), and therefore considers the composition of the transported gas. PHMSA may consider making

[252] PHMSA does not formally collect data on operators' natural gas composition on their annual report (OMB Control No. 2137-0522). If PHMSA were to collect this information in the future, there would be no practical way for operators to correlate natural gas composition to a particular facility at a particular point in time except when it develops into an incident.

changes to the annual report and other information collection activities in this area of concern in the future.

In response to the commenter's second request for PHMSA to consider the proximity of nearby populations, residences, and sensitive receptors when determining leak survey frequencies, PHMSA agrees and has based many of the leak survey frequencies of this final rule on a pipeline's class location and HCA designation. A pipeline's class location and HCA status are based on the density and types of structures located in the vicinity of the pipeline and are intended to address these specific risks. Class 4 locations are the most densely occupied locations, and this final rule requires these pipelines to be surveyed more frequently.

In response to commenters' concerns regarding the exemption for surveying leaks on gathering lines outside of Class 1 and Class 2 locations, the Committee recommended the scope of the exception from operators using leak detection equipment be limited to submerged piping. Therefore, in this final rule, PHMSA has removed the exception from operators using leak detection equipment to perform leak surveys for pipelines outside of Class 1 and Class 2 locations and for onshore pipelines. This will help ensure that operators use high-quality leak detection technology to perform leak surveys on all gas transmission and regulated gas gathering pipelines that are not submerged.

In response to a commenter's concern that it is impracticable for operators to perform more frequent leak surveys on pipelines in HCAs in Class 1 and Class 2 locations due to difficulties in achieving the proposed ALDP performance standard with aerial leak surveys, PHMSA has made changes, in this final rule, to the ALDP performance standards in

§ 192.763(b) to be compatible with commercially available aerial survey methods and address the practicability of more frequent surveys.[253] At § 192.706(b)(1), this rulemaking finalizes more frequent surveys for aboveground facilities, non-odorized pipelines, pipelines known to leak, and pipelines in HCAs: all of which have a greater propensity to leak or present a higher risk to people or property. In response to the commenters' assertion that pipelines in Class 1 and Class 2 locations pose little risk to people, property, and the environment due to their rural nature and lower populations, while pipelines in Class 1 and Class 2 locations are generally located in less densely populated areas, individuals living near these pipelines are just as affected by pipeline leaks and incidents. Additionally, Class 2 locations contain more than 10 but fewer than 46 buildings intended for human occupancy in area that extends 220-yards on either side of the centerline of any continuous 1-mile length of pipeline. Assuming that there are a few people living in each home, this may result in a sizable population in a Class 2 location. Furthermore, exposure to HAPs, which are found in natural gas, affects humans regardless of whether they live in a rural or urban area.[254]

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[253] See section III.D. for additional discussion of the ALDP performance standard for gas transmission pipelines.

[254] A 2011 report contended that hazardous air pollutants (HAPs) including n-hexane, 2,2,4-trimethylpentane, and the benzene, toluene, ethylbenzene, and xylenes (BTEX) compounds were in transmission pipeline natural gas, but failed to provide its methodology. A 2022 study by Nordgaard et al. investigated data from FERC from 2017 to 2020. Ultimately, the authors found that for transmission pipeline natural gas, the HAP concentrations for hexane, toluene, ethylbenzene, xylenes, hydrogen sulfide, and radon exceeded the EPA Reference concentration limits. The EPA Reference concentration limit is an estimation of continuous inhalation exposure concentration to people (including sensitive subgroups) that is likely to be without risk of deleterious effects during a lifetime. This article only included 45 percent of US onshore natural gas transmission pipeline mileage, because FERC does not require natural gas HAP composition data for some project applications. The authors converted HAP concentrations from weight percent or mole percent to ppm. https://iopscience.iop.org/article/10.1088/1748-9326/ac9295. Nordgaard, et al, "Hazardous air pollutants in transmission pipeline natural gas: an analytic assessment" *Environmental Research Letters* (Oct. 3, 2022).

Though the Committee did not make specific recommendations with respect to pipelines located in the Alaskan North Slope, PHMSA understands the unique considerations and climate challenges that can affect the practicability of performing leak surveys in the winter months in that area. The proposed amendments to the leak survey frequencies in the NPRM did not specifically take into consideration the unique operating environments of pipelines in the Alaska North Slope. Thus, in this final rule, §§ 192.706(b)(1)(iv) and (v) apply explicitly to pipelines located in Alaska north of the Brooks Range, resulting in an annual leak survey requirement for the vast majority of gas transmission lines in the Alaska North Slope. The PIPES Act of 2020 does not permit PHMSA to relax leak survey frequencies under this proceeding. Therefore, non-odorized pipelines in the Alaska North Slope in Class 3 and Class 4 locations must continue to be surveyed at the existing leak survey intervals of two times each calendar year in Class 3 locations or at least four times each calendar year in Class 4 locations. For Class 3 locations, operators may perform these leak surveys during the spring and fall. PHMSA is not aware of any Class 4 location pipeline mileage in the Alaska North Slope. If necessary, operators may seek a special permit from PHMSA exempting them from the requirements of § 192.706(b)(1)(iv) through the special permit process in § 190.341.

As discussed in more detail in section III.Q, PHMSA acknowledges the public comments and the Committee recommendation that portions of the NPRM are not appropriate for dedicated hydrogen pipelines (i.e., pipelines transporting a gas that contains more than 50 percent of hydrogen gas, by volume). Accordingly, PHMSA has included in this final rule an exemption at § 192.706(a)(2) for operators of such pipelines from the use of ALDP-compliant leak detection equipment while still requiring the use of certain leak detection equipment for the required leak surveys. Notwithstanding, the leak survey requirements in § 192.706(b) apply to hydrogen gas pipelines, as proposed.

As described in the discussion of the repair timelines in section III.I, this final rule extends the timeline for operators to repair grade 2 leaks on gas transmission pipelines within 12 months and permits an operator to request an extension of a leak repair if the required repair timeline in § 192.760 is impracticable. These provisions should address commenter concerns regarding the practicability of repairing leaks discovered during a fall survey during the winter, when conditions might make that repair impracticable, under the proposed 6-month repair timeline.

PHMSA appreciates the comment requesting more frequent leak surveys of valve sites, launchers and receivers and tanks on gathering lines. This final rule implements a more rigorous surveying schedule than existed previously. Balancing the Committee's unanimous vote in support of the gas transmission pipeline leak survey frequencies and other received comments, this final rule retains the proposed increased survey interval for valves, flanges, launchers and receivers, pipeline tie-ins, valves, and flanges on gas transmission and Type A and B regulated gas gathering lines at § 192.706(b)(1)(i). Per this final rule, these facilities are to be surveyed four times per calendar year when in Class 4 locations and twice per calendar year when in Class 1, Class 2, or Class 3 locations. PHMSA declines to adopt an increased frequency for tanks on gathering lines in this final rule to allow for additional opportunities for technical evaluation and public feedback.

PHMSA appreciates the comments regarding the desire to simplify the proposed leakage survey intervals. In response, PHMSA has created a table to better communicate the applicable leakage survey frequency in § 192.706(b)(1). The agency declines to adopt more frequent leakage surveys across the board due to the relatively low risk of leaks on gas transmission lines beyond the areas targeted in the final rule in § 192.706 (b)(1)(i) through (iv).

PHMSA appreciates the comment supporting operators performing more frequent leak survey intervals and using less-sensitive leak survey equipment that is cheaper and simpler to use. Based on Committee recommendations and other public comments, this final rule attempts to strike a balance between operators conducting more frequent surveys while using appropriate technologies. Based on public comments and the GPAC recommendation, PHMSA has revised the single ALDP performance standard proposed in the NPRM to provide options for standards appropriate for different types of facilities and survey technologies. These changes should allow operators to select the most appropriate and cost-effective technology for leak surveys of each portion of their system, which addresses concerns about restricting the use of cost-effective equipment. For example, adopting standards for screening surveys and alternative standards for aboveground equipment makes it easier to use lower-cost survey methods, such as aerial and OGI. Changes to the performance standard for leak detection equipment are discussed further in section III.D. In response to a concern regarding including a list of distribution pipeline materials prone to leak in the transmission portion of the regulations, the commenter's suggestion to strike the list of pipelines known to leak based on material at proposed § 192.706(b) has been adopted in this final rule.

Commenters expressed concern that a single pipeline segment could be subject to multiple leak survey requirements based on its location. In response, PHMSA clarifies in this final rule that an operator must use the most frequent interval applicable to the pipeline segment should more than one survey interval apply at § 192.706(b). More broadly, PHMSA acknowledges that the need to tailor requirements to target the greatest benefit or to address specific concerns from public comments is often in tension with a desire for simple rules. The final rule has attempted to simplify to the extent practicable by relying on longstanding classifications of risk such as class location and HCA status to the extent practicable.

In response to a commenter's concern about PHMSA considering removing references to HCAs and class locations from the leak survey frequencies, PHMSA expects an operator to know where their HCAs are and locate HCAs as a basic requirement of an IM program. Most gas transmission pipelines will be subject to an annual survey per § 192.706(b)(1)(v). Only a fraction of pipelines is affected by class location-specific leak survey frequencies. Survey frequencies based on class location are only required for pipelines known to leak, transmission lines in HCAs, non-odorized gas transmission lines, and aboveground equipment. Those types of pipelines can be reasonably identified in advance prior to surveying for leaks. Regarding the concern about creating an unintended policy outcome of operators subsequently decreasing the number of pipelines identified as HCAs in order to alter the number of leak surveys they must perform by using Method 2 instead of the Method 1,[255] PHMSA's final rule adopts changes to

[255] The HCA definition in § 192.903 provides two methods for identifying HCAs. Method 1 is primarily based on class location, while Method 2 is based on the number of structures within the potential impact radius of any

the ALDP and repair requirements recommended by commenters and by the Committee that address cost concerns and reduce the incentive for operators to attempt to reclassify pipelines as being in non-HCAs. In addition, Method 2 of HCA determination is already overwhelmingly favored by operators under the status quo, with 78 percent of HCA miles identified by operators using Method 2 according to information submitted in part T of PHMSA's 2023 gas transmission annual report.[256] Finally, operators of gas gathering lines are not required to identify HCAs; therefore, HCA-specific standards would not apply to gas gathering facilities.

PHMSA has determined that certain existing leak survey requirements are insufficient, as they allow for extended periods of time when leaks can degrade into integrity failures; allow gas to build up and ignite; or emit a substantial amount of methane or flammable, toxic, or corrosive gases to the environment. Any leak of methane can entail a public safety risk, especially leaks from a transmission pipeline, which generally operates at a higher pressure and capacity than a distribution line and is often non-odorized.

Multiple individuals commented on the proposed requirement for operators to use leak detection equipment during transmission line leak surveys. Some commenters were opposed to such a requirement and wanted PHMSA to maintain the requirements as they existed prior to the

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given point on the pipeline. Class location is based on a class location unit, defined in § 192.5 as an area extending 200 meters on either side of any continuous mile of pipeline, while the area of a potential impact radius is defined in § 192.703. Since a class location unit is substantially larger in area than a potential impact radius, method 1 tends to be more conservative.

[256] U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration's 2023 Annual Report Data from May 6, 2024. See docket for webpage. https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids

NPRM. Other commenters were against the exemption from the requirement for operators to use leak detection equipment when performing leak surveys of pipelines in non-HCA Class 1 or Class 2 locations. PHMSA discusses and addresses comments related to the technology standards in greater detail at section III.D.

As described above, PHMSA has determined that the leak survey frequencies adopted in the final rule, when combined with the periodic patrol requirements described in this section and more flexible ALDP standards described in section III.D and III.E, are appropriate and practicable for addressing the need to identify leaks on gas transmission and regulated gas gathering lines. For this reason, today's final rule does not adopt recommendations from public comments to add exceptions or extensions for "difficult-to-monitor" or "unsafe-to-monitor" components similar to those adopted by the EPA for fugitive emissions monitoring surveys as described in section II.E. PHMSA expects that the vast majority of such components will be within compressor stations subject to those EPA standards and exempted from PHMSA LDAR standards as described in section III.G. For any remaining components that may be more challenging to survey, the changes in the final rule should address concerns about safety and practicably performing leakage surveys. The vast majority of gas transmission and regulated gas gathering lines are in in class 1 locations subject to an annual leak survey frequency compared with the quarterly instrumented survey requirement for EPA emissions monitoring in 40 CFR 60.5397b. While other components must be surveyed more frequently, this is limited to those components where leakage is more likely or more consequential, as described above, and therefore more frequent surveys are justified. Finally, the revisions to the ALDP performance standard in § 192.763(b) described in section III.D provides operators additional flexibility to deploy leak detection technologies that can meet leak survey requirements without elevating or otherwise putting operator personnel into hazardous conditions. PHMSA expects aerial surveys to be the most common method for performing leakage surveys of gas transmission lines, and such surveys do not require direct access to the facility at all. Additionally, the final rule adopts standards for open-path handheld equipment and OGI surveys that can detect leaks at a safe distance and adopts both leakage rate and concentration standards for continuous monitoring sensors that can be used to detect leaks in areas that may be difficult to access.

General Comments

Visual right-of-way patrols in conjunction with effective leak surveys are useful in the identification of leaks. Specifically, more frequent patrols help ensure that an operator's pipeline infrastructure is being monitored for potential integrity threats such as excavation and earth movement in addition to providing the ability to detect visual indications of significant leaks. The identification of the threat of encroachments by third parties or potential land movement and visual indications of blowing gas or dead vegetation during a patrol may prevent a future or larger incident. Patrols by themselves, however, are not sufficient for effective leak detection. Leaks that are not visible or do not have a significant leakage rate cannot be identified by a right-of-way patrol.

Increased gas transmission leak surveys in HCAs are appropriate. Comprehensive leak and incident prevention in HCAs starts with an IM program supported by information learned in both patrol and leakage surveys. An IM program is used to evaluate the overall integrity of a pipeline to aid in the prevention of pipeline releases. The patrolling and leak survey programs provide detection once a leak has occurred, or encroachment activity is present. While TIMP is more prescriptive than DIMP, data indicates a continuation of incidents and leaks in HCAs. In fact, despite HCA mileage remaining relatively constant, there is a slight increasing trendline for leaks. An IM program is intended to prevent failure and mitigate the consequences should a failure to occur by threat identification, integrity assessment and remediation or repair activities. An in-line inspection tool (most frequently used for integrity management assessments) is capable of detecting anomalies due to corrosion, stress-corrosion cracking, manufacturing, and construction. ILI-detectable anomalies in some instances can and have developed into leaks. Therefore, while ILI is an important tool in IM, increased leak surveys for gas transmission lines in HCAs are merited. More frequent leakage surveys aid in the early identification of these leaks before they reach the definition of an incident. Annual report data from 2010 to 2023 demonstrates that on average the transmission incidents in HCAs is more than two times the number of leaks found in HCAs. This data supports the need for increased leak survey frequencies as IM by itself does not eliminate leaks and incidents.

An ILI tool is unable to detect issues related to equipment, incorrect operations, third party damage, weather, and other. From 2005 to 2023, 85 percent of ILI non-detectable leaks were caused by equipment failure. For those issues involving equipment, not detectable with an ILI tool, gas transmission leak survey frequencies are specified. Equipment includes valves, flanges, pipeline tie-ins with valves and flanges and ILI launcher and ILI receiver facilities. Annual report data from 2010 to 2023 also shows that of the 49 leaks reports, one third of those leaks were found on equipment that would not be identified through an ILI assessment and could go undetected. Therefore, the new gas transmission leak survey frequency equipment is warranted.

Leaks per mile on Type A gas gathering pipelines has remained relatively constant between 2013 and 2023, according to annual report data. The leaks per mile for Type B gathering pipelines has decreased from 2013, but it remains more than ten times higher than for Type A. Gas gathering pipelines are not subject to IM and therefore threat determination is not used to identify potential issues regarding the integrity of the pipeline. Leak surveys are necessary to locate leak indications leading to repair. The increased gas gathering leak survey frequencies codified in this final rule will address this issue.

In response to comments requesting PHMSA provide specific methane emission data and cost data to support an increase in patrols and leak surveys, the agency has updated the RIA for this rulemaking as appropriate and encourages readers to review the RIA for an in-depth response to comments related to the costs and benefits of this final rule.

In direct response to the commenter who cited the Boles et al. (2023) article to argue that leaks from offshore pipelines have limited impact on the environment, PHMSA is aware that the conditions found in California, such as weather, geological structures, and geological materials, may not be directly applicable to other environments with offshore pipelines. Additionally, to the extent that some leaks from submerged pipelines may not result in impacts to public safety and the environment, this is accounted for by allowing operators to use visual leak survey methods for submerged pipeline segments in both the proposal and this final rule. Leaks that do release methane to the atmosphere or result in other environmental harms would be visually perceptible due to bubbles or a sheen of gas condensate on the water's surface. Finally, leaks from platform piping above the waterline is also covered by this final rule, and that leaks on such piping would not be absorbed by sea water and are accessible to operators using leak detection equipment.

As a response to the concern regarding jurisdictional authority on private property, PHMSA did not change any jurisdictional definitions of service lines in this rulemaking. The location of a pipeline facility on private property does not, by itself, affect its jurisdictional status or regulatory classification, nor does this final rule change the jurisdictional status or regulatory classification of any pipeline facility. To the extent that a pipeline being on private property would affect the practicability of performing leak surveys, the revised leak detection performance standard of this final rule better accommodates leak surveys via allowing continuous monitoring, remote sensing, and mobile or aerial surveys. These changes should reduce the difficulty of operators performing leak surveys on pipelines located on private property. Similarly, for distribution lines, the property line is immaterial to the classification of a service line or any pipeline. PHMSA permits longer survey frequencies for distribution pipelines inside buildings, which addresses some of the concerns from the Committee and the public regarding the challenge of operators gaining access to pipelines located inside of private property. PHMSA appreciates the suggestions to reconsider exceptions for odorized pipelines and to institute a performance standard for the odorization of gas pipelines, specifically gas distribution lines, at a level of one-tenth the LEL or below, and PHMSA will potentially consider these items in future rulemakings. Meanwhile, PHMSA encourages its State partners and operators to consider improvements in odorization, as both State regulators and operators have the authority to pursue odorization standards beyond the Federal minimum that PHMSA sets.

PHMSA considered a few alternatives related to gas transmission and gas gathering leak surveys and patrols. First, PHMSA considered an alternative where the leak survey and patrol requirements were those that were proposed in the NPRM. While this scenario had higher monetized benefits, there were accompanying higher monetized costs. Specifically, costs would increase by a factor of 17, when compared with the requirements in this final rule. Therefore, this alternative was not selected.

Second, PHMSA considered an alternative, which would exclude Type C and offshore gathering lines from the final rule, while the other requirements for all other pipeline types remained the same as for the final rule. This alternative had lower costs than the aforementioned alternative (requirements proposed in the NPRM) as well as the requirements implemented in the final rule. For this alternative, excluding type C mileage means that the vast majority of gas gathering line mileage and all mileage that is not currently subject to existing leak surveys are not required to follow the requirements in this final rule or proposed in the NPRM. While this yields a lower cost, the benefits decrease precipitously, because surveying type C mileage produces significant benefits. This alternative was not selected because excluding Type C gas gathering lines from the scope of the final rule significantly reduces quantified net benefits from $683 million in 2023 dollars to only $53.3 million.

C. Liquefied Natural Gas Facility Leakage Surveys—§ 193.2624

1. Summary of PHMSA's Proposal

Prior to this final rule, part 193 did not require operators to perform periodic surveys of LNG facility components and equipment for methane leakage to the atmosphere. Accordingly, the current regulations also do not specify what technologies or equipment must be used if leak surveys are performed. However, as described in section II.B, equipment leaks and other fugitive methane emissions are the second-largest methane emissions source from LNG storage facilities and the largest methane emissions source from LNG export terminals.

In the NPRM, PHMSA proposed to add a new § 193.2624 to require operators of LNG facilities to conduct quarterly methane leak surveys on equipment and components within their facilities containing methane or LNG using leak detection equipment. Per the proposal, operators would then address any methane leaks and abnormal operating conditions discovered in accordance with the operator's maintenance or abnormal operating procedures, as applicable, and on a schedule established within its procedures. For such surveys, PHMSA proposed a minimum equipment sensitivity requirement of 5 ppm—along with validation and calibration requirements—consistent with the proposed requirements at § 192.763 governing the performance of leak detection equipment described in section III.I. PHMSA also proposed that operators of LNG facilities must maintain records of the leak survey equipment sensitivity validation and calibration for 5 years after the operator performs the leak survey. PHMSA proposed that the leak survey, leak detection equipment, remediation, and documentation requirements would apply to all LNG facilities, including mobile, temporary, and satellite facilities.

Also, consistent with PHMSA's proposed revisions to part 191 LDAR reporting requirements for part 192-regulated gas pipeline facilities, PHMSA proposed conforming revisions to its annual report form for part 193-regulated facilities[257] to help ensure meaningful reporting by operators of LNG facilities of all methane leaks detected or repaired pursuant to § 193.2624.

Lastly, PHMSA proposed an effective date for the proposed requirements of 6 months after the publication date of a final rule in this proceeding.

PHMSA explained in the NPRM that these proposed enhanced methane leak and repair requirements would improve public safety by allowing for operators to promptly identify and remediate potential ignition sources within part 193-regulated LNG facilities as well as reduce a key source of fugitive GHG emissions from those facilities.

2. Summary of Public Comments

Senator Cruz, et al.[258] opposed the full scope of proposed changes to the LNG facility regulations, reasoning that they would be contrary to congressional intent and statutory language.

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[257] PHMSA, Form 7300.1-3, "Annual Report Form for Liquefied Natural Gas Facilities (Oct. 2014). The instructions for Form 7300.1-3 states that "a non-hazardous release that can be eliminated by lubrication, adjustment, or tightening is not a leak." PHMSA, Instructions for Form 7300.1-3 at 4 (Oct. 2014). That historical understanding is inconsistent with PHMSA's understanding of the PIPES Act of 2020 premise that all leaks of methane are hazardous to the environment because they contribute to climate change. PHMSA did not, however, propose in this NPRM to modify the historical reporting exception with respect to releases of other, non-methane, hazardous materials within an LNG facility.

[258] Senator Ted Cruz, Senator Todd Young, Representative Sam Graves, and Representative Troy Nehls. (PHMSA-2021-0039-26620).

NAPSR and Occidental Petroleum Corporation expressed general support for proposed §§ 193.2605 and 193.2624.

The Industry Trades and multiple operators broadly asked PHMSA to consider that LNG facilities may already be subject to overlapping requirements under statutes or regulations administered by another government agency. Multiple operators asked PHMSA to provide an exception for LNG facilities similar to the compressor station exception proposed for part 192-regulated pipeline facilities. In addition, the Industry Trades and National Grid suggested that it is unnecessary to apply leak survey requirements to mobile or temporary LNG facilities as they "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."[259,260] The Industry Trades and multiple operators further asked PHMSA to consider whether leak survey requirements need to apply uniformly to all components and areas within an LNG plant.

The MD Attorney General, et al., the PST, the EDF, and Healthy Gulf supported requiring quarterly methane leak surveys for LNG facilities.

Kinder Morgan, Golden Pass LNG Terminal, and the Industry Trades recommended either exempting from the leak survey requirements components that are challenging for operators to access or monitor or allow operators to survey them at a reduced frequency. For surveying unsafe-to-monitor and difficult-to-monitor components, Golden Pass LNG Terminal suggested a frequency of no more than two times per calendar year, and Northeast Gas

[259] AGA, API, AFPM, APGA, GPA, INGAA, and NGA. (PHMSA-2021-0039-26350).
[260] National Grid, LLC. (PHMSA-2021-0039-26194).

Association (NGA) suggested PHMSA allow LNG operators to designate alternative leak survey intervals in their procedures. Further, NGA suggested that PHMSA should identify the types of components that are subject to any leak survey requirements, as there are types of components, or even entire areas or portions of LNG facilities, that are not susceptible to leaks. Physicians for Social Responsibility Pennsylvania, the PST, Clean Air Council, Honeywell International Inc., Waterspirit, a form letter campaign, and an individual commenter suggested PHMSA consider requiring all LNG facilities to perform continuous monitoring, quarterly inspections, and leak repairs within 1 month of discovery. The PST supported PHMSA considering whether continuous emission monitoring is appropriate for LNG facilities.

Kinder Morgan argued that the proposal for quarterly monitoring of LNG facilities lacks technical support and is not cost-effective. Kinder Morgan was joined in their comments by Southwest Gas Corporation and Great Basin Gas Transmission Company (Great Basin) and the NGA, who stated that large-scale LNG facilities are manned on a 24-hour basis and are required to have continuous gas monitoring (with an alarm), which allows for the immediate notification of larger leaks. Finally, Kinder Morgan suggested that requiring LNG operators to detect and remediate small leaks at more frequent intervals lacks technical justification.

Texas Pipeline Association (TPA) and Texas Chemical Council (TCC) asked PHMSA to clarify the allowable environmental and operational parameters for leak surveys in proposed § 193.2624(b)(1). The TPA and TCC expressed concern that the 5-foot equipment proximity requirement in proposed § 193.2624(b)(2) could lead to dangerous conditions for operator personnel when calibrating leak detection equipment. The commenters explained that leak detection equipment is commonly housed within a docking station when undergoing calibration and system checks and that performing validation with a known concentration of gas in that environment would subject employees to unsafe conditions. The NGA provided comments and revised regulatory text that suggested that each operator must determine their own calibration requirements and intervals based on manufacturer's recommendations.

The EDF and Healthy Gulf commented that LNG operators should be subject to the ALDP and technology standards. The PST suggested that PHMSA develop a leak detection technology standard for LNG facilities with the same equipment sensitivity requirement as other part 192-regulated facilities.

The Industry Trades and National Grid stated that the proposed threshold of "5 parts per million or more of within 5 feet of the component or equipment" for the capability of leak detection equipment used for leak surveys of LNG facilities is unnecessary and unreasonable, stating that the proposed "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."[261,262] The Industry Trades also added that the 5-ppm-within-5-feet standard would prohibit the use of a wide range of commercially available leak detection technologies. Southwest Gas Corporation and Great Basin supported this position by stating that PHMSA does not need to set a minimum sensitivity of 5 ppm to provide a protective threshold of detection sensitivity while conducting leak surveys.

[261] AGA, API, AFPM, APGA, GPA, INGAA, and NGA. (PHMSA-2021-0039-26350)
[262] National Grid, LLC. (PHMSA-2021-0039-26194)

Honeywell, a leak detection equipment provider, suggested that rather than use a prescriptive standard of 5 ppm measured 5 feet from the equipment, PHMSA should correlate the proposed concentration standard to a leak rate, allow for flexibility in the minimum sensitivity of the equipment to account for higher-frequency surveying (in particular continuous monitoring), and require a minimum probability of detection. Honeywell suggested that the proposed standard of 5-ppm would not be appropriate for continuous monitoring but that continuous monitoring with less-sensitive equipment can provide significant advantages for LDAR programs for LNG facilities, including detecting leaks earlier, pinpointing leak locations, and providing complete and accurate leak and fugitive emissions data than possible without continuous monitoring.

The PST suggested that PHMSA require operators to remediate leaks discovered during leak surveys of LNG facilities on a quarterly basis, as that would support the proposed quarterly leak survey frequency. They added that PHMSA should further implement a repair schedule for leaks found at these facilities. The EDF and Health Gulf supported more stringent leak survey and repair requirements than what PHMSA proposed. The Industry Trades and several operators suggested that PHMSA was not justified in requiring LNG operators to remediate small leaks and establish prescriptive leak survey frequency intervals.

An individual commenter requested PHMSA include emissions from natural gas processing plants in its final RIA. The Industry Trades and multiple operators expressed concern that PHMSA did not calculate the full potential costs for implementing proposed § 193.2624 in the PRIA. An operator encouraged PHMSA to provide a definition of a leak in part 193 so there is a clear understanding of that term throughout PHMSA's regulations.

The Industry Trades suggested that the proposed 6-month deadline for complying with the leak survey requirements for LNG facilities is impracticable, with an operator proposing PHMSA provide a one-year implementation schedule. The NGA, along with the Industry Trades, also stated that use of the terms "equipment" and "components" at § 193.2624 introduces uncertainty, as those terms are used already in the part 193 regulations at §§ 193.2007 and 193.2401.

3. GPAC Deliberation Summary

The Committee discussion of the NPRM proposals for leak surveys of LNG facilities at §§ 193.2605 and 193.2624 occurred on Monday, March 25, 2024, within a broader discussion of all proposed requirements for LNG facilities and facilities transporting hydrogen gas and blends of hydrogen gas and natural gas. PHMSA initiated the discussion with a summary presentation of the proposed requirements and the supporting reasoning, including a discussion of the costs and benefits, and an overview of material comments received from stakeholders on the proposal during the public comment period. The Committee then provided an opportunity for members of the public present at the meeting to offer comments in response to PHMSA's presentation. Several stakeholders, representing a range of LNG facility operators, industry associations, and public safety and environmental safety advocacy groups, offered comments during the public comment period. Some commenters representing industry noted that not all LNG facilities are of the same size or complexity, and that a single leak survey frequency or technology might not be appropriate to be standardized across the sector. Industry stakeholders noted that many LNG plants are equipped with stationary or fixed gas detectors that provide continuous monitoring, that complex, large-scale LNG facilities may have areas inaccessible to handheld leak detection tools, and suggested that PHMSA allow either continuous monitoring through fixed gas sensors or handheld leak detection survey tools as well as consider alternative methods of leak detection. An advocacy group stakeholder supported PHMSA's proposed leak survey intervals and a repair timeline of 1 month from discovery and requested that PHMSA clarify that LNG operators would be required to satisfy the ALDP standards. The stakeholder also noted the close proximity of LNG plants to communities and the need for leak surveys to quickly identify leaks. In contrast, an industry stakeholder suggested that an annual leak survey of LNG facilities was sufficient. An industry stakeholder suggested that PHMSA should consider alternative emission minimization methods proposed by the industry. Industry stakeholders requested that PHMSA account for the unique characteristics of peak-shaving LNG facilities in developing leak repair timeframes and stated that the proposed leak detection standards for LNG facilities are unnecessary for mobile and temporary LNG facilities. The Committee also heard concerns that PHMSA was duplicating a regulatory framework already in place for LNG facilities by the EPA, commenting that those EPA regulations provide adequate protection to public safety and the environment. Those commenters suggested that PHMSA should consider similar exceptions for LNG facilities as those proposed for compressor stations subject to EPA requirements.

The Committee asked PHMSA to clarify how the EPA regulations might apply to LNG facilities to the extent that information was available to PHMSA, and after a lengthy discussion, generally agreed that the previously agreed upon exemption, discussed in section III.B of this final rule, would be appropriate to extend to LNG facilities. The Committee discussed that operators would have the burden to affirmatively demonstrate, in the case of abutting regulatory environments (i.e., EPA, State agencies, and PHMSA), which regulatory regime is governing at the facility or portions of the facility. The Committee further discussed the appropriateness of applying the proposed leak survey frequency, and procedural leak detection equipment and repair requirements, to the many types of LNG facilities (e.g., terminals, large-scale, small-scale, mobile and temporary, and satellite). An industry member on the Committee suggested that they were not recommending any exclusions to the leak survey requirements for certain facilities but that perhaps PHMSA should make a distinction based on the size or complexity of the LNG facility or based on the proximity of the facility to high-population or disadvantaged communities. The Committee also discussed the application of continuous monitoring at LNG facilities, including large and complex LNG facilities, such as marine terminals. A member of the Committee representing the public explained for the record that continuous monitoring that already exists in these facilities can be helpful in identifying the presence of methane in the area, but they are not particularly good at pinpointing the location of leaks and other emissions. The Committee also discussed the measures operators of LNG facilities should take in response to identified leaks and acknowledged again that the many existing types of LNG facilities complicate the application of a single LDAR standard for all facilities. The Committee generally reached consensus on the appropriate standard for addressing leaks on LNG facilities considering the practicability of customer impacts, operating restraints, and environmental concerns. A

Committee member representing the public suggested that PHMSA consider immediate repair timelines for grade 1 leaks at LNG facilities and within 3 months for other leaks, which consequently led the Committee to consider alternative repair timelines that may be appropriate for leaks at LNG facilities. Committee members emphasized the differences in the ability to schedule and perform leak repairs on pipelines and LNG facilities, noting the continuous nature of operations at LNG export facilities, the complexity and importance to national security of large-scale LNG facilities, and the need for PHMSA to consider these and other unique factors to LNG facilities in developing repair timelines. Some Committee discussion emphasized the need to develop a regulatory backstop for repair timelines, balancing the unique challenges to LNG facilities discussed above. Although PHMSA did not propose any specific grading criteria for LNG leaks and proposed that LNG operators address leaks according to their procedures, the Committee considered the appropriateness of applying an equal leak grading repair timeline framework as that recommended by the Committee for part 192-regulated pipelines. Ultimately, these discussions informed the Committee's recommendation, supported by the majority of the members, that PHMSA require operators immediately repair grade 1 leaks, as those were defined for transmission pipelines, and repair grade 2 leaks as soon as practicable, but not to exceed 1 year, unless PHMSA and the applicable State authority approved an extension.

4. GPAC Recommendation

The Committee voted 13-1 that the provisions in the NPRM regarding leak surveys for LNG facilities at § 193.2624 were technically feasible, reasonable, cost-effective, and practicable if four changes were made. First, the Committee recommended leak surveys not be required for portions of an LNG facility subject to EPA emissions monitoring requirements. Second, the Committee recommended that, for small-scale LNG facilities, PHMSA consider survey frequencies aligned with Committee recommendations for gas transmission pipelines, which ranged in frequency from quarterly to annually, depending primarily on the pipeline's class location. Third, the Committee recommended that PHMSA consider repair timelines consistent with the recommendations of the GPAC applicable to gas transmission lines—requiring operators to take immediate and continuous action for grade 1 leaks until the leak is fixed, and repairing grade 2 leaks as soon as practicable, but not to exceed 1 year, unless an extension of the leak repair is approved following notification to PHMSA and the applicable State authority. Fourth, the Committee recommended that PHMSA apply a leak detection limit consistent with what the GPAC recommended for gas transmission pipelines.[263]

5. PHMSA Response

PHMSA considered all the submitted comments regarding the NPRM's proposals for leak surveys of LNG facilities, including leak grading and repair requirements. While section 113 does not explicitly address LNG facilities, Congress granted PHMSA broad general authority to prescribe regulations for gas pipeline facilities, including LNG facilities, under 49 U.S.C. 60102(a) and specific authority to prescribe O&M standards for LNG facilities under 49 U.S.C. 60103(d). Finally, nothing in the PIPES Act or its legislative history explicitly prohibits

[263] See section III.D.3: The committee recommendation included two options for pinpointing the source of a leak: 1) a 10 kg/hr flow rate standard for screening surveys, including a follow-up investigation of leak indications with handheld equipment (5 ppm, 5ppm-m, or 1 percent LEL) or 2) a leakage survey with a handheld or mobile equipment with an instrument sensitivity of 5 ppm or ppm-m. The Committee also recommended that all flow-rate-based ALD technology must have a probability of detection of 90 percent.

PHMSA from issuing LDAR standards for LNG facilities, and such standards reinforce and clarify LNG facility operators' obligation to eliminate hazardous leaks and minimize releases of natural gas under section 114 of the PIPES Act. Therefore, PHMSA disagrees with commenters that claimed that PHMSA has no clear authorization to issue new LDAR or procedure manual regulations for LNG facilities. For further information on PHMSA's authority to issue leak detection and repair standards for LNG facility are addressed in detail in section III.T..

Additionally, PHMSA assessed an alternative where operators of LNG facilities would not be required to conduct periodic leak surveys or mitigate release volumes during operational blowdowns and where the section 114 mandate regarding procedure manual revisions for LNG facilities would not be codified. Leaks on LNG facilities pose similar risks to the environment and public safety as leaks on other pipeline infrastructure covered by this rulemaking, and PHMSA determined that this alternative it examined would forego environmental and public safety benefits from reducing leaks, leaving the risks from those leaks unaddressed.

The RIA explains that PHMSA annual report data likely understates leaks on LNG facilities, and PHMSA's analysis, which does not monetize benefits related to leak surveys on LNG facilities, nevertheless could still underestimate the benefits associated with operators of LNG facilities performing prescriptive leak surveys and implementing section 114 of the PIPES Act of 2020.

PHMSA has elected to exercise this authority to propose requirements for a LDAR program that is appropriate for LNG facilities and procedure manual requirements consistent with other proposals for gas pipeline safety in this rulemaking. As detailed in the NPRM, equipment leaks and other fugitive emissions are the second largest methane emissions source from LNG storage facilities and the largest methane emissions source from LNG export terminals. PHMSA did not intend for operators of LNG facilities to apply the comprehensive, ALDP framework proposed for part 192-regulated gas pipeline facilities as discussed in section IV.B of the NPRM. Further, the proposed LDAR program requirements applicable to LNG facilities were intentionally and deliberately tailored to conform to the unique operations and regulations of LNG facilities. These standards address the need to mitigate such emissions in conjunction with the self-executing requirements in section 114, which requires operators to have and implement an inspection and maintenance plan that addresses the extent to which the plan will contribute to public safety, eliminating hazardous leaks and minimizing releases of natural gas from pipeline facilities, and protection of the environment.

PHMSA appreciates the many public comments regarding concerns of overlapping or conflicting regulations for portions of LNG facilities that are not part of distribution systems, which may be subject to EPA methane emission monitoring requirements in 40 CFR part 60. PHMSA also appreciates the discussion and recommendation by the Committee to not require leak surveys at LNG facilities that are subject to EPA, or individual State, methane fugitive emission monitoring and repair requirements. While LNG facilities are not defined as an affected facility in the EPA regulations at 40 CFR Part 60 Subparts OOOO through OOOOb or designated facilities at 40 CFR Part 60 Subpart OOOOc, an LNG facility located within the natural gas processing, transmission, or storage segments may include facilities that are covered by those requirements. LNG facilities located within a local distribution system (defined by the

EPA as downstream of the custody transfer station for a distribution company) are not covered by these requirements.[264] Accordingly, in this final rule, PHMSA is including an exception to the leak survey requirements for those components and portions of LNG facilities that are subject to EPA, or individual State, methane fugitive emission monitoring and repair requirements in 40 CFR Part 60 Subparts OOOOa through OOOOc.

Regarding the frequency of leak surveys at LNG facilities, the NPRM proposed quarterly leak surveys for all portions of LNG facilities. The Committee recommended that the frequency of leak surveys for small-scale LNG facilities be aligned with the gas transmission leak survey frequencies, which, per this final rule, are quarterly to annually, depending on the pipeline's class location. The discussion by the Committee identified "small-scale facilities" to mean satellite LNG facilities that are generally part of gas distribution pipeline systems but also included small peak-shaving facilities located on transmission lines and small-scale liquefaction facilities. PHMSA does not currently define "small-scale" LNG facilities, and PHMSA did not propose such a definition in the NPRM. However, PHMSA agrees that a one-size-fits-all approach to prescribing leak survey frequencies for LNG facilities does not consider the unique differences between the different types and sizes of LNG facilities and their different risks to the public and the environment. Therefore, PHMSA is prescribing in this final rule a modified leak survey frequency of one time per calendar year, with a maximum interval between surveys not exceeding 15 months, for LNG facilities with an individual container capacity of less than

[264] The EPA has provided FAQs providing guidance on the applicability of these requirements for LNG facilities at the following link. https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-operations/frequently-asked-questions-general#lng.

264,000 gallons, or a total aggregate capacity of less than 1,056,000 gallons, consistent with the industry's understanding of "small-scale" LNG facilities.[265]

PHMSA supports the use of advanced and continuous monitoring systems to detect fugitive emissions at LNG facilities.[266] However, not all continuous monitoring systems can detect smaller leaks or are expansive enough to detect leaks in all portions of the facility, such as those components covered with thermal insulation or located high up. Accordingly, this final rule prescribes reduced leak survey frequencies for portions of LNG facilities that are continuously monitored for methane leaks, which leverages advanced technology for continuous monitoring to detect for larger methane leaks while ensuring operators conduct periodic surveys to survey and detect smaller leaks on all methane- or LNG-carrying components subject to the leak survey requirements at § 193.2624.

Compared to the proposal in the NPRM, and consistent with the recommendation from the Committee, PHMSA is finalizing in this rulemaking the proposed frequency of leak surveys on those components and portions of LNG facilities with continuous methane monitoring from quarterly to annually, not to exceed 15 months. To the extent a portion of an operator's LNG facility is covered by continuous monitoring and is also identified as unsafe-to-monitor or difficult-to-monitor, the annual leak survey interval would apply. The quarterly frequency of leak survey required for all other LNG facilities is adopted in this final rule as proposed in the NPRM.

[265] NFPA 59A, "Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)" (2019).

[266] Using continuous monitoring provides consistent and reliable information for emission reductions. See 89 FR 16875 (Mar. 8, 2024).

The NPRM proposed that leak detection equipment must be capable of detecting and locating all methane leaks producing a reading of 5 ppm or more within 5 feet of the equipment and component being surveyed, which was similar to the sensitivity performance standard proposed for gas transmission lines. The Committee recommended that PHMSA revise that requirement to apply a detection limit consistent with the Committee recommendation for leak detection equipment on gas transmission lines, which was a 10 kg/hr flow rate standard for screening surveys, followed by a 5 ppm, 5 ppm-m, or 1 percent LEL threshold for a follow-up survey to investigate and pinpoint the source of indicated leaks. Alternatively, per the Committee's recommendation, operators of gas transmission lines could perform a 5 ppm or 5 ppm-m standard comprehensive leakage survey with handheld or mobile leak detection equipment. The recommendation from the Committee also included a 90 percent probability of detection standard for all flow rate-based advanced leak detection technology. One percent LEL is equivalent to 500 ppm for methane.

The NPRM proposed a leak detection equipment minimum sensitivity standard for leakage surveys conducted on LNG facilities commensurate with the minimum sensitivity standard proposed for 49 CFR part-192 regulated gas pipelines. Therefore, the Committee's recommendation that PHMSA align the leak detection equipment standards for LNG facilities with those recommended by the Committee for gas transmission lines is consistent with the NPRM, with similar emissions monitoring standards established by the EPA, and is supported by public comments PHMSA received. PHMSA is adopting its proposal for leak detection equipment used for leak surveys of LNG facilities to have a minimum sensitivity of 5 ppm or 5 parts per million-meter (ppm-m). Consistent with the Committee recommendation, PHMSA is adopting a separate performance standard of a minimum flowrate detection limit of 10 kg per hour with a 90 percent probability of detection for leak detection equipment used for screening leak surveys or continuous monitoring sensors. This standard would apply to continuous monitoring that is already common at many large-scale LNG facilities. Consistent with the Committee recommendation and public comments, PHMSA is finalizing a performance standard of 1 percent LEL (500 ppm of methane) for leak detection equipment that can be used for pinpointing the source of leak indications for components that are not buried, unsafe to monitor, or difficult to monitor. PHMSA believes that this leak detection equipment standard is consistent with the PIPES Act of 2020 section 113 mandate by requiring equipment capable of detecting leaks that may not be a hazard to human safety but that are hazardous to the environment. Finally, in response to the Committee recommendation to avoid unnecessary overlap with EPA requirements, PHMSA is including an exemption to the calibration, validation, and leak detection capability requirements being finalized in this rulemaking at paragraphs (b) and (c) of 49 CFR 193.2624 for the use of certain OGI instruments. This exemption will allow for the use of OGI or EPA Method 21 instruments (i.e., leak detection equipment) that are compliant with EPA regulations at Appendix K of 40 CFR part 60, or Appendix A-7 for 40 CFR part 60, respectively. Additionally, PHMSA is including a similar exemption to the leak survey frequencies, calibration, validation, and leak detection capability requirements being finalized in this rulemaking at paragraphs (a), (b) and (c) of 49 CFR 193.2624 for those components or portions of LNG facilities subject to EPA fugitive methane emission monitoring and repair requirements at 40 CFR 60.5397a, 40 CFR 60.5397b, or requirements included in an approved state plan, tribal, or federal plan, at least as stringent as EPA's model rule found at 40 CFR 60.5397c. There were no Committee comments or recommendations regarding the NPRM proposals related to procedures and records requirements for LNG facility leak surveys and leak detection equipment validation and calibration. Regarding the comment that the "allowable environmental and operational parameters" described at 49 CFR 193.2624(b)(1) of the NPRM needed clarification, PHMSA was referring to the ranges of environmental and operational conditions generally included in the leak detection equipment manufacturer's instructions for the specific piece of leak detection equipment. These conditions often include allowable ranges for, among other things, wind speed, humidity, temperature, and dwell time, that must be followed for the equipment to perform according to the stated specifications. Regarding the comment that the proposed requirement to validate the sensitivity of leak detection equipment before initial use could lead to a dangerous condition, PHMSA believes that the calibration and validation steps can be performed separately and in different locations, with the validation step not required to be performed while the leak detection equipment is housed within a docking station in an enclosed space or environment. Regarding the comment received regarding at what frequency operators of LNG facilities are expected to perform these validation and calibration requirements, PHMSA intended to allow operators to determine frequencies that are consistent with the leak detection equipment manufacturer's instructions and recommendations and the operator's experience with such equipment, given the wide range of available leak detection equipment and methodologies.

In response to these comments, PHMSA is clarifying the requirements surrounding the required validations and calibrations for LNG facility leak survey methods and leak detection equipment. Accordingly, in this final rule, PHMSA is requiring operators to qualify each leak survey method and type of detection equipment the operator uses to comply with the leak survey requirements of § 193.2624. In doing so, the operator must: (1) define the environmental and operational conditions for which the leak detection equipment is and is not permissible (to include environmental conditions, such as wind speed and ambient air temperature, and operational conditions, such as effectiveness of the leak survey method for certain components and the effective range of the leak survey method or leak detection equipment); (2) validate that each type of leak detection equipment meets the applicable performance standard for leak surveys detailed in the paragraphs above (to include testing the leak detection equipment with a known concentration or amount of gas or having documentation of an equivalent performance test performed by the equipment's manufacturer); and (3) calibrate and maintain leak detection equipment consistent with the equipment manufacturer's instruction. Additionally, maintenance of this leak detection equipment is meant to require equipment recalibration—according to the manufacturer's instructions—or replacement in the event of equipment malfunction or failure.

The NPRM did not propose that LNG operators apply the comprehensive ALDP framework, as discussed in section IV.B of the NPRM, for part 192-regulated gas pipeline facilities to avoid the confusion that might result from overlaps or conflicts with existing regulatory requirements and best practices in the National Fire Protection Association standard, "Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)" (NFPA

59), which is in incorporated by reference in PHMSA regulations at § 193.2801 and contains requirements for LNG facilities and other standard practices.[267] Instead, the NPRM proposed tailored LDAR program requirements applicable to LNG facilities that included addressing any methane leaks and abnormal operating conditions in accordance with written maintenance procedures or abnormal operating procedures.

The Committee recommendation on this topic, with a vote of 13-1, further supported by comments from public and environmental commenters, was more prescriptive than what PHMSA proposed in the NPRM. PHMSA recognizes the benefits of a more prescriptive framework for leak grading and repair timelines; however, the more prescriptive leak grading and repair requirements recommended by the Committee, as applied to LNG facilities, were not proposed in the NPRM. It would be consistent with the intent of the NPRM at § 193.2605 and section 113 of the PIPES Act of 2020 to require that operators prioritize leaks based on potential impacts to persons, property, and the environment. Therefore, in this final rule, and consistent with the intent of the NPRM, PHMSA is requiring operators of LNG facilities to prioritize leaks based on hazards to public safety and the environment when addressing leaks and abnormal operating conditions identified during leak surveys, according to their written maintenance or abnormal operating procedures. PHMSA is pursuing a separate rulemaking[268] in which the agency may consider leak monitoring, surveying, and patrolling requirements at LNG facilities

[267] 88 FR 31890 at p. 31932.

[268] See RIN 2137-AF45, "Pipeline Safety: Amendments to Liquefied Natural Gas Facilities."

more holistically, and will take into account the discussion and recommendation from the Committee.

PHMSA appreciates the comments it received regarding the usage of the term "equipment and components" and is revising the use of the proposed phrase "equipment and components" to "component," in this final rule, when referring to any part, or system of parts functioning as a unit in an LNG facility that contains methane or LNG. This is consistent with the existing definition of component in § 193.2007.

Although not raised by a commenter, PHMSA has identified an opportunity to reduce duplicative leak survey recordkeeping requirements when comparing the maintenance recordkeeping requirements that existed prior to this rulemaking at § 193.2639 and proposed § 193.2624(c), which will lower recordkeeping burdens without diminishing the quality of records. Section 193.2639 obliges each operator to keep a record at each LNG plant of the date and type of each maintenance activity performed on each component to meet the requirements of this part. Additionally, § 193.2639 requires operators to keep these maintenance records for a period of not less than 5 years. The leak survey requirements for LNG facilities are found at § 193.2624, which is within subpart G of part 193. As such, the recordkeeping requirements that existed at § 193.2639 prior to this rulemaking would apply to the new leak survey requirements at new § 193.2624. Accordingly, in this final rule, PHMSA is moving the recordkeeping requirements it proposed for leak surveys of LNG facilities to § 193.2639 and is amending this section to include a new paragraph (d) that explicitly requires leak survey records, consistent with the NPRM. For operators to comply with the recordkeeping requirements of the amended

§ 193.2639, each operator must keep a record of each leak survey, including records of the equipment sensitivity validations and calibrations required by operators' procedures; how the operator addressed any leaks or abnormal operating conditions; and if applicable, the determination of which components or portions of the LNG facility are covered by EPA emissions monitoring standards described at § 193.2624(f).

In the NPRM, PHMSA proposed to codify the leak survey requirements for mobile and temporary LNG facilities with all other LNG facilities at § 193.2624. During the drafting of this final rule, PHMSA identified that § 193.2019 would be the most appropriate location to codify the leak survey requirements for mobile and temporary LNG facilities. Section 193.2019 identifies the requirements for part 193-regulated mobile and temporary LNG facilities for peak-shaving application, for service maintenance during gas pipeline systems repair and alteration, or for other short-term applications. Specifically, paragraph (a) specifies that mobile and temporary LNG facilities operated in compliance with applicable sections of the 2001 version of NFPA-59A are not required to meet the requirements of part 193. Paragraph (b) of § 193.2019 includes a requirement that, notwithstanding the exemption for the remainder of part 193, a State agency having jurisdiction over pipeline safety in the State in which the portable LNG equipment is to be located must be provided with, among other details, a location description for the installation at least 2 weeks in advance of placing such a facility into service.[269]

[269] PHMSA, 62 FR 41312, "The safety guidelines and the restrictions for LNG mobile facilities in applicable sections of NFPA 59A (1996 edition) provide an adequate level of assurance of public safety. The safety guidelines are identical to those required as conditions for waiver except for the requirement shown as follows: "The State agency having jurisdiction over pipeline safety in the State in which the portable LNG equipment is to

To clarify and incorporate the proposed requirements, in this final rule, for operators to perform leak surveys on mobile and temporary LNG facilities, PHMSA is revising § 193.2019 by amending paragraph (a) to clarify that mobile and temporary LNG facility operators must comply with the notification requirement in paragraph (b) as it existed prior to this rulemaking and leak survey requirements, which are moved from § 193.2624(a) as proposed to new paragraph (c) of this section. Additionally, in response to public comments, PHMSA finds it unnecessarily burdensome for mobile and temporary LNG facilities, many of which are in service for less than 180 days at a time, to be subject to periodic (i.e., quarterly) leak surveys. Therefore, PHMSA is removing the periodic leak survey requirement for mobile and temporary LNG facilities; however, PHMSA is requiring operators of mobile and temporary LNG facilities, in § 193.2019(a), to perform an initial leak survey for mobile and temporary LNG facilities shortly after placing the facility in service to verify that the facility is free of methane and LNG leaks in accordance with § 193.2019(c).

Accordingly, in § 193.2019(c)(1), PHMSA is extending the leak survey requirements in § 193.2624(b) and (c) to mobile and temporary LNG facilities. These requirements cover leak survey method qualification and leak detection equipment qualification, validation, calibration, maintenance, and performance standard. To the extent that operators of mobile and temporary

be located must be provided with a location description for the installation at least 2 weeks in advance, including to the extent practical, the details of siting, leakage containment or control, firefighting equipment, and methods employed to restrict public access, except that in the case of emergency where such notice is not possible, as much advance notice as possible must be provided." […] Operators will no longer need a waiver from Part 193 requirements for mobile facilities if they comply with the applicable sections of NFPA 59A and the requirement stated above."

LNG facilities opt to use OGI instruments or are subject to EPA fugitive methane emission monitoring and repair requirements at 40 CFR 60.5397a, 40 CFR 60.5397b, or requirements included in an approved state plan, tribal, or federal plan, at least as stringent as EPA's model rule found at 40 CFR 60.5397c, the exemptions at 49 CFR 193.2624(e) and (f) are available.

In § 193.2019(c)(2), PHMSA is finalizing recordkeeping requirements for leak surveys of mobile and temporary LNG facilities, recognizing that operators of mobile and temporary LNG facilities are not required to otherwise comply with part 193 recordkeeping requirements at § 193.2639. These recordkeeping requirements are intentionally limited to those records necessary to demonstrate compliance with § 193.2019(c)(1) and obligate operators to maintain records in accordance with § 193.2639(a), meaning that operators must keep such records for a period of not less than 5 years.

Finally, in § 193.2019(c)(3), PHMSA is finalizing the requirement that operators of mobile and temporary LNG facilities must have and follow written procedures for performing and documenting leak surveys in accordance with paragraph (c) of § 193.2019, including meeting the requirements of each subparagraph therein. PHMSA, recognizing that operators of mobile and temporary LNG facilities are not required to otherwise comply with part 193 procedure manual requirements at §§ 193.2503 and 193.2605, finds it incompatible with the intent of § 193.2019 to require operators of mobile and temporary LNG facilities to have procedures for performing, reviewing, and addressing leaks as those requirements are being finalized in §§ 193.2605(b)(3) and 193.2624(d) of this rulemaking. PHMSA reasons, as discussed above, that operators of mobile and temporary LNG facilities are not required to comply with requirements to have procedures for abnormal operating conditions and safety-related conditions (SRCs) in accordance with §§ 193.2011, 193.2503 and 193.2605, and therefore a less-prescriptive but more flexible requirement, which is aligned with section 114 of the PIPES Act of 2020, is appropriate.[270]

PHMSA expects that these enhanced methane leak survey and repair requirements will improve public safety by allowing operators to promptly identify and remediate potential ignition sources within part 193-regulated LNG facilities as well as reduce a key source of fugitive GHG emissions from those facilities. Additionally, eliminating product losses results in cost savings that improve the competitiveness of LNG storage and export facilities, further increasing the net benefits of these requirements.

As PHMSA has largely aligned the provisions in this final rule regarding LNG facility leak surveys to the recommendations of the Committee, with deviations that increase operator flexibility, PHMSA expects that these requirements are reasonable, technically feasible, cost-effective, and practicable for affected LNG facility operators. Some LNG facility operators may operate transmission pipelines supplying natural gas to their facilities; those operators could use their existing leak survey practices as a foundation for the development of leak survey requirements tailored to their LNG facilities. Further, insofar as leak surveys using leak detection equipment are widely understood to be essential tools for identifying and mitigating threats to the integrity of any gas pipelines transporting methane, they are among the practices that reasonably

[270] Notwithstanding § 193.2019, part 191, which includes requirements for identifying and reporting incidents and SRCs and submitting annual reports, applies to mobile and temporary LNG facilities.

prudent operators should adopt in ordinary course to protect public safety and the environment from releases of methane from equipment and components in LNG facilities and minimize the loss of a commercially valuable commodity.

Viewed against those considerations and the compliance costs estimated in the RIA for this rulemaking, PHMSA expects its amendments will be a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this final rule and its supporting documents.

D. Advanced Leak Detection Program: Performance Standard—§ 192.763(b)

1. Summary of PHMSA's Proposal

General

Section 113 of the PIPES Act of 2020 requires PHMSA to issue performance standards for operator LDAR programs reflecting the capabilities of commercially available, advanced leak detection technologies and practices. To satisfy this mandate, PHMSA proposed to introduce a new § 192.763 to require operators establish a written ALDP, which must satisfy PHMSA-specified leak detection performance standards. In keeping with Congress's direction to require use of "advanced leak detection technologies and practices," the NPRM included two proposed performance standards: one setting a minimum sensitivity for leak detection equipment, expressed in ppm (proposed § 192.763(a)(1)(ii)), and a second setting a minimum leak detection capability for an operator's leak detection program as a whole (proposed § 192.763(b)).

Minimum equipment sensitivity standard

For the minimum equipment sensitivity performance standard (§ 192.763(a)(1)(ii)), PHMSA proposed to require that all leak detection equipment operators use for leak surveys, pinpointing leak locations, investigating, and inspecting leaks must have a minimum sensitivity of 5 ppm. As described in sections II.D.4 and IV.B of the NPRM, this 5-ppm threshold is consistent with the performance of FIDs and other natural gas detectors in common use and widely available today. The NPRM described OGI devices, open-path infrared (IR) devices, and other commercially available advanced technologies with sensitivities measured in ppm-m units.[271] Point concentration measures are not directly comparable or convertible to path-integrated ppm-m measures, however open-path detectors with sub-5 ppm-m sensitivity are in common use by gas pipeline operators.

Program-wide performance standard

For the program-wide performance standard (§ 192.763(b)), PHMSA proposed to require that an operator's ALDP be capable of detecting all leaks that produce a reading of 5 ppm of gas or greater when measured from a distance of 5 feet from the pipeline or within a wall-to-wall paved area. This program-wide standard was also consistent with commercially available equipment sensitivities, but it was focused on the characteristics of the leak and its environment. The 5-ppm-within-5-feet benchmark was intended to represent a minimum-size leak on a buried pipe that could be detectible with a device sensitive to 5 ppm and that could be measured during

[271] Ppm-meter is a ''path integrated'' summation of measured gas concentration used for open-path devices that sums gas concentration per meter measured up to the effective range in front of the device. Sensitivity may be higher at closer ranges depending on the specific technology used.

a walking survey with handheld leak detection equipment that is already in widespread use. However, operators would have flexibility to design their ALDPs to incorporate different equipment types (including aerial, ground-based mobile, and continuous monitoring systems), equipment sensitivities, leak survey frequencies, and other leak detection and pinpointing techniques in combination to help ensure that all leaks meeting the 5-ppm-within-5-feet benchmark would be detected. These program elements are discussed in greater detail in section III.E below.

For even greater flexibility, PHMSA proposed to allow an operator to use an alternative program-wide ALDP performance standard in accordance with proposed § 192.763(c). An operator's alternative program-wide performance standard could entail the use of alternative leak detection technology, including less-sensitive technology, or alternative programs than those proposed to be required under § 192.763(a)(1). This process would be available for gas transmission and gas gathering pipelines in Class 1 and Class 2 locations, and any part 192-regulated pipeline facility, including distribution lines, transporting flammable, toxic, or corrosive gases other than natural gas.[272]

[272] Although PHMSA's default performance standard for all part 192-regulated gas pipelines is based principally on commercially available, advanced *methane* leak detection technology for use with natural gas pipelines, commercially available, advanced leak detection technology for use with *other* part 192-regulated gas pipeline facilities may (when considered either separately or within a suite of mutually-reinforcing technologies) offer comparable leak detection ability. Further, as explained in the paragraph above, the NPRM contemplated operators of gas pipeline facilities transporting gases other than natural gas (e.g., hydrogen) may request the use of an alternative leak detection performance standard and supporting leak detection equipment.

Alternative Performance Standards

In the NPRM, PHMSA explored the feasibility of operators using other leak detection technologies, such as flow rate-based equipment, but did not initially propose a flow rate-based performance standard because of concerns about commercial availability of flow rate-based leak detection equipment. PHMSA invited comment on whether and how such technologies could be incorporated into either a minimum equipment sensitivity performance standard or a program-wide performance standard in the final rule. PHMSA also requested comments on whether and in what manner it could integrate technologies that may not have specified sensitivities, including continuous pressure wave monitoring, fiber optic sensing, OGI, and light detection and ranging (LIDAR)-based detection technologies.

2. Summary of Public Comments

Sycamore Gas Company expressed concern with "applying ALDP standards that are impractical and do not necessarily yield tangible improvements in public or environmental safety." Philadelphia Gas Works supported minimum performance standards and PHMSA's understanding of the importance of affording flexibility to operators. Multiple operators recommended removing the word "advanced" from the phrase "advanced leak detection program" or clarifying that the modifier "advanced" does not mandate the use of the "newest" or "most sensitive" technology available.

The NGA said that "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." Bridger

Photonics, Inc. recommended that an ALDP standard for transmission and gathering pipelines be "defined as emission rate detection sensitivity for the rate of emission to the atmosphere" because remote sensing detects atmospheric gas concentrations. The commenter continued that the detection sensitivity requirements should be tied to a probability of detection, preferably a 90 percent probability of detection, to ensure the requirement is meaningful. Rep. Rick Larsen, et al.[273] encouraged PHMSA to consider ALDP standards for equipment that is capable of accounting for local meteorological conditions.

NiSource Inc. and Heath Consultants Incorporated supported the proposed 5 ppm standard. The NGA and multiple operators said the proposed 5 ppm standard exceeds PHMSA's statutory mandate to protect the environment by exceeding the EPA's regulatory definition of a leak without a clear explanation or technical basis and is inconsistent with State-jurisdictional regulatory requirements.

Multiple operators stated that while there is commercially available leak detection technology that can detect a methane concentration of 5 ppm or less, the equipment may not be readily available or accessible to the entire industry. The Industry Trades claimed the NPRM did not indicate whether PHMSA verified vendor claims about leak detection equipment availability.

The TPA and TCC said a one-size-fits-all approach to leak detection is inconsistent with the way leak detection works in the field. The GPTC recommended that PHMSA consider the

[273] U.S. Representatives Rick Larsen (WA), Donald M. Payne, Jr. (NJ), Valerie P. Foushee (NC), Colin Z. Allred (TX), Julie Brownley (CA), Salud Carbajal (CA), André Carson (IN), Steve Cohen, Mark DeSaulnier (CA), John Garamendi (CA), Jesús G. Garcia (IL), Jared Huffman (CA), Henry C. Johnson (GA), Jr., Robert J. Menendez (NJ), Seth Moulton (MA), Grace F. Napolitano (CA), Eleanor Holmes Norton (DC), Chris Pappas (NH), Patrick K. Ryan (NY), Marilyn Strickland (WA), and Frederica S. Wilson (FL). (PHMSA-2021-0039-25826).

different types of leak detection equipment and the environments in which they are used. Similarly, the Clean Hydrogen Future Coalition recommended that PHMSA ensure that performance standards are flexible enough to meaningfully accommodate new, innovative, and effective leak detection technologies that may be developed in the future for unblended hydrogen pipelines. Multiple industry representatives proposed that PHMSA simplify the ALDP sensitivity requirements to be addressed by an emissions detection "method" consistent with the EPA leak definition of 500 ppm when using EPA Method 21 for methane fugitive emissions monitoring surveys pursuant to 40 CFR 60.5397a or 40 CFR 60.5397b(c)(8).[274]

Bridger Photonics, Inc. stated that the proposed standard is based on the sensitivity of point sensors used during a walking survey, which is not practical for transmission or gathering line leak surveys. INGAA said the 5-ppm threshold is not feasible for transmission pipelines, and they joined the Industry Trades in commenting that the proposed performance standard for leak detection equipment is inconsistent with the EPA's emissions monitoring requirements at EPA Method 21 and would result in numerous false positives. INGAA therefore suggested that PHMSA instead establish different standards for different facility types, which was similar to the recommendation made by the Industry Trades. The NGA and an operator said basing the ALDP standard off such a low threshold could lead to false positives and would add significant burden on companies while providing little to no environmental benefit.

Multiple operators and the Industry Trades commented that the proposed standard is inappropriate because it may restrict operators from using other advanced leak detection

[274] And the emissions guidelines for State and Tribal Plans described in the model rule in 40 CFR 60.5397c(c)(8).

technology, such as mobile, aerial, and satellite-based platforms. Multiple operators requested that PHMSA clarify the applicability of the 5-ppm-within-5-feet standard to various types of equipment, stating that the 5-ppm-within-5-feet standard is not achievable by most existing aerial equipment. INGAA, the Industry Trades, and multiple operators said that the "ppm" unit is not useful for measuring concentrations of gas remotely or over large areas at one time.

Northeast Ohio Natural Gas Corporation, the AGA, the Energy Association of Pennsylvania, Philadelphia Gas Works, and Florida Natural Gas Association, et al.[275] expressed support for a multi-tiered ALDP that maintains the 5-ppm sensitivity for handheld equipment but allows for higher sensitivity thresholds for broader mobile, aerial, and satellite technology. The NGA, the Industry Trades, and multiple operators suggested a 5-ppm standard for handheld equipment and 500 ppm for mobile, aerial, satellite, optical, infrared, or laser-based leak detection platforms. Kinder Morgan, Inc. recommended a 500-ppm standard for leak surveys, and, in the event of a detected leak, the operator would pinpoint the leak using technology meeting the 5-ppm sensitivity.

Alaska Oil & Gas Association said the proposed standard failed to account for technological constraints in cold weather environments, stating that many leak detection technologies have minimum temperature thresholds, below which they will not function as

[275] American Gas Association, Energy Association of Pennsylvania, Florida Natural Gas Association, Gas & Oil Association of West Virginia, Indiana Energy Association, Iowa Utility Association, MEA Energy Association, Michigan Electric and Gas Association, New Jersey Utilities Association, Northeast Gas Association, Northwest Gas Association, Tennessee Gas Association, and Wisconsin Utilities Association. (PHMSA-2021-0039-26218).

designed. Therefore, the commenter recommended a 500-ppm standard until a more robust analysis of available technology is performed to determine an achievable level for all operators.

Consolidated Edison Company of New York, Inc. discussed the discrepancy between the proposal to require leak detection devices be specified to a 5-ppm standard and the proposal to require leak grades be determined based on percentage LELs (leak grading criteria are described in greater detail in sections III.H through III.J). The commenter discussed the inability to measure both values at once and the difficulty of converting them. The commenter requested that PHMSA provide a list of commercially available equipment that can provide both readings at once as well as carbon monoxide alarm monitoring that is necessary for emergency responders. GTI Energy recommended that PHMSA clarify that open-path gas detector equipment measuring in ppm-m rather than in point concentration would be allowed.

Multiple industry representatives recommended that PHMSA work with the regulated industry to develop standards for leak detection and urged PHMSA to incorporate a technology-neutral, performance-based approach to encourage continued investment and development of new leak detection technologies that may increase efficiency and accessibility.

Oleksa and Associates, Inc. said the 5-ppm standard for the ALDP is unnecessary because most of the currently used leak detection equipment meets that requirement. ABB Inc. recommended setting the standard to less than 1 ppm with an effective measurement time of less than 5 seconds. East Goshen Township Pipeline Task Force supported the proposed performance standard to 5 ppm within 5 feet, stating that this value is 1 percent of the LEL for methane in air, and this specification is consistent with commercially available leak detection equipment.

Multiple operators expressed that the 5-foot standard for methane detection is unreasonable, too prescriptive, and ambiguous, discussing scenarios where compliance with the proposed standard would be difficult or impossible. The Industry Trades and multiple operators recommended removing the 5-feet requirement from the leak detection standard, stating that PHMSA failed to consider real-world characteristics of leaks, including pipeline burial depth, soil conditions, atmospheric conditions, plume behavior, and probability of detection for the equipment being used.

CSU/SMU discussed research that was performed on the placement of methane detection equipment and its ability to detect below-ground pipeline leaks. The commenters asserted that aboveground leak detection methods do not directly translate to underground leaks.

GPA Midstream Association, et al. said that if PHMSA retains the proposed 5-feet requirement for the ALDP standard, then PHMSA should clarify that the threshold only applies for the purposes of determining the sensitivity of the equipment and does not require the equipment to be located within 5 feet of the pipeline. Heath Consultants Incorporated said the performance standard should include a T50 response time[276] requirement of 2 to 3 seconds or less because surveys conducted with equipment with a higher response time will not reliably detect gas leaks at 5 ppm.

The Industry Trades commented that current leak detection technology measures concentration, not flow rate, and asserted that concentration is the most important metric for pipeline safety purposes to avoid a risk of nearing or exceeding the LEL.

[276] T50 refers to the time it takes a gas detector to provide a reading of 50 percent of the actual gas concentration.

NiSource Inc. supported PHMSA providing an alternative methodology to the concentration-based standard and suggested that PHMSA work with advanced leak detection experts to define an appropriate alternative. GHGSat Inc. said that the concentration of gas can be highly variable even within the same plume of methane from a single source.

The Industry Trades commented that PHMSA should not rely on concentration alone for its ALDP standard, and the API submitted, on behalf of the Industry Trades, a technical report prepared by Highwood Emissions Management that compared the proposed concentration standard with flow rate standards of 1, 3, 10, and 30 kg/hr. That report concluded that aerial surveys could not achieve the proposed concentration standard and that adopting a less restrictive flowrate standard, such as 4 kg/hr, achieves significant emissions reductions more cost-effectively by enabling low-cost aerial surveys and reducing costs from the repair of very small leaks.[277] Multiple industry representatives requested that PHMSA replace the concentration-based standard with a flow rate-based standard in alignment with the EPA's approach, which measures in kg/hr. Citing research from Lamb et.al,[278] GTI Energy,[279] METEC,[280] and results from their own leak surveys, Picarro, Inc. commented that concentration is poorly correlated with actual emissions and that the smallest leaks have a relatively minor impact on total emissions. Because of those considerations, they commented that leak release rate is a more

[277] Highwood Emissions Management for American Petroleum Institute. "PHMSA Methane Detection Requirements Analysis." (Aug 16, 2023) at page 35. (PHMSA-2021-0039-26370).

[278] Lamb et al., "Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States," 49 Environmental Science & Technology 5161 (Mar. 31, 2015).

[279] Esroy, Daniel, "2019 Emission Factor Pilot Study" GTI project number 22509-3 (Aug. 21, 2020).

[280] Gao, B, et al. Study of methane migration in the shallow subsurface from a gas pipe leak. Elementa Science of the Anthropocene, 9: 1. DOI: https://doi.org/10.1525/ elementa.2021.00008 (July 2, 2021).

effective criterion than concentration, and that PHMSA should offer it as an alternative criterion for the standard. Both commenters said that flow rate, rather than concentration, would a better characterization of performance for the ALDP for safety and quantifying emissions.

Atmos Energy Corporation opposed an alternative ALDP standard, stating that PHMSA should complete a study for which technologies a flowrate standard would be appropriate. Encino Environmental Services urged PHMSA to express the detection limit in terms of mass emission rate at an associated probability of detection and wind speed. The Industry Trades opposed PHMSA using a single volumetric- or flow rate-based standard since not all instruments provide estimated leak rates, and they expressed a preference for flexibility. An individual commenter and Pennsylvania State Senator Katie Muth opposed the proposal to allow an alternative standard with notification to, and no objection from, PHMSA but did not provide further comment on that topic. The PST opposed the option for alternative performance standards.

The EDF, CSU/SMU, the NGA, and an operator discussed research on leak detection equipment performance. The EDF discussed research suggesting that methane emissions may be higher than previously thought on gas gathering lines[281] and gas distribution lines,[282] but that

[281] Yu et al., "Methane Emissions from Natural Gas Gathering Pipelines in the Permian Basin," Environ. Sci. Technol. Lett. (Nov. 8, 2022)

[282] Weller et al., "A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems," 54 Environmental Science & Technology 8958, 8966 (June 10, 2020).

additional research suggests that advanced monitoring methods and repair requirements can achieve significant reductions in emissions.[283]

A public commenter expressed concern regarding the 90-day notification and no-objection process and asked that PHMSA reconsider this process, stating that PHMSA should review and approve alternatives submitted rather than allowing operators to continue if they do not receive an objection from PHMSA in accordance with 49 CFR 192.18(c). The Industry Trades recommended that PHMSA build on the EPA's then-proposed approach[284] for approving alternatives at 40 CFR 60.5398b(d) to establish an approval procedure based on an operator demonstrating that they can achieve certain concentration or rate-based thresholds within the ALDP.

The PST stated that it would be arbitrary for PHMSA to allow gathering line operators to use alternatives to the ALDP standard, as gathering lines are prone to failure and contain noxious gas constituents. An individual commenter and Enstor Gas, LLC said PHMSA should consider reviewing alternative methods for the ALDP standard and state in the regulations those alternative methods it would accept to reduce the burden on both PHMSA and operators. An individual commenter urged PHMSA to express support for "high-quality measurements with certified measurements" versus subjective surveys using human senses.

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[283] Jiayang Wang et al., *Large-Scale Controlled Experiment Demonstrates Effectiveness of Methane Leak Detection and Repair Programs at Oil and Gas Facilities*, Environmental Science and Technology (2021); Arvind P. Ravikumar et al., Repeated leak detection and repair surveys reduce methane emissions over scale of years, 15 Env. Research Letters 034029 (2020), https://iopscience.iop.org/article/10.1088/1748-9326/ab6ae1/pdf.

[284] During the comment period for the NPRM associated with today's final rule, the EPA amendments described in section II.E of this document were also in the proposed rule stage. EPA's rules are now final. See 89 FR 16820.

Kairos Aerospace (now known as Insight M) suggested that PHMSA prioritize addressing "super emitters" by allowing operators to use aerial surveys as an alternative standard of performance for transmission pipelines in Class 1 and Class 2 locations. The commenter expressed concern that the ALDP in its current form would create unnecessary barriers to technology deployment, with the current approval process taxing PHMSA resources and slowing the adoption of new technology. Similarly, Bridger Photonics, Inc. urged PHMSA to allow operators to use remote sensing without auxiliary approval requirements and accept suitable EPA-approved alternative test methods for ALDP leak detection.

Several commenters provided comments supporting flow-rate alternatives to the concentration-based performance standards. Additionally, some stakeholders attending the 2021 Public Meeting commented that leak flow rate would be a more appropriate metric for leak detection and ALDP program performance than PHMSA's proposed concentration sensitivity metric.[285]

The Joint Environmental comment recommended flow-rate standards for mobile and aerial surveys and additionally recommended establishing different standards for different types of pipeline facilities due to the operational differences between gas distribution, transmission, and regulated gas gathering lines. They further recommended that PHMSA require operators to use handheld equipment with a minimum sensitivity of 5 ppm, consistent with the proposed performance standard for follow-up surveys of leak indications generated by mobile or aerial

[285] Written comments submitted before and after the meeting are available in the rulemaking docket at Doc. No. PHMSA-2021-0039.

surveys. They also provided the results from emissions modeling of different scenarios including the baseline, the NPRM, and their recommended proposal, using the FEAST model. The FEAST model allows probabilistic simulation of leak incidence, detection, and repair that can be used to evaluate the performance and costs of LDAR schemes.

Regarding gas distribution lines, the Joint Environmental comment stated that "emissions in the distribution system are dominated by many leaks on a smaller scale than [the] upstream system" and therefore require a relatively sensitive performance standard for leak detection. The commenters' modeling found that a leak rate criterion at or above 1 kg/hr resulted in increased emissions compared to a status quo that assumes widespread use of handheld leak detection equipment, even if the new repair rules are implemented. The commenters noted this was because careful leakage surveys using handheld equipment sensitive to 5 ppm are expected to be able to detect leaks smaller than 1 kg/hr. On the other hand, the commenters stated a more stringent sensitivity standard consistent with the performance of advanced mobile leak detection systems combining equipment with ppb sensitivity, GPS, and other inputs to generate a flow-rate measurement can detect more leaks than traditional survey methods and reduce emissions compared with baseline practice. Therefore, the Joint Environmental comment recommended that PHMSA require annual mobile screening surveys with equipment with a minimum detection limit of 0.5 kg/hr combined with operators performing a leak survey with handheld equipment at least once every 3 years as proposed in the NPRM.

For gas transmission and regulated gas gathering lines, the Joint Environmental comment recommended a lower sensitivity standard of 3 kg/hr for gas transmission lines and 10 kg/hr for regulated gas gathering lines, consistent with the performance of aerial surveillance technologies. The commenters noted that emissions for transmission and gas gathering systems are dominated by large-volume releases that are efficiently and effectively identified via aerial surveys, justifying a lower sensitivity standard. The commenters recommended a more conservative standard for gas transmission lines, closer to the minimum detection limit of aerial surveys to account for uncertainty regarding the characteristics of gas transmission leaks. They commented that the characteristics of leaks from gas transmission lines are less understood than those on distribution and gathering lines, which have been subjected to several relatively recent peer-reviewed studies using aerial or mobile survey technologies. Specifically, they commented that while gas gathering line emissions are known to be dominated by a small number of extremely large releases, suggesting that relatively low sensitivity is necessary to capture a significant portion of emissions, the distribution of emissions by leak size from gas transmission lines is less well established. If transmission line emissions are not as concentrated, then a higher sensitivity would be required to achieve significant emissions reductions.

The Industry Trades and Chevron recommended PHMSA adopt a 10 kg/hr performance standard as an alternative to the proposed concentration-based standard for remote sensing and other survey methods that measure flux rather than gas concentration. Chevron further noted that in the Yu Study[286] referenced in the NPRM preamble, all of the leaks detected via aerial surveys were above a 10 kg/hr flow rate, demonstrating that aerial surveys with a 10 kg/hr detection limit

[286] Yu et al., "Methane Emissions from Natural Gas Gathering Pipelines in the Permian Basin," Environ. Sci. Technol. Lett. (Nov. 8, 2022)

would be an effective performance target for gas gathering lines. In the Industry Trades recommendation, this 10 kg/hr flow rate standard would apply to all facilities required to perform leak surveys in part 192. A comment from multiple gas gathering industry trade associations included a report prepared by Highwood for API that compared the benefits from reduced emissions and costs of the baseline leak survey requirements, the proposed requirements in the NPRM, and flow rate alternatives of 1, 4, 10, and 30 kg/hr using modeling with LDAR-Sim,[287] another LDAR program modeling tool similar to the FEAST model referenced above. Based on this modeling, Highwood found that while the proposed standard in the NPRM resulted in the highest emissions reduction, it required an "excessively high number of repairs" of very small leaks that drive cost. The extent to which the repair of these small leaks affects the benefits calculation depends on the assumed distribution of leak volumes; for leak populations prone to large leaks, the difference in emissions reductions between the proposal and the least sensitive 30-kg standard that Highwood examined was approximately 6.1 percent, while for leak populations prone to medium-sized leaks, the 30-kg standard resulted in 73 percent lower emissions abatement. In either case, the Highwood model of the NPRM resulted in significantly more leak repairs than the alternatives the report considered. Similarly, Highwood found in their modeling that increasing the survey frequency to twice each year instead of once each year resulted in increased survey costs but relatively small increases in emissions abatement.

[287] Highwood Emissions Management for American Petroleum Institute. "PHMSA Methane Detection Requirements Analysis". (Aug 16, 2023). (PHMSA-2021-0039-26370).

Kairos Aerospace[288] commented that a detection limit between 10 and 50 kg/hr could achieve similar emissions reductions for gas gathering lines compared with precise ground surveys with a detection limit below 0.1 kg/hr, noting that since emissions from gas gathering pipeline facilities are highly dominated by very large releases, a lower sensitivity standard does not result in a significant decrease in the total emissions detected. Kairos Aerospace further noted that a standard that accommodates cost-effective aerial surveys can result in greater emissions reductions when combined with more frequent surveys because the largest releases are detected, and therefore repaired, sooner. Kairos Aerospace also provided a table of the results of an analysis they performed in LDAR-Sim based on parameters derived from their own surveys of gas gathering lines in the Permian basin and another study using ground-based measurement in the Fayetteville basin. Their analysis found that detection limits between 10 and 50 kg/hr reduced total emissions by between 32 to 33 percent compared with 35 percent of emissions for a ground-based ALDP that was conservatively assumed to detect all leaks, and that performing more frequent surveys could result in dramatically greater emissions reductions. They concluded that more frequent surveys, which are more feasible with performance standards that accommodate aerial survey technologies, result in greater emissions reductions at lower cost by reducing the costs of surveys and focusing repairs on the largest releases.

Bridger Photonics, another aerial survey provider, recommended a separate performance standard of 4.0 kg/hr with a 90 percent probability of detection for gas transmission and gas gathering lines but with exceptions or delays provided for leaks less than 10 kg/hr in rural areas.

[288] Kairos Aerospace. August 16, 2023. (PHMSA-2021-0039-24690),

In their comment, they provided information from their own survey results showing that emissions sources greater than 4.0 kg/hr represented 97 percent of cumulative emissions in one production basin and 95 percent of cumulative emissions in another. The commenter noted that while transmission lines generally have fewer leaks than gas gathering lines, a 4 kg/hr detection limit "would also be sufficient for the transmission sector."

The Clean Hydrogen Future Coalition recommended that "PHMSA modify proposed § 192.763(c) so that it is flexible enough to meaningfully accommodate new, innovative and effective leak detection technologies that may be developed in the future for unblended hydrogen pipelines." Air Liquide Large Industries U.S. L.P. said there are no commercially available leak detection devices that can reliably detect hydrogen at the 5-ppm level. Clean Hydrogen Future Coalition recommended that PHMSA defer applying the standard to unblended hydrogen pipelines because the proposed standard is not technically feasible, reasonable, or cost-effective for pipelines transporting unblended hydrogen. Additionally, the commenter stated that PHMSA did not explain in the NPRM why the proposed standard would be workable for unblended hydrogen pipelines, nor did PHMSA analyze in the PRIA the costs and benefits of applying the proposed standard to such pipelines.

The Joint Environmental comment raised concerns about the safety and environmental impact of hydrogen pipelines and recommended that PHMSA consider hydrogen pipeline safety regulations holistically in a future rulemaking to address these issues. In the interim, the commenters recommended that PHMSA require all hydrogen operators to propose an alternative

ALDP performance standard in accordance with § 192.18 since leak detection technologies for hydrogen are currently less advanced than those for natural gas.

The GPAC completed its deliberations concerning the ALDP performance standard during the November 2023 GPAC meeting. Several commenters provided comments on the GPAC deliberations with respect to the ALDP performance standard in public comments, the majority of which were submitted after the January 5, 2024, deadline for comments on the proceedings of the November 2023 GPAC Meeting.

In supplemental comments submitted after the April 2024 GPAC meeting, the AGA, API, AFPM, APGA, GPA Midstream, INGAA, and the NGA, jointly filed comments that included commentary on the GPAC recommendations with respect to the ALDP performance standard. These comments reiterated previous comments these stakeholders made requesting PHMSA to simplify the program performance standard into a sensitivity standard for equipment and clarify that validation of equipment performance may be performed by the equipment manufacturer. Regarding the GPAC recommendation to consider alternative performance standards for pipelines inside of buildings, the commenters recommended a standard of 500 ppm for handheld equipment or continuous monitoring sensors, allowing soap tests, and allowing the use of OGI meeting EPA standards at appendix K to 40 CFR 60. They reiterated previous comments that 500 ppm was more consistent with the capabilities of combustible gas indicators (CGI) used for inside leak surveys and industry standards for residential methane detectors.[289] Unlike the GPAC recommendation, they requested that PHMSA allow the use of OGI for gas

[289] For example, NFPA 715, Underwriters Laboratories (UL) 1484, and UL 2075.

distribution lines in addition to gas transmission lines and regulated gas gathering lines. Finally, they recommended a leak rate standard for gas distribution line screening surveys of 0.2 kg/hr instead of 0.5 kg/hr recommended by the GPAC for consistency with the grade 2 leak criteria. They commented that the revised standard ensures reliable detection of grade 2 leaks without the need for supplemental surveys with handheld equipment or other means.

3. GPAC Deliberation Summary

The GPAC was briefed on and deliberated the NPRM with respect to the ALDP performance standard on November 28 and 29, 2023,

Following a briefing by PHMSA staff, the GPAC provided an opportunity for statements from members of the audience. Persons representing gas transmission and gas distribution, and LNG operators; gas transmission, distribution, LNG, and gas gathering trade associations; and technology providers provided statements for the record. Broadly, comments from both pipeline operators and leak detection equipment providers were primarily opposed to establishing a single concentration-based standard to all types of pipeline facilities and all types of survey methods.

The most common suggestion from both operators and leak detection technology providers was to adopt a flow-rate standard for aerial surveys, continuous monitoring, and other screening surveys. Commenters mentioned that an overly sensitive standard or one defined only by gas concentration (i.e., ppm) would exclude such methods, and that a stringent sensitivity standard was not necessary to identify the largest releases that account for most emissions based on observations from studies employing aerial surveys. Several commenters also noted that appropriate leak-rate standards would be consistent with methane emission monitoring requirements proposed by the EPA in 40 CFR 60 subparts OOOOb and OOOOc. As described in section II.E. of this final rule, these leak rate standards were ultimately adopted in the 2024 New Source Performance Standard and Emissions Guidelines final rule.[290] A representative from an aerial surveying firm commented that in their experience, a 4 kg/hr standard covers 95 to 97 percent of total emissions, a 10 kg/hr standard covers 86 percent of measured emissions, and a 15 kg/hr standard would cover 70 percent of emissions. Representatives of distribution operators and a leak detection equipment manufacturer commented that surveys of pipelines located indoors should similarly be subject to a different standard due to the equipment that is used and the fact that operators have direct access to the facility. These commenters generally recommended a 1 percent LEL standard for leak detection equipment used inside of buildings consistent with the performance of CGIs, semiconductor gas detectors, and certain continuous monitoring systems used in New York. Commenters from pipeline trade associations reiterated recommendations from their written comments synthesizing these comments and generally recommended 10 kg/hr or 500 ppm standard for screening surveys, 5 ppm for handheld equipment, and 500 ppm for surveys inside of buildings. Many of these commenters noted failing to accommodate the range of technologies commonly and effectively used in these circumstances described above with FIDs or other more sensitive devices would incur significant costs associated with purchasing equipment, modifying procedures, and retraining personnel with little to no offsetting benefits.

[290] 89 FR 16820 (Mar 8, 2024).

GPAC discussion of the ALDP requirements began on November 29, 2023, starting with a discussion of guiding principles and then a discussion of the performance standard for gas transmission pipelines. The discussion of principles generally reflected the concerns raised by public comments and reflected in the text of the vote described in section III.D.4 below. Members quickly reached consensus on the general principal that adopting a leak-rate performance standard for mobile aerial, or satellite screening surveys with a 90 percent probability of detection was appropriate in order to accommodate commercially available advanced technology and for alignment with proposed EPA emissions monitoring standards. However, some cautioned that traditional walking or mobile surveys performed with concentration-based equipment should still be permitted as an alternative, particularly for both gas transmission and distribution lines operated by local distribution companies. Members agreed that such screening surveys would trigger follow-up investigation of leak indications with handheld equipment. However, members debated whether a screening survey should supplement a comprehensive survey with handheld equipment or be accepted as a standalone survey method—ultimately the committee recommendations did not adopt proposals from a member representing the public to require both screening surveys and traditional surveys with handheld equipment.

Several members of the Committee discussion emphasized a preference for technology-neutral standards that can accommodate emerging technologies. Members, particularly those representing pipeline operators, cautioned against setting overly restrictive standards that screened out potentially efficient and effective emerging technologies, resulted in excessive false positives, or that would identify very small leaks for costly and potentially environmentally damaging repair. Members representing pipeline operators were especially interested in establishing standards achievable by aerial, satellite, or continuous monitoring leak detection methods and opposed recommendations to require certain survey methods, such as mobile surveys. Conversely, members representing the public emphasized the need for an adopted standard to reflect the state of modern leak detection equipment and reliably detect significant emissions, and one member cautioned that a standard achievable by existing satellite technology was unlikely to detect a significant share of emissions any class of pipeline facility. Ultimately, the Committee members reached agreement that it was appropriate to establish technology-neutral performance standards that include a flow-rate standard, or equivalent methods that can be validated to detect a certain flow rate, as an alternative to a sensitivity-based standard for traditional survey methods. Members also emphasized alignment with the EPA's methane emissions monitoring standards at 40 CFR 60 subparts OOOOa through OOOOc), particularly with respect to permitting screening surveys with a flow-rate standard at a 90 percent probability of detection, allowing OGI for aboveground facilities.

The GPAC also discussed the procedures proposed in § 192.763(c) regarding operators requesting an alternative performance standard. Members representing the public raised concerns about the no-objection process in § 192.18, which allows an operator to proceed with their proposed alternative method if they do not receive notice of objection from PHMSA within 90 days, since it could allow operators to use ineffective technology if PHMSA does not complete its review. Members representing the public also raised concerns regarding the lack of public availability of information related to requests and approvals for alternative methods under that process. On the other hand, members representing pipeline operators commented that their support for recommendations for quantitative standards was contingent on allowing an alternative process to accommodate emerging technologies. Industry members were particularly concerned that advanced technologies may measure concentration in ppm rather than leak rate in kg/hr but could be capable of reliably detecting leaks meeting a prescribed leak rate standard, and that they should be permitted under this framework. A member representing the public explained that the leakage rate standard can accommodate this concern, since methods using ppm sensors or other types of sensors could be validated to meet a leakage rate standard through testing even if it does not itself directly measure leakage rate. Similarly, members representing operators opposed limiting the alternative performance standard to gas transmission or gathering lines in Class 1 and 2 locations.

Considering the concerns above, members debated specific performance standards for gas transmission lines. Members discussed separate performance standards for flow-rate criteria for screening surveys with follow up-investigations, concentration standards for traditional walking and mobile surveys, and standards for aboveground appurtenances. For screening surveys, members expressed interest in establishing a standard that was consistent with the performance of aerial, satellite, and continuous monitoring methods but effective at identifying a significant portion of emissions. A member representing the public recommended a performance standard of 3 kg/hr for gas transmission lines and 10 kg/hr for gas gathering lines. They explained that they favored a more conservative standard for gas transmission lines compared with gas gathering lines that reflects the greater uncertainty of emissions from gas transmission lines compared with gas gathering lines, which have been more extensively studied in aerial surveying studies by researchers. On the other hand, members representing transmission and gathering line operators suggested 10 kg/hr for all such facilities. Members representing operators disagreed that the uncertainty justified a more stringent standard, and that in their experience, leaks from transmission line pipe were rare compared with leaks from valves, flanges, and other aboveground appurtenances that are typically surveyed by other means such as OGI. As noted above, members representing the industry were concerned about setting a standard that would target small leaks or preclude the use of some continuous monitoring or future space-based satellite detection methods. Members also described a tradeoff between higher equipment sensitivity and the number of false positives. After deliberating, committee members ultimately agreed unanimously on a 10 kg/hr standard for screening surveys of both gas transmission and regulated gas gathering lines, subject to additional discussion on the applicability to Type C lines (see section III.P below). For investigations of leak indications following a screening survey, members debated whether it was necessary to prescribe performance requirements for handheld equipment but ultimately came to consensus that some standard was required. In addition to the 5-ppm standard for equipment in the NPRM, members recommended adding standards of 5 ppm-m to accommodate open-path detectors and 1 percent LEL to accommodate CGIs. As noted above, members agreed it was important to include standards for traditional surveys, and recommended a concentration sensitivity standard of 5 ppm or 5 ppm-m. Finally, the recommendation the Committee made for gas transmission pipelines incorporated the results of the discussion regarding the alternative performance standard described in the general discussion above.

For gas distribution lines, a member proposed vote language identical to the gas transmission line recommendation but with a screening survey with a leak-rate performance standard of 0.5 kg/hr complementing a traditional survey with handheld or mobile equipment. This member referenced a study finding that traditional survey methods found only 35 percent of the leaks identified by advanced mobile leak detection systems but also that mobile surveys may miss some leaks identified in traditional walking surveys. During the discussion, they recommended considering an exception for smaller operators of less than 250,000 service lines, which is consistent with a threshold established at § 192.631, from the mobile survey requirement and recommended that PHMSA consider the public comments regarding an alternative performance standard for leak detection equipment used inside of buildings. Other members representing operators strongly opposed the requirement for operators to perform two surveys, since it increased the survey frequency beyond what was discussed previously (see section III.A), prescribed specific survey methods or technologies, would be impracticable for smaller operators, and was based on studies supporting the reliability of mobile screening surveys as a standalone survey method. Members representing State agencies were also concerned with requiring a mobile survey, noting that portions of a pipeline facility may not be accessible to such methods, such as longer service lines in suburban areas. A member representing industry suggested a standard of 3 kg/hr rather than 0.5 kg/hr, but the committee discussion coalesced around a 0.5 kg/hr threshold after another member representing the public described literature from three studies of thousands of leaks finding that the largest leaks identified were measured at up to 1.9 kg/hr. A member representing the public observed that "10 SCF [per hour] is considered a large emitter in the distribution system," corresponding to approximately 0.2 kg/hr. After considerable discussion, the committee ultimately recommended allowing a screening survey with a 0.5 kg/hr performance standard as a standalone leak survey method, rather than requiring a mobile survey for larger operators. Committee members, reiterating concerns raised by operators during the public comment period, discussed whether alternative standards were appropriate for pipelines located inside of building.

4. GPAC Recommendation

The GPAC held five separate votes concerning ALDP requirements, three of which addressed recommendations regarding the minimum equipment sensitivity performance standard and the program-wide performance standard. Two of those votes addressed program requirements and are discussed in section III.E. below. As described in the deliberation summary in section III.D.3, the GPAC discussions and recommendations to PHMSA on the ALDP performance standards exhibited a desire for technology-neutral performance standards; performance standards tailored to different types of pipeline facilities, survey methods, and operating environments; alignment with EPA methane emissions monitoring standards; and flexibility via an alternative performance standard, so long as that process is subject to public transparency and efficient and effective oversight from PHMSA. The GPAC recommendations also reflected consensus that alternative standards were appropriate for pipelines located aboveground or inside of buildings, particularly for distribution service lines inside of buildings.

First, the GPAC recommended in a 14 – 1 vote that PHMSA consider the principles raised in the proceedings of the GPAC when developing the final ALDP technology standards, "including a risk-based approach, the need to develop standards, the need to ensure that such standards are technology neutral and incorporate a flow-rate alternative, encourage technology innovation, allow flexibility for operators to choose technologies to meet the proposed standards and alternative performance standard, recognize supply chain issues, address operator-specific needs, and maintain alignment with EPA standards."

Second, the GPAC voted unanimously to recommend that PHMSA the following performance standards for gas transmission and regulated gas gathering lines:

- 10 kg/hr flow rate standard for screening surveys and a follow up investigation of leak indications with handheld equipment (with thresholds of 5 ppm, 5 ppm-m, or 1 percent LEL) to pinpoint the source of the leak, or a leak survey with handheld or mobile equipment (5 ppm, or ppm-m thresholds).
- A recommended probability of detection standard for all flow-rate-based advanced leak detection technology of 90 percent.
- Aboveground appurtenances: OGI (consistent with the EPA).
- Clarify that the scope of the alternative performance standard process in §§ 192.18 and 192.763(c) covers all gas transmission and regulated gas gathering pipelines.
- PHMSA should provide meaningful and timely review of notifications and should work with stakeholders to address public availability of notifications.

Third, the GPAC recommended in a 14 – 1 vote the following ALDP performance standards for gas distribution lines:

- 0.5 kg/hr screening survey and follow-up investigation of leak indications with handheld equipment (5 ppm, 5 ppm-m, or 1 percent LEL thresholds), or a leak survey with handheld or mobile equipment (5 ppm or 5 ppm-m thresholds).
- Consideration of an alternative standard for inside piping.
- A recommended probability of detection standard for all flow-rate-based advanced leak detection technology of 90 percent.
- Clarify that the scope of the alternative performance standard process in §§ 192.18 and 192.763(c) covers gas distribution pipelines.
- PHMSA should provide meaningful and timely review of notifications and should work with stakeholders to address public availability of notifications.

These recommended distribution pipeline performance standards are similar to the recommendations for transmission and regulated gathering pipelines, with the notable exceptions of a lower minimum sensitivity threshold for flow rate-based equipment used in distribution screening surveys, express direction for PHMSA to consider tailored requirements for indoor piping on distribution lines, and express direction for PHMSA to consider permitting use of OGI on aboveground appurtenances for transmission and gathering lines only.

5. PHMSA Response

General

Public comments and the GPAC recommendations both raised concerns with the proposed performance standard for leak detection equipment and suggested adopting a leak rate-based alternative to the proposed concentration standard that is technology-neutral and addresses substantive differences between gas distribution, gas transmission, and regulated gas gathering lines. This final rule addresses these issues by adopting a leakage-rate standard defined in kilograms per hour at a 90 percent probability of detection as an alternative to the concentration-based equipment sensitivity standard that was proposed. The leak rate standard is consistent with a similar emissions monitoring standard established by the EPA and was supported by the GPAC and public comments. In this final rule, an operator can select from an equipment sensitivity standard for surveys with handheld and certain mobile equipment, a leak-rate standard in kg/hr for screening surveys, or other standards that apply in specific circumstances, such as surveys of pipelines located aboveground or inside of buildings. Adopting these different options rather than prescribing one standard better reflects the diversity of facilities, operating environments, and commercially available detection methods that are affected by this rule.

The leak-rate criteria applicable to each type of pipeline is described below under the requirements specific to those pipelines. Consistent with the GPAC recommendation and public comments, the applicable performance standards for ALDPs on gas distribution systems and gas transmission and regulated gas gathering systems are different, reflecting the differences between the observed characteristics of leaks on gas distribution pipelines compared to the characteristics of leaks on gas transmission lines. Finally, PHMSA has included alternative performance standards for leak surveys of pipelines inside of buildings that address the GPAC recommendations to better reflect differences in operating environments and equipment for such facilities compared to buried pipelines.

Simplifying the concentration standard and providing a flow-rate alternative performance standard for screening surveys addresses many of the issues raised by commenters regarding the practicability of achieving, validating, and replicating the proposed detection threshold. The revised screening survey standard encourages the use of cost-effective, commercially available screening survey methods, particularly mobile, aerial, and satellite survey methods that can detect larger releases that dominate the total emissions from such systems at a relatively lower cost.

An operator may supplement devices that meet the various sensitivity standard with other, potentially less-sensitive equipment, such as most CGIs, either as part of the leak survey itself and during activities such as leak investigations and grading.

In the final RIA, PHMSA estimated that, consistent with the probability of detection standard adopted for flow rate standards, leakage surveys meeting the performance standard would be capable of detecting 90% of targeted leaks, in comparison traditional leakage surveys performed without the enhancements adopted in the final rule are assumed to detect 85% as many leaks compared to the final rule (or 76.5% of targeted leaks). The increased effectiveness of ALDP standards results in increased costs due to higher survey unit costs and more frequent identification and remediation of leaks, but also results in higher benefits from eliminating the additional leaks found. PHMSA also performed sensitivity analysis assuming a greater difference between baseline and revised leak detection practices that assumes that baseline practices detect 50% of leaks detectible by the revised standard; that scenario results increased costs and benefits from repairs of additional leaks, but remains net beneficial for each facility type covered by the ALDP standards. In addition to the sensitivity analyses, section 2.2.1.12 describes an alternative where PHMSA adopts only a concentration-based equipment sensitivity standard, similar to the 5-ppm standard proposed in the NPRM, or conversely required the use of screening surveys meeting the flow rate standard, as suggested by some public comments. PHMSA found that either of these alternatives would not provide additional benefits to safety and the environment, and therefore needlessly restrict operator flexibility. Additionally, to the extent that operators use different equipment and methods, restricting survey methods results in costs associated with replacement of leak detection equipment with little to no corresponding benefits.

Flow-rate-based alternative performance standard for screening surveys

PHMSA agrees with the public comments and the GPAC recommendation on the merits of establishing a leak-rate alternative to the proposed concentration-based standard for handheld equipment for remote sensing, continuous monitoring, and mobile, aerial, and satellite screening surveys. PHMSA agrees that since the intended outcome of the LDAR program is minimizing the amount of natural and other gas emissions, adopting a performance standard defined by an number of emissions is appropriate. Therefore, after considering the comments and the recommendations of the GPAC, this final rule establishes leak-rate performance standards, defined in kg/hr, as an alternative to the concentration-based standard applicable to surveys using handheld equipment and certain other circumstances. As recommended by public comments, this leak-rate standard established in this final rule applies to screening surveys using infrared or laser-based leak detection equipment; mobile, aerial, or satellite-based platforms; or fixed, continuous monitoring sensors. This change addresses comments from a wide range of stakeholders supporting a leak-rate standard and standards compatible with aerial survey methodologies for gas transmission lines without additional approval required through the mechanisms of § 192.18. The standards finalized in this rule also address concerns that the proposed performance standard for leak detection equipment was beyond the capability of aerial and drone surveys, which are commonly used for surveys of gas transmission and regulated gas gathering lines.

For screening surveys on gas transmission and regulated gas gathering lines, this final rule promulgates a performance standard of 10 kg/hr for leak detection equipment, while for gas distribution lines, PHMSA is establishing the performance standard at 0.2 kg/hr for leak detection equipment. These standards help ensure operators eliminate most emissions from gas pipeline leaks and were recommended by the GPAC and supported by public comments. These detection standards are based on a 90 percent probability of detection, consistent with the requirements the EPA established for a "Alternative Technology Periodic Screening Frequency" and as recommended by the GPAC and supported by public comments. Additionally, the performance standard for gas transmission pipelines is consistent with standards adopted by the EPA for fugitive emissions monitoring of compressor stations in 40 CFR 60 OOOOa through

OOOOb. The leak-rate standards are addressed in greater detail in the transmission/gathering and distribution discussions later in this document.

Recognizing the principles recommended by the GPAC and public comments recommending PHMSA reconcile the leak detection equipment performance standards with those established by the EPA in March 2024, for the purposes of this final rule, an operator can demonstrate compliance with the leak-rate equipment performance standard if their survey technology and method is approved by the EPA for the types of facilities being surveyed and meets the minimum detection threshold and survey frequency in 49 CFR part 192 applicable to the pipeline facility. For example, for gas transmission pipelines, documentation that a survey method is approved by the EPA for any of the detection thresholds of 10 kg/hr or less in Table 1 to Subpart OOOOb of part 60 would provide evidence of meeting the performance standard at 49 CFR 192.763. For gas distribution pipelines, The EPA does not require emissions monitoring for gas distribution pipelines, nor does Table 1 to subpart OOOOb of part 60 include a 0.2 kg/hr performance standard option. Therefore, PHMSA's rules applicable to distribution lines are not in conflict with any methane emissions monitoring standards adopted by the EPA. This consideration would only cover facilities regulated by the EPA or equivalent facilities, and that the EPA emissions monitoring requirements do not cover buried pipeline facilities in general.

Several commenters discussed flow-rate standards in conjunction with increased survey frequencies. The frequencies of leak surveys are described in this document in section III.A for gas distribution pipeline facilities, III.B for gas transmission and gas gathering pipeline facilities, III.C for LNG pipeline facilities, and III.P for regulated gas gathering pipeline facilities.

Concentration sensitivity standard for handheld and certain mobile surveys.

With the addition of a leak-rate performance standard for leak detection equipment as an alternative, this final rule retains a simpler concentration sensitivity standard requiring leak detection equipment used for most leak surveys with handheld equipment and certain mobile surveys have a minimum sensitivity of 5 ppm. As described in greater detail below, other standards may apply to leak detection equipment used for leak surveys of gas pipelines that are located aboveground or inside of buildings. In this final rule, this standard omits the 5-ft distance condition proposed in the NPRM. The 5-ppm-within-5-feet standard was intended to reflect a leak volume (i.e., leak rate) that can be detected by handheld equipment, such as FIDs, which typically measure gas concentration rather than leak rate. Since the concentration sensitivity standard is now an alternative to, rather than a proxy for, a leak flow rate standard, the distance portion of the criteria is no longer necessary. This change simplifies compliance for operators that choose to use the handheld equipment sensitivity standard by removing the distance requirement proposed in the NPRM.

When proposing its leak equipment detection performance standard in the NPRM, PHMSA did not intend to preclude operators using technologies such as laser-based detectors that do not output point measurements. Therefore, this final rule adopts a 5 ppm-m path-integrated concentration[291] sensitivity standard for infrared- and laser-based gas detectors as

[291] Compared with a typical point sensor such as a FID, which measures the concentration of gas in a particular point in space, open-path gas detectors (e.g., laser or infrared beam-based detectors) measure total gas concentration in a beam in front of the device. This measurement is expressed as ppm-m or the sum total of gas concentration (ppm) in each meter along the detection range of the device.

recommended by the GPAC. In other words, open-path devices with a minimum sensitivity of 5 ppm-m and point detectors with a minimum sensitivity of 5 ppm are both permitted under the standard of this final rule. Providing the concentration-based alternative in this final rule addresses concerns from gas distribution trade associations that solely relying on a leak-rate criterion within the ALDP provisions would exclude large stocks of existing leak detection equipment that use concentration measurements. Limiting the 5 ppm-m sensitivity standard to handheld and ground-based equipment and adopting a flow-rate alternative performance standard for screening surveys addresses concerns from aerial survey providers on the appropriateness, consistency, and effectiveness of only adopting a ppm-m detection criterion.

As described in section IV.B.1 of the NPRM, these point concentration and path-integrated concentration standards in this final rule correspond to the claimed sensitivity of commercially available, open-path gas detectors commonly used to conduct gas pipeline leak surveys. As described in greater later in this section, PHMSA has also adopted lower sensitivity requirements for leak detection equipment used for aboveground and indoor facilities that will ensure even greater flexibility in tool section. On top of reducing the likelihood that an operator will have to procure different equipment, the significantly increased compliance timeline described in section III.U. provides additional time for operator to evaluate, procedure, and train personnel on new equipment should such a change be necessary. PHMSA also notes that gas detectors such as FIDs and CGIs used for detecting methane are often also effective for the detection of various types of hydrocarbon fuels such as LPG, and that handheld gas detectors are commercially available for other organic compounds and toxic gases such as chlorine, hydrogen chloride, and carbon monoxide. The NPRM described the performance and advantages of open-path gas detectors in the broader discussion of commercially available advanced leak detection technologies, and PHMSA did not intend to restrict their use by omitting a separate standard for such devices defined in ppm-m. Defining a ppm-m standard for such devices clarifies that they are approved for use during leak surveys, provided the leak survey procedure is capable of reliably detecting leaks within the defined operational and environmental parameters.

Removing the 5-feet-distance condition significantly simplifies the performance standard for leak detection equipment. When using portable leak detection equipment an operator is only required to use leak detection equipment that meets the minimum sensitivity standard for leak detection equipment. Eliminating the distance condition addresses commenter concerns about the difficulty of demonstrating compliance considering changes in wind, soil, and other environmental factors. Additionally, while PHMSA did not intend to require operators to locate pipelines prior to performing all leak surveys, unless necessary to achieve the performance standard for the leak detection equipment, this change eliminates this potential interpretation.

The GPAC further recommended that PHMSA allow operators to use an equipment sensitivity standard of 5 ppm or 5 ppm-m as an alternative to the new leak-rate sensitivity standard for "mobile equipment." This final rule adopts this recommendation with some restrictions to help ensure that operators perform mobile surveys using the equipment-sensitivity standard rather than the leak-rate standard in situations where such surveys are more likely to be reliable. In this final rule, PHMSA has interpreted the term "mobile equipment" from the GPAC recommendation to refer to leak survey equipment mounted on ground vehicles. PHMSA understands the primary purpose of the GPAC's recommendation to allow a concentration-based standard for mobile equipment was to allow the practice of surveying gas distribution mains under streets with vehicles equipped with concentration-based gas sensors. Similarly, PHMSA is also aware of operators using gas detectors mounted on off-road passenger vehicles and all-terrain vehicles for leak surveys of gas transmission and gathering lines. Compared to the advanced mobile leak detection systems described in section II.D.4 of the NPRM that identify and quantify leak indications from measuring gas plumes, these traditional survey methods using mobile equipment take concentration readings at the probable site of leakage. This is similar to a walking survey but with equipment mounted on a vehicle. These methods generally do not involve release rate quantification.

As described in section III.E, the requirements for performing leak surveys pursuant to § 192.763(a)(2)(i) provide additional specificity regarding the leak survey procedures an operator must have and carry out, including the requirement for an operator to define environmental and operational conditions when performing leak surveys. Defined requirements for the equipment's effective range and dwell time[292] necessary to achieve a stable reading are the most relevant of these conditions for traditional mobile survey methods. As noted in public comments from CSU/SMU, the reliability of detection with point sensors decreases significantly with increased distance from the emissions source. Additionally, as several commenters noted, different devices

[292] Dwell time refers to the minimum amount of time a gas detector must be placed at a probable emissions source to achieve a reliable, stable reading.

require a different dwell time. Both factors have implications for performing traditional mobile surveys with point sensors.

For ground-based, traditional mobile surveys, these considerations generally require such surveys be performed directly over the pipeline facility being surveyed, with the intakes for gas sampling equipment located as near as practicable to the ground. This is generally most viable for leak surveys of gas distribution mains under roads and some gas transmission lines accessible to ground vehicles. Surveys using open-path infrared- or laser-based detectors must be performed within the effective range of the device. In either case, the response time of the device will directly impact the maximum survey speed, and operator procedures must define a maximum survey speed that ensures the reliable detection of leaks, considering the response rate and other capabilities of the leak detection equipment being used. These procedural considerations are addressed in the discussion of ALDP program elements in section III.E. Generally, mobile surveys that use a point sensor to take in-plume measurements at greater distances may still be used for leak surveys but must meet the leak-rate criteria applicable to the pipeline being surveyed instead of the sensitivity standard described here. This concentration sensitivity standard may not be used for aerial and satellite-based survey methods; however, operators may use aerial or satellite-based survey methods via the leak-rate criteria for the pipeline being surveyed.

In response to public comments and the GPAC recommendation to consider an alternative standard for gas distribution pipelines inside of buildings, PHMSA is providing in this final rule an alternative minimum equipment sensitivity standard of 500 ppm, equivalent to 1 percent LEL of methane gas, for leak surveys or continuous monitoring sensors inside of buildings. This standard is described in greater detail in the discussion of leak surveys inside of buildings and for aboveground pipeline facilities.

While some commenters supported the 5 ppm or 5 ppm-m standard, others suggested different standards for a concentration-based metric that were typically less sensitive. The most common concern given by commenters was that leak definition for methane fugitive emissions monitoring in EPA's OOOOa-OOOOc is defined at 500 ppm[293] (approximately 1 percent LEL for methane gas) when using a FID or other handheld equipment in accordance with EPA Method 21.[294] The EPA methane emissions monitoring requirements are applicable to aboveground equipment, and EPA Method 21 is based on direct access to the fugitive emissions components being monitored with the inlet of a leak detection device placed as close as practicable to the leaking component. For example, the EPA guidance document, "Leak Detection and Repair: A Best Practices Guide," highlights a study from the Bay Area Air Quality Management District[295] that found that measurements 1 cm or more from the leaking component interface significantly degrades the probability of detecting leaks above 500 ppm.[296] EPA Method 21 explicitly requires placing the probe inlet of a leak detection device within 1 cm of the shaft-seal interface. For buried pipelines, direct sub-cm access to every potential leak source

[293] See, for example, emissions monitoring requirements at 40 CFR 60.5397a(c)(8) and 40 CFR 60.5397b(c)(8).
[294] EPA Method 21 of Appendix A-7 of 40 CFR part 60.
[295] Kino et al, Bay Area Air Quality Management District. "Draft Staff Report: Regulation 8, Rule 18: Equipment Leaks" (Jun. 1997). Available in the docket.
[296] EPA Office of Compliance. "Leak Detection and Repair: A Best Practices Guide," Page 17. https://www.epa.gov/compliance/leak-detection-and-repair-best-practices-guide. (October 2007).

is not possible, therefore the NPRM considered the use of more sensitive equipment measuring leaks at greater distances compared with what is typical for the EPA's emissions monitoring surveys of aboveground equipment using EPA Method 21. To the extent that a high sensitivity may over-identify leaks, changes to the repair requirements in § 192.760 of this final rule reduce the impact that high detection sensitivity has on the costs and environmental impacts of leak repairs. Specifically, this final rule adopts longer repair timelines for grade 2 and grade 3 leaks in § 192.760 to reduce the cost and environmental impacts of repairs by giving operators more opportunity to bundle repair projects together. Additionally, this final rule includes an exception from repair requirements for leaks with very low emission rates. Together, these changes result in fewer outages and blowdowns for maintenance activities. These changes are described in greater detail in section III.I.

PHMSA disagrees with the comments suggesting that handheld equipment that can meet the 5 ppm, 5 ppm-m, or 1 percent LEL criteria is not commercially available. A wide range of commercially available FIDs, IR, and semiconductor detectors can achieve a 5-ppm detection rate, and a 5 ppm-m rate is attainable with mainstream handheld open-path devices. The change in this final rule allowing devices with a 1 percent LEL detection rate (500 ppm for natural gas) inside of buildings expands the available tools for those leak surveys and investigations. While certain remote, aerial, and mobile survey methods may not currently be able to achieve the proposed performance standard for leak detection equipment, the adoption of the GPAC-recommended values for leak-rate performance standards for leak detection equipment address the concerns commenters raised with those methods. In response to comments concerned that the proposed sensitivity standard was unattainable by aerial surveys and other screening surveys, PHMSA has, consistent with the GPAC recommendation, adopted separate, flow-rate-based standards for such methods. Similarly, PHMSA recognizes potential circumstances where the use of less-sensitive equipment is potentially justified, particularly for leak surveys and investigations of aboveground equipment and pipelines inside buildings. These changes are described in greater detail in the larger discussion of the flow-rate based alternative above and in the discussion of leak detection equipment requirements for surveys of aboveground and indoor piping described below.

Regarding the comments suggesting inconsistency with measurements in LEL, PHMSA disagrees that the proposed concentration standards in ppm and ppm-m are incompatible with leak grading designated by percentage of LEL. Measurements in ppm can be converted to percent gas in the atmosphere and therefore to a percentage LEL for the gas being surveyed. PHMSA acknowledges that measurements in ppm-m do not measure a point concentration and therefore are not directly convertible. However, an operator may supplement an initial or pinpointing survey performed with an open-path device with another device, such as an FID or CGI, to establish the grade of the leak.

One technology provider recommended a lower detection limit of 1 ppm for handheld leak detection equipment. PHMSA has concerns that a lower detection limit for handheld equipment is greater than what is required to detect even very small leaks, and a 1 ppm detection limit significantly reduces the choices of commercially available leak detection equipment to a smaller number of IR devices and some FIDs. A 1 ppm or 1 ppm-m detection limit would also preclude the use of CGIs for surveys of indoor piping and the use of many mainstream handheld open-path gas detectors.

Several commenters discussed concerns with the response time[297] of equipment and how it affects the required dwell time during a leak survey. Some of these comments, particularly from equipment manufacturers, suggested that PHMSA prescribe minimum response times as part of the ALDP performance standard for leak detection equipment. PHMSA did not propose a response time requirement for handheld or mobile leak detection equipment in the NPRM, and this final rule does not adopt a response time requirement as part of the performance standard for leak detection equipment. However, PHMSA recognizes that equipment response time can affect the reliability of an operator's leak survey program if their leak survey procedures do not account for the response time of their equipment when defining dwell time requirements for handheld surveys or survey speeds for surveys with mobile equipment. To address this concern, this final rule requires operators to define required dwell times or, for mobile and aerial surveys, the maximum survey speed, in their leak detection procedures in accordance with § 192.763(a)(2)(i). This clarifies the proposed requirement to define allowable environmental and operational parameters for the operator's leak survey equipment and procedures. These considerations are described in greater detail in the discussion of leak survey procedures in section III.E. PHMSA may reconsider standards for response time, particularly for mobile surveys where dwell times are likely shorter, in a future rulemaking.

[297] The time it takes for a gas detector to indicate the actual concentration.

Gas Distribution

Based on the considerations described above, this final rule adopts the GPAC recommendations for the leak detection equipment performance standards as discussed below, except with a revised performance standard based on comments submitted by stakeholders after the GPAC meeting. Notably, it includes separate standards for screening surveys, traditional mobile surveys, and walking surveys with handheld equipment. This final rule includes alternative performance standards for leak detection equipment used in leak surveys of aboveground pipelines and pipelines inside of buildings. For leak surveys of gas distribution lines, an operator must choose to apply one or more of the following performance standards depending on the equipment and survey type:

- For screening surveys using infrared or laser-based leak detection equipment; mobile, aerial, or satellite-based platforms; or using fixed continuous monitoring sensors, the operator's screening survey program must detect leaks with a leakage rate of 0.2 kg/hr or greater with a 90 percent probability of detection.
- For surveys with handheld equipment: Leak survey equipment an operator uses must have a minimum sensitivity of 5 ppm or 5 ppm-m. An operator may also use a soap solution applied directly to the pipeline.
- For surveys with mobile equipment: leak survey equipment an operator uses must have a minimum sensitivity of 5 ppm or 5 ppm-m. The operator must perform the survey within the effective range of detection and maximum survey speed necessary to reliably detect

hazardous leaks as defined in the operators' leak survey procedures (see discussion in section III.E).

Compared to the NPRM, the 5-ppm-within-5-ft performance standard has been simplified to require the use of handheld leak detection equipment with a minimum sensitivity of 5 ppm or 5 ppm-m without the distance requirement. This standard is applicable to walking leak surveys with handheld equipment and certain mobile survey methods. Additionally, this final rule includes an open-path concentration sensitivity standard of 5 ppm-m applicable to handheld open-path gas detectors. The 5 ppm and 5 ppm-m standards are attainable by mainstream, commercially available leak detection devices used throughout the industry, including virtually all FIDs and most laser-based gas detectors.

While not an advanced technology, this final rule also adopts suggestions from the Industry Trades and other operators to permit operators to use a soap solution applied directly to the pipeline facility as an allowable method for performing leak surveys and for pinpointing the location of leaks. In this method, a worker applies a soapy solution or other fluid capable of visually identifying leaks directly to a pipeline facility and then visually inspects the pipeline. Any escaping gas from a leak will cause bubbles or other visual indications of a leak in the solution. These "soap tests" are described as a leak survey method in the GPTC guide and can reliably detect and locate even very small leaks on aboveground pipeline facilities or other facilities that are directly accessible to operator personnel.

For gas distribution pipeline screening surveys using IR or laser-based leak detection equipment; mobile, aerial, or satellite-based platforms; or using fixed continuous monitoring sensors, this final rule adopts a leak-rate detection threshold of 0.2 kg/hr based on comments submitted during the comment period following the March 2024 GPAC meeting, rather than the 0.5 kg/hr criterion recommended by the GPAC. In comments submitted after the GPAC meeting, a joint industry trade group comment observed that the GPAC-recommended detection threshold of 0.5 kg/hr corresponded to a leak rate of approximately 25 SCFH, over double the value that the GPAC recommended for leaks that pose a potential future hazard to people and the environment due to their release rate. Under the GPAC-recommended standard, an operator could theoretically fail to detect leaks with a release rate between 10 and 25 SCFH with a compliant leakage survey program; in other words, leaks that merit repair on an accelerated timeline due to the degree of environmental harm might not be detected at all during an operator's leak survey. The joint industry commenters recommended resolving this issue by revising the performance standard to correspond to the environmentally significant leak criteria of 0.2 kg/hr, corresponding to the 10 SCFH grade 2 criteria, rather than require a traditional leak survey in addition to a screening survey. PHMSA intends to permit mobile screening surveys as a standalone leak survey method and agrees that revising the performance standard for ALDPs accommodates the use of such technologies without imposing unnecessary costs or compromising the public safety and environmental protection objectives of this final rule. This also mirrors the GPAC recommendations for gas transmission lines, where the detection limit for screening surveys on gas transmission lines corresponded to the GPAC-recommended grade 2 release-rate criterion of 10 kg/hr, ensuring that operators are required to reliably detect leaks that pose a potential hazard to the environment.

In written comments on the NPRM, the Joint Environmental comment supported a flow-rate standard of 0.5 kg/hr; however, the commenters provided an analysis using the FEAST model that considered the use of a mobile cavity ringdown spectroscopy with a minimum sensitivity of 0.2 kg/hr at 100 percent probability of detection.[298] In their analysis, one scenario evaluated surveys completed every 3 years with a leak detection sensitivity of 0.2 kg/hr and found a 62 percent emissions reduction compared with status quo survey and repair requirements, with an estimated total emissions from leaks equivalent to 5 tons of carbon dioxide emissions per year.[299] This compared favorably to an alternate scenario that evaluated surveys with an assumed performance of 0.5 kg/hr with the same survey frequency and the NPRM's proposed repair requirements and resulted in just under an emissions equivalent to 8 tons of carbon dioxide per year.[300] On the other hand, the Joint Environmental comment analysis found that detection limits at or above 1 kg/hr struggled to reliably find leaks on gas distribution lines at all and actually resulted in higher total emissions than the status quo even with the revised repair requirements proposed in the NPRM, since relatively large distribution line leaks that would have been identified in traditional walking surveys could be missed by insufficiently sensitive technology.

A comment from multiple gas gathering industry trade associations included a report prepared by Highwood for API that similarly evaluated leak detection technology. While that

[298] Joint Environmental comment. August 17, 2023. at page 52, and attachment A at slide 6. (PHMSA-2021-0039-26522).
[299] Joint Environmental comment. August 17, 2023. Attachment A at slide 21. (PHMSA-2021-0039-26522)
[300] Joint Environmental comment. August 17, 2023.PHMSA-2021-0039-26522 Attachment A at slide 13. (PHMSA-2021-0039-26522)

analysis was focused on gas gathering lines in production basins and did not evaluate a standard below 1 kg/hr, it did evaluate advanced mobile leak detection equipment like the technology described in the Joint Environmental comment. The three examples of equipment the commenter evaluated each achieved performance that would meet the 0.2 kg/hr (10 SCFH) standard at a 100 percent probability of detection,[301] demonstrating the appropriateness and practicability of the revised 0.2 kg/hr standard for this application.

In conclusion, a 0.2 kg/hr performance standard for screening surveys of gas distribution lines results in significant emissions reduction, reliably detects leaks exceeding the GPAC-recommended grade 2 criteria for leaks that pose a potential future hazard to the environment and is consistent with the performance of commercially available advanced technology. As noted in the preamble to the NPRM and public comments, on average, gas distribution systems tend to have large amounts of relatively small leaks compared to gas transmission and gas gathering systems, where a small proportion of "super-emitting" leaks and incidents dominate total fugitive emissions volumes. Consequently, a lower detection limit is necessary to significantly reduce emissions. Additionally, since gas distribution systems are almost always, by function, located in and around populated areas, a lower detection limit will help ensure that operators detect leaks with relatively small surface expressions but with potentially flammable accumulations of gas belowground or inside of buildings before they have the chance to cause a damaging or deadly incident.

[301] Highwood Emissions Management for American Petroleum Institute. "PHMSA Methane Detection Requirements Analysis," page 17. (Aug 16, 2023). (PHMSA-2021-0039-26370).

Gas Transmission and Regulated Gas Gathering Lines

For gas transmission and regulated gas gathering lines, this final rule adopts the GPAC recommendations for the leak detection performance standards as discussed below. This final rule includes alternative standards for the equipment and methods used for leak surveys of aboveground equipment and pipelines inside of buildings, which are discussed separately below. For leak surveys of gas transmission pipelines and regulated gas gathering lines, an operator must choose to apply one or more of the following performance standards depending on the equipment and survey type:

- For screening surveys using IR or laser-based leak detection equipment; mobile, aerial, or satellite-based platforms; or using fixed continuous monitoring sensors, the operator's screening survey program must detect leaks with a leakage rate of 10 kg/hr or greater with a 90 percent probability of detection.
- For surveys with handheld equipment: Leak survey equipment operators use must have a minimum sensitivity of 5 ppm or 5 ppm-m. An operator may also use a soap solution applied directly to the pipeline.
- For surveys with mobile equipment: Leak survey equipment operators use must have a minimum sensitivity of 5 ppm or 5 ppm-m. An operator must perform the survey within the effective range of detection and at the survey speed necessary to reliably detect hazardous leaks as defined in the operator's leak survey procedures (see discussion in section III.E).

While this revision represents a less sensitive performance standard compared with gas distribution lines and is likely less sensitive than the proposed requirements, it still results in substantial reductions in emissions from leaks from gas transmission and regulated gas gathering pipelines. By explicitly accommodating screening surveys with commercially available aerial survey and continuous monitoring technologies, this change ensures that the final rule, pursuant to PHMSA's statutory obligations in 49 U.S.C. 60102, has safety and environmental benefits that justify its costs. While it is possible to perform leak surveys of gas transmission and regulated gas gathering lines using equipment that satisfies the performance standard adopted for gas distribution lines, such standards would preclude the use of more cost-effective survey methods and fail to provide significant additional environmental benefits. As described below, in the final RIA, and in public comments, leaks on gas transmission and regulated gas gathering lines are larger on average than leaks form gas distribution lines and emissions from leaks are more highly concentrated among a small number of relatively large leaks. A highly restrictive technology standard is therefore not necessary in order to achieve significant reductions in emissions from such facilities, but would increase costs to perform leakage surveys (by requiring more expensive equipment or less cost-effective survey methods) and repairs (since more leaks are discovered and subject to repair requirements). Particularly for gas transmission lines, an overly sensitive technology requirement risks failing to meet PHMSA's statutory obligation to ensure that standards have benefits that justify their costs under 49 U.S. 60102. Adopting recommended standards found by the GPAC to be reasonable, practicable, cost-effective, and practicable and certain recommendations from public comments provides numerous additional benefits, which are described in greater detail in the following paragraphs.

This final rule improves compatibility between PHMSA's regulations and the EPA's emissions monitoring requirements applicable to portions of gas transmission pipeline facilities, particularly for aboveground facilities. As noted in the discussion of the flow-rate-based alternative above, the ALDP performance standard established in this final rule is compatible with the EPA alternative test method[302] for emissions monitoring for all but one of the survey frequencies allowed under that program in Table 1 to 40 CFR subpart OOOOb; any alternative test method approved by the EPA with a minimum sensitivity of 10 kg/hr or less satisfies the ALDP performance standard for screening surveys established through this final rule in 49 CFR part 192 and minimum survey frequency requirements in § 192.706. If an operator is using an alternative test method for EPA emissions monitoring of aboveground equipment with monthly monitoring surveys with a sensitivity of 15 kg/hr or less and annual OGI, the monitoring surveys would not meet the 10 kg/hr standard adopted in 49 CFR 192.763(b)(1)(i). However, an operator could still meet the requirements of 49 CFR 192.706 and 192.763 with the annual OGI survey if they perform additional leakage surveys during the calendar year to meet the frequency of surveys required at 49 CFR 192.706(b)(1)(i). Alternatively, an operator could request an alternative performance standard under 49 CFR 192.763(d). As described in greater detail in the

[302] 40 CFR 60.5398b and table 1 to subpart OOOOb permit periodic screening surveys with a flow-rate based detection limit as an alternative to monitoring in accordance with EPA Method 21 or with OGI at prescribed intervals as specified in 40 CFR 60.5397b. 40 CFR 60.5398c includes equivalent model rules that could be used in State and Tribal plans.

discussion of equipment sensitivity requirements for leak surveys of aboveground and indoor facilities below, PHMSA has revised the standards for leak surveys of exposed piping in this final rule for greater harmonization with EPA requirements, including allowing the use of OGI.

PHMSA expects the changes to the performance standard will reduce the need for operators to request an alternative performance standard in accordance with § 192.763(d), particularly for aerial leak surveys that should be able to achieve a 10 kg/hr leakage survey sensitivity. However, recognizing the potential for emerging technologies or practices, this final rule adopts the GPAC recommendation to allow an operator to request an alternative performance standard for leak detection equipment and methodology for gas transmission and regulated gas gathering pipelines regardless of class location. The NPRM restricted this allowance to pipelines in Class 1 and Class 2 locations due to their lower risk to the public. PHMSA recognizes the potential operational difficulty of applying a different performance standard on a class location basis. If an operator requests an alternative performance standard equipment and methods used to perform leak surveys of higher-risk Class 3 and Class 4 locations, the final rule requires the operator to include in their notification and request for approval a description of the measures the operator would take to address the higher potential consequences of a leak in those areas. While some environmental groups and technology providers suggested a higher sensitivity rate of 4 kg/hr for gas transmission lines, a 10 kg/hr rate permits operators to use a larger number of aerial survey technology providers when performing leak surveys. Additionally, the higher threshold is also more likely to be able to accommodate technologies that are still in development, such as alternative continuous monitoring methods or satellite monitoring while remaining sufficiently stringent to result in significant reductions in gas emissions. Compared with gas distribution lines, a lower sensitivity is justified by the fact that the average release volume from a leak on a transmission line is higher on average compared with gas distribution lines that operate at much lower pressure. Additionally, the total emissions from gas transmission pipeline leaks are relatively low, reducing the need for highly sensitive detection. On the other hand, emissions volumes from gas gathering lines have been observed to be relatively high; however, emissions studies described in section II.B.3 and in public comments on this rulemaking show that the majority of emissions from such facilities are caused by a small number of large releases. Therefore, a high sensitivity standard is not necessary in order to achieve significant reductions in total emissions from leaks on gas gathering pipelines. The 10 kg/hr criterion for leak surveys was supported by the unanimous recommendation of the GPAC and was supported in public comments for gas transmission and gas gathering systems in comments from industry trade associations and for gas gathering lines specifically in comments from environmental groups. As described in the summary of comments, public comments from the Joint Environmental comment and supporting material provided by API and Highwood on behalf of the Industry Trades included modeling demonstrating that a 10 kg/hr performance standard for annual screening surveys resulted in slightly less emissions reductions compared with a 3 kg/hr or 4 kg/hr standard, but it expands the scope of allowable technology providers and reduces costs and environmental impacts associated with performing repairs or replacements for smaller-volume leaks.

Finally, this final rule addresses consistencies between PHMSA's and the EPA's performance standards for ALDPs of aboveground gas transmission pipeline facilities consistent with the GPAC recommendations and public comments. Considering the similarity between emissions sources covered by the EPA methane emissions monitoring standard and emissions sources from aboveground gas transmission and regulated gas gathering pipeline facilities (e.g., compressor stations, metering and regulating stations, and other similar facilities), this final rule specifies that survey methods permitted under the EPA's regulations at 40 CFR 60 subparts OOOOa through OOOOc satisfy the leak survey performance standards finalized at 49 CFR 192.763. Most notably, this permits operators to perform OGI surveys on aboveground equipment on gas transmission and regulated gas gathering pipelines. This allowance also includes EPA Method 21 emissions monitoring and the alternative test methods included in the 2024 EPA final rule at 40 CFR 60.5398b and 40 CFR 60.5398c. An operator using EPA Method 21 and most alternative test method-approved methods would meet the requirements of this final rule under the 5 ppm and 5 ppm-m concentration sensitivity standard for handheld leak detection equipment and the 10 kg/hr leak rate standard. However, revising this final rule with a direct reference to aboveground facilities clarifies that operators who are able to document compliance with the performance standards for the EPA emissions monitoring requirements for aboveground facilities would be able to document compliance with PHMSA leak survey standards for aboveground facilities, which simplifies compliance for operators that use EPA-approved technologies and procedures for leak surveys for aboveground facilities. This change allows operators to use effective survey methods where they are appropriate and is expected to reduce compliance costs by allowing the use of equipment, personnel, and procedures that exist for emissions monitoring of EPA-jurisdictional facilities.

Standards for leakage surveys inside of buildings.

To address the GPAC recommendation to consider alternative performance standards for leak detection equipment inside of buildings, this final rule establishes alternative standards for leak surveys of aboveground equipment and pipelines inside of buildings that an operator may follow in lieu of the generally applicable leak survey requirements for gas transmission, regulated gas gathering, and gas distribution lines. Similar to those requirements, an operator must select one of the listed standards but is otherwise free to select one or more methods for performing leak surveys. An operator using the alternative standards for surveys of pipelines aboveground or inside of buildings must use equipment meeting one or more of the following standards:

- Handheld equipment must have a minimum sensitivity of 1 percent LEL (500 ppm for methane gas).
- An operator may perform a leak survey by applying a soap solution directly to the pipeline and visually inspecting the pipeline for indications of leas (i.e., soap bubbles).
- An operator may use fixed continuous monitoring equipment of 500 ppm or 500 ppm-m to perform leak surveys of facilities within the effective range of the device as defined in the operator's procedures.

- For gas transmission and regulated gas gathering lines, an operator may use non-optical continuous monitoring systems, subject to the leak-rate performance standard at § 192.763(b)(1)(i) or the alternative performance standard at § 192.763(d).
- Except for gas distribution service lines, an operator may perform leak surveys with OGI equipment and procedures meeting the requirements of appendix K of 40 CFR part 60.

As noted earlier, the alternative minimum equipment sensitivity standard of 500 ppm, equivalent to 1 percent LEL of methane gas, for leak surveys or continuous monitoring sensors inside of buildings addresses the GPAC recommendation to consider standards for inside piping. Based on the current state of leak detection technologies, a lower sensitivity requirement inside of buildings expands the allowable technology options to include most CGIs, a greater number of semiconductor gas detectors, and a greater number of continuous gas detectors or residential gas detectors as described in public comments and consistent with PHMSA's review of current leak detection technology. PHMSA agreed with comments contending that those devices are fit for purpose for leak surveys inside of buildings and notes that these devices are intrinsically safe and therefore have a minimal risk of creating an ignition source. This is an especially important consideration for leak surveys and investigations inside of buildings where both the likelihood and consequences of a flammable, hazardous atmosphere are greater compared with leak surveys performed elsewhere. Additionally, PHMSA was persuaded by arguments raised in the comments it received that environmental conditions for leak surveys of exposed pipelines inside of buildings present fewer obstacles to identifying leaks, which would justify a lower performance standard. Specifically, pipelines inside of buildings are generally directly accessible by operator personnel and not subject to soil conditions, high winds, and other environmental conditions that could interfere with successfully identifying leaks.

As mentioned in the previous paragraph, several commenters recommended alternative standards for fixed continuous monitoring equipment from between 40 ppm to 500 ppm or more. In comments submitted during the comment period for the GPAC meeting, industry trade groups suggested a threshold of 500 ppm or 500 ppm-m for fixed continuous monitoring equipment. This proposed standard is likely intended to correspond to the capability of residential methane detectors, such as the remote "Natural Gas Detector" program described in comments from Con Edison, a gas distribution operator. In Con Edison's comments, they described a pilot program where they installed natural gas detectors on customer meter assemblies or the point where gas service lines enter the structure. According to Con Edison, the devices have a minimum sensitivity of 1 percent LEL (500 ppm) and are configured to alarm when gas concentration reaches 10 percent LEL. Additionally, the devices can communicate with the operator's emergency response center and provide real time indications of leaks. As noted in the preamble to the NPRM, PHMSA is supportive of the deployment of residential methane monitoring and alarm systems and recognizes the safety benefit of accommodating technology that can provide real-time notification of hazardous conditions to customers and operators. Therefore, this final rule adopts the 500 ppm or 500 ppm-m standard to accommodate such systems, consistent with the performance of commercially available residential methane detectors deployed by operators as described in public comments; however, the equipment must be located within the effective range of the device defined in the operator's ALDP procedures (see the discussion in III.E), and the operator is required to perform a follow-up-investigation to pinpoint the source if any indications of leaks are discovered. As mentioned in the discussion of the "500 ppm" fugitive emission definition used in EPA methane monitoring requirements and in public comments from CSU/SMU, the probability of detection with a point sensor decreases rapidly with distance from the facility. Despite the advantages of continuous monitoring with respect to timely detection of emissions and hazardous conditions, operators must carefully consider the effective range and position of these devices when choosing the continuous monitoring standard at the minimum detection limit of 500 ppm to help ensure that leaks from the facility are reliably detected. Generally, this would require the sensor to be located as near as practicable to probable leak locations on the pipeline facility, such as the example from public comments where gas detectors were directly connected to customer meter assemblies. If detection from greater distances is necessary, an operator should consider more sensitive equipment, open-path detectors, supplemental surveys of facilities outside of the effective range of the sensor, or other methods using the leak rate performance standard.

In a comment submitted after the March 2024 GPAC meeting, AGA et al. included in their recommended regulatory text an allowance for the use of a "non-optical continuous monitoring system (e.g., acoustical or pressure monitoring systems)" for non-buried gas transmission lines but did not describe performance standards for such systems. PHMSA reiterates that this final rule is intended to establish technology-neutral standards for effective leak detection systems. Therefore, this final rule includes reference to such continuous monitoring systems to clarify that they are not explicitly prohibited. However, this final rule requires that non-optical continuous monitoring systems meet either the 10 kg/hr leak rate performance standard at paragraph (b)(1)(i) applicable to screening surveys or the alternative performance standard notification process at paragraph (d). This change clarifies that operators may use these alternative methods for continuous monitoring for leaks, provided the methods meet a minimum standard of performance.

The final option allows operators to use OGI cameras to perform leak surveys of certain aboveground equipment and pipelines located inside of buildings, provided the survey meets the EPA's requirements for methane gas emissions monitoring in appendix K to 40 CFR part 60. Appendix K to 40 CFR part 60 is an established standard for the use of OGI in the EPA's fugitive emissions monitoring and repair requirements for gas processing plants subject to emissions monitoring with OGI under the EPA regulations and includes enhanced requirements compared with the more general standards previously adopted for compressors and wells. Consistent with Appendix K to 40 CFR part 60 and the emissions monitoring requirements in 40 CFR 60.5397a, 60.5397b, an operator must investigate, grade, and repair any emissions visible via OGI in accordance with 49 CFR part 192. This change permits an operator to use OGI technology as a leak survey method for aboveground facilities, other than distribution service lines, provided the equipment and survey procedures meet the EPA requirements in Appendix K of 40 CFR part 60. The GPAC recommendation addressed OGI for gas transmission lines; however, follow-up comments submitted after the GPAC meeting requested that PHMSA consider the use of OGI for gas distribution facilities as well. Unlike gas transmission lines, gas distribution lines are not subject to EPA emissions monitoring requirements in 40 CFR part 60 subpart OOOOa through OOOOc and operate at lower pressure. PHMSA has concerns about the reliability of detecting leaks from customer meter assemblies or risers, which are typically located adjacent to occupied structures, due to the relatively low pressure and flow rate within such lines. Therefore, this restriction should not affect the practicability of operators performing leak surveys of distribution service lines. Allowing operators to use OGI for aboveground service lines would not improve the practicability of such surveys. An operator would still be obligated to survey the buried portion of the service line via other means, since OGI surveys are not effective for, and therefore not permitted for, buried pipelines. Additionally, alternative means of detecting leaks on gas distribution lines at a distance, such as open-path infrared and laser-based detectors, are in widespread use among distribution operators. On the other hand, other types of facilities, such as city gate stations and regulator stations, may have characteristics more similar to aboveground facilities, such as wells and compressor stations, that are routinely surveyed using OGI.

Allowing OGI, in combination with the alternative equipment standard of 500 ppm for handheld equipment, aligns the performance standards for equipment used for leak surveys of aboveground and indoor facilities with equivalent requirements for fugitive emissions monitoring surveys in the EPA's 40 CFR part 60, subparts OOOOa and OOOOb requirements, when performing such surveys using EPA Method 21 or OGI. While, as described earlier, an equipment performance standard based on the EPA definition of a fugitive emissions when using EPA Method 21 (an instrument reading of 500 ppmv or more) in 40 CFR 60.5397a and 60.5397b is not equivalent to a 500 ppm equipment standard for surveys of buried pipeline facilities, pipeline facilities that are located aboveground or inside of buildings are directly accessible to operator personnel and equipment and therefore more comparable to wells and compressors subject to EPA emissions monitoring standards. This harmonization simplifies the compliance burden for operators of regulated gas gathering lines and gas transmission pipelines with facilities jurisdictional to both PHMSA and the EPA or to a Federal, State, or Tribal plan, as the case may be. While this final rule exempts facilities covered by EPA methane emissions monitoring regulations, including existing sources regulated under a federal plan or an EPA-approved State or Tribal plan, allowing operators to use similar methods for performing leak surveys for other types of aboveground facilities allows operators to use equipment, procedures, and personnel for leak surveys required by 49 CFR part 192 that they may already use to comply with similar EPA, State, or Tribal requirements.

Equipment standards for pinpointing leaks

In addition to the general standards for performing leak surveys of gas distribution, gas transmission, and regulated gas gathering lines, this final rule adopts general performance standards for leak detection equipment used whenever a follow-up investigation to pinpoint the source of a leak indication is required. These requirements mirror the standards for handheld equipment described above and are as follows:

- Handheld equipment must have a minimum sensitivity of 5 ppm or 5 ppm-m, except that operators may use handheld equipment with a minimum sensitivity of 1 percent

LEL (500 ppm for methane) for locating leak indications of leaks on non-buried pipelines and pipelines inside of buildings.

- An operator may use a soap solution or an equivalent solution applied directly to the pipeline to locate the source of a leak.
- An operator may visually locate the source of leak indications on pipelines submerged in water (e.g., bubbles).

This final rule does not adopt suggestions from comments to remove the requirement for operators to pinpoint the location of leaks with handheld equipment. The handheld equipment standard is a simple and enforceable means to help ensure that operator personnel can directly locate the source of the leak on the pipeline for eventual repair or monitoring. An operator may still use unmanned aerial systems, stationary sensors, and other methods to perform initial screening surveys or to supplement handheld equipment, but operators must identify the ultimate location of the source of the leak with handheld equipment. The adoption of a 5 ppm-m standard allows operators to use handheld open-path devices that can assist in locating the source of leaks at a distance but within line-of-sight of the device operator, similar to the capability of UAS-mounted leak detection equipment, which must also be used within line-of-sight in accordance with 14 CFR 107.31.

Similar to the alternative equipment sensitivity standard for leak surveys inside of buildings, an operator may also use equipment with a minimum sensitivity of 1 percent LEL (500 ppm for methane). As noted above, an operator may supplement equipment that meets this standard with other, potentially less-sensitive equipment. This addresses comments PHMSA received concerned that the proposed sensitivity requirements for handheld equipment would require operator leak responders to replace all their equipment used for the initial assessment of potentially hazardous atmospheres. Inside of buildings, CGIs and other equipment sensitive to 1 percent LEL are explicitly permitted in this final rule, and operator leak responders can make an initial grade determination with less-sensitive equipment as long as the leak is ultimately pinpointed with another approved method.

Alternative Performance Standards and Other Comments

This final rule adopts the GPAC recommendation and revises the scope of the proposed alternative performance standard request process to cover all pipelines under part 192. The NPRM limited the scope of this alternative performance standard to gas transmission lines in Class 1 and Class 2 locations due to the lower public safety risk in those locations and anticipated operators would use the process to approve aerial surveys and other alternative technologies. However, the proposed requirements of the alternative performance standard included descriptions of higher-risk areas on the pipeline and measures the operator must take to address those public safety risks. Since PHMSA would object to any request that failed to adequately address public safety risk, it is not necessary to exclude gas distribution pipelines or pipelines in Class 3 and Class 4 locations. Expanding the scope of the alternative performance standard process may increase the number of notifications to PHMSA. However, adopting the performance standards for leak detection equipment described earlier in this section, which establishes standards compatible with a broader set of technologies and theoretically reduces the need for an alternative standard, should address concerns that PHMSA would not review all notifications within the 90-day review window. Finally, as noted in section III.B, this final rule removes the proposed exception from operators using leak detection equipment for leak surveys of onshore transmission and gathering lines in Class 1 and Class 2 locations with a notification and approval under § 192.18; this change helps ensure that all onshore gas pipelines are surveyed using appropriate leak detection technology, potentially addressing concerns with the alternative performance standard.

E. Advanced Leak Detection Program- Program Elements—§ 192.763

1. Summary of PHMSA's Proposal

General

PHMSA proposed that each operator's written ALDP would contain the following elements: (1) a list of leak detection equipment used by the operator for performing leak surveys, pinpointing leak locations, and investigating leaks; (2) leak detection practices and procedures; (3) defined leak survey frequencies; and (4) procedures for periodic evaluation and improvement. These proposals complement the performance standards discussed in section III.D.

List of Leak Detection Equipment

The first proposed element in an ALDP is the list of leak detection technologies that the operator would use to perform leak surveys, investigate leaks, and pinpoint leak locations. These technology requirements were proposed at § 192.763(a)(1) of the NPRM. PHMSA proposed to require that all operators use leak detection equipment when performing leak surveys of all regulated gas gathering, gas distribution, and gas transmission lines, with two limited exceptions. First, for leak surveys of submerged offshore pipelines, which could be performed using human senses due to visible indications of a leak on submerged lines.[303] And second, for leak surveys of certain gas transmission and gathering lines in Class 1 and Class 2 locations, which could be performed without leak detection equipment (i.e., relying solely on human or animal senses) after providing notice to PHMSA that would include tests or analyses demonstrating that the survey method would either meet the program-wide performance standard under § 192.763(b) or the alternative performance standard under § 192.763(c).

As discussed in section III.D, the NPRM proposed to require that each item of leak detection equipment would meet the proposed equipment sensitivity performance standard at § 192.763(a)(1)(ii) and all the leak detection technologies used in an operator's ALDP would together meet the proposed program-wide performance standard described at § 192.763(b).

PHMSA proposed at § 192.763(a)(1)(iii) to require operators to select their leak detection equipment based on a documented analysis that considers, at a minimum, the gas being transported and the size, configuration, operating parameters, and operating environment of the operator's system. In keeping with the section 113 mandate of the PIPES Act of 2020, the NPRM would require operators to consider using the following advanced leak detection technologies and methods: continuous monitoring via stationary gas sensors, pressure monitoring, or other means; handheld leak detection equipment; periodic surveys using equipment mounted on ground vehicle, satellite, or aerial platforms; periodic surveys with optical, infrared, or laser-based handheld devices; and systemic use of other technologies capable

[303] See the discussion in section III.B.1 for more details on transmission and gathering pipeline leak detection survey requirements and this proposed exception.

of detecting and locating leaks consistent with the proposed ALDP performance standard at § 192.763(b). While PHMSA regulations require the use of stationary gas detection systems on compressor stations under part 192 and the monitoring of enclosed buildings and other areas that can have the presence of LNG or other hazardous fluid under part 193, PHMSA solicited public comment on whether continuous monitoring systems should be required for other types of pipeline facilities, including whether continuous monitoring would be most appropriate at any particular facilities or locations, or in other particular conditions.

Leak Detection Procedures

The second program element proposed at § 192.763(a)(2) consisted of the operator's written leak detection procedures. An operator's ALDP, as proposed, would be required to include procedures for performing leak surveys, investigating and pinpointing leaks, validating equipment performance under the proposed minimum sensitivity performance standard (§ 192.763(a)(1)(ii), discussed in further detail in section III.D), and maintaining and calibrating leak detection equipment.

For leak surveys and for investigating and pinpointing leaks, PHMSA proposed to require that operator procedures would provide instruction on whether and how each type of leak detection equipment included in the ALDP would be used in performing those tasks. This proposal would have further required an operator to define under which conditions leak survey procedures may and may not be used, including factors such as temperature, wind, time of day, precipitation, and humidity. Additionally, PHMSA proposed to require that an operator's procedures be consistent with any instructions and allowable operating and environmental parameters issued by the leak detection equipment manufacturer(s) to help ensure equipment effectiveness.

PHMSA proposed at § 192.763(a)(2)(ii) to require that, once an operator detects an indication of a leak (through leak surveys, patrols, or otherwise), the operator's ALDP must also include procedures for investigating and pinpointing leak locations to help ensure that operators properly locate the source of a leak so that the operator can appropriately grade and remediate the leak. For onshore pipelines and offshore pipeline facilities above the waterline, PHMSA proposed at § 192.763(a)(2)(ii) to generally require that operators pinpoint leak locations using handheld leak detection equipment meeting a minimum sensitivity performance standard. However, PHMSA proposed to allow operators of submerged offshore pipelines, including riser piping up to the waterline, to pinpoint leak locations without the use of leak detection equipment because bubbles from leaks on submerged pipeline leaks are visibly conspicuous to the human eye. If an operator pinpointed a leak's location with handheld leak detection equipment during an initial leak survey, that initial survey could satisfy the proposed pinpointing requirement.

Proposed § 192.763(a)(2)(iii) further required that an operator's ALDP would include procedures for validating that all leak detection equipment used in the ALDP meets the 5-ppm minimum sensitivity performance standard at § 192.763(a)(1)(ii) and the 5-ppm-within-5-feet programmatic performance standard at § 192.763(b) prior to initial use. PHMSA specifically proposed that operators would take measurements against a known concentration of gas and maintain these validation records for 5 years after the date each device ceased to be used in the operator's ALDP.

Finally, the NPRM proposed at § 192.763(a)(2)(iv) that an operator's ALDP would include procedures for (1) the maintenance and calibration of leak detection equipment, including, at a minimum, any such procedures recommended by the equipment manufacturer, (2) the recalibration or replacement of leak detection equipment following an indication of malfunction, and (3) record maintenance validating equipment calibration and failures for 5 years after the date that an individual device is retired by the operator.

Leakage Survey Frequency

The third element of an ALDP, as proposed in the NPRM, was the frequency of leak surveys. Minimum leak survey frequencies were defined at § 192.723 for gas distribution pipelines and at § 192.706 for gas transmission, offshore gathering, and Types A, B, and C onshore gathering pipelines. However, under proposed § 192.763(a)(3), an operator's ALDP would consider whether more frequent leak surveys were necessary to meet the proposed ALDP program-wide performance standard at proposed § 192.763(b). For example, an ALDP might require more frequent leak surveys to meet the program-wide performance standard when using less-sensitive equipment, surveying under challenging conditions, or surveying facilities known to leak based on their material, design, or past operating and maintenance history. PHMSA observed in the NPRM that operator adoption of continuous monitoring systems would be one way in which an ALDP could require more frequent surveying of leaks.

Program Evaluation and Improvement

PHMSA further proposed in the NPRM at § 192.763(a)(4) that an operator's ALDP would also include procedures for program evaluation and improvement. PHMSA proposed that operators would reevaluate their ALDPs at least annually, considering, at a minimum, the performance of the leak detection equipment used, the adequacy of their leak survey procedures, advances in leak detection technologies and practices, the number of leaks initially detected by the public, the number of leaks and incidents on the operator's system, and estimated emissions from leaks detected pursuant to the operator's ALDP. Based on this evaluation, an operator would be required to make any changes to their ALDP necessary to locate and eliminate leaks and minimize releases of gas and would document any ALDP improvements.

Recordkeeping

Finally, PHMSA proposed at § 192.763(b)(2) that an operator would maintain records validating that their ALDP meets the program-wide performance standard while the ALDP is in use and for at least 5 years after the date the ALDP is no longer in use by the operator.

2. Summary of Public Comments

General

PHMSA received a wide range of suggestions from commenters regarding ALDP program elements. For example, individuals participating in letter-writing campaigns, other individual commenters, and multiple public and environmental advocacy groups opposed the flexible nature of PHMSA's proposed ALDP elements, suggesting instead that PHMSA should establish prescriptive standards for detecting leaks. On the other hand, operators argued that leak detection requirements beyond those set forth in the GPTC guide were unnecessary and opposed being required to prepare a written ALDP. The GPTC requested clarification that the proposed

§ 192.763 ALDP would satisfy the requirement to have an effective leak management program under DIMP in subpart P of part 192.

List of Leak Detection Equipment

The NTSB recommended that "PHMSA require all operators of natural gas transmission and distribution pipelines equip their supervisory control and data acquisition (SCADA) systems with tools to assist in recognizing and pinpointing the location of leaks, including line breaks."

Fiber Optic Sensing Association recommended performance-based comparisons of technologies rather than a comparison based on the similarities of the different approaches. Picarro, Inc. recommended that PHMSA adopt a definition of "Advanced Leak Detection" that reflects currently available technology. Multiple leak detection providers and industry representatives discussed leak detection equipment, including odorants, a remote sensing aerial survey system, aerial LIDAR technology, Gas Mapping LIDAR, Distributed Fiber Optic Sensing, satellites, quantitative OGI, and continuous monitoring technologies. An operator commented that PHMSA should allow soap tests in addition to handheld detection devices for pinpointing leaks.

Multiple industry representatives and an individual commenter opposed requiring operators to analyze the effectiveness of each of the example technologies at § 192.763(a)(1)(iii). The individual commenter recommended that PHMSA state what technology they accept or reword the regulation to state "consider the use of the technologies and analyze what is chosen." Oleksa and Associates, Inc. and multiple pipeline operators commented that PHMSA should accept manufacturer validation of the performance of leak detection equipment and that requiring the operator to perform this validation would be a burden for smaller operators. Bridger Photonics, Inc proposed that gas sensing technologies be qualified based on third-party testing according to standardized testing protocols to increase transparency and uphold high scientific standards. Atmos Energy Corporation suggested that PHMSA should review available technologies in partnership with industry. Another operator commented that while their existing procedures incorporate many elements proposed for PHMSA's ALDP requirements, validating and documenting performance implies a need to duplicate leak surveys with a follow-up evaluation to prove that the leak survey was effective, and this would be burdensome and unnecessary.

The Pipeline Safety Trust, Joint Environmental commenters, Physicians for Social Responsibility, the Clean Air Council, Dakota Resources Council opposed permitting leak surveys relying solely on human senses in non-HCA class 1 and class 2 locations, even with PHMSA approval. These commenters argued that sole use of human senses was inaccurate, and that aerial survey studies show that pipelines in rural areas are subject to significant leaks. These organizations commented that Thermo Fischer Scientific likewise opposed allowances for the use of human senses, commenting that such methods are subjective, inaccurate, and imprecise compared with gas analyzers and other instruments. Multiple operators similarly commented about the inefficacy of human senses in comments disputing the benefits of right of way patrols. On the other hand, the Marcellus Shale Coalition commented that PHMSA should permit AVO surveys (leakage surveys with human senses, see II.E) for regulated gas gathering lines in Class 1 locations.

An individual commenter, Physicians for social Responsibility Pennsylvania, Thermo Fisher Scientific, Waterspirit, and Project Canary, PBC, supported additional continuous monitoring requirements to facilitate increased LDAR, decrease costs, and decrease labor. However, Thermo Fisher Scientific noted that there could be challenges with using continuous monitoring in areas that are too condensed.

While PHMSA did not propose to require continuous monitoring, in a response to a request for comment on the potential for requirements to install continuous monitoring on new or existing pipelines, Kinder Morgan, Inc. commented that PHMSA did not provide enough detail, or a satisfactory risk assessment related to potential continuous monitoring requirements to justify adopting such standards on existing pipelines in a final rule. The Industry Trades similarly commented that PHMSA made no justification for applying such requirements to other pipelines. Boston University School of Public Health and Physicians, Scientists, and Engineers for Healthy Energy listed continuous monitoring, along with detailed data collection across all pipes and facilities and more granular leak data reporting requirements, as necessary to improve emissions reductions efforts.

PPL Corporation commented that implying that leak surveys with handheld equipment require the use of locating equipment to verify that the leak detection equipment is sampling the correct area is impractical and redundant, arguing that this requirement would require more time, personnel, and equipment—all of which would increase operating costs and make handheld surveys less desirable. Furthermore, they argued that operators would still need to perform handheld surveys if companies transitioned to mobile leak surveys, which would render mobile leak surveys impractical and duplicative.

Leak Detection Procedures

The GPTC commented that, in order to address the need to promptly identify leaks that are potentially hazardous to public safety, PHMSA should clarify the language at proposed § 192.763(a)(2) to emphasize that classifying leaks, particularly determining the extent of gas migration, has priority over pinpointing the precise origin of a leak for eventual repair. Similarly, the GPTC noted that the NPRM did not provide a timeframe for pinpointing leaks after the initial indication following a screening survey or other leak survey, which they noted has led to uncertainty in the requirements for performing mobile leak surveys under existing code requirements. They suggested that PHMSA require operators to define such a timeframe within their procedures rather than have PHMSA specify a timeframe in the final rule. Finally, the GPTC recommended that PHMSA consider the different types of leak detection equipment and the specific environments for which they are used and adjust the proposed language to allow operators to utilize effective equipment.

A comment from CSU/SMU cited a 2022 study supporting PHMSA's claims in the NPRM's preamble that the effectiveness of leak detection equipment and procedures can be affected by operational parameters of the procedures themselves and environmental factors, such as weather and soil conditions. That study[304] "demonstrated significant variability in detection

[304] Tian, S., S.N. Riddick, Y. Cho, C.S. Bell, D.J. Zimmerle, K.M Smits. 2022b. Investigating detection probability of mobile survey solutions for natural gas pipeline leaks under different atmospheric conditions. Environmental Pollution.

performance based on survey distance and speed, leak rate, atmospheric stability, and wind speed." The commenter noted their testing indicated that the probability of detection during a mobile survey decreases dramatically with an increase in speed and distance from the leak location and concluded that, by using measurement data on simulated surveys with different environmental and operational parameters, "an operator can select suitable survey speeds, heights, and distances under different weather conditions" to achieve a particular probability of detection.

Oleksa and Associates commented that requirement to maintain and calibrate equipment is a good practice but that a regulation for it is not necessary because operators already do so as a best practice.

Air Liquide Large Industries U.S. L.P. commented that the requirement for operators to pinpoint leaks with handheld leak detection equipment was overly prescriptive and could prevent the adoption of alternative technologies or methods for locating pipeline leaks requiring repair. As an example, they commented that they have been testing drone-based hydrogen leak detection that has been more effective than any handheld device available for hydrogen gas detection.

Leakage Survey Frequency

An operator commented that, given the minimum leak survey frequencies prescribed at §§ 192.706 and 192.723, imposing additional mandates related to survey frequency within the ALDP requirements is "redundant and inappropriate."

A leak detection equipment provider provided information supporting the importance of survey frequencies on the effectiveness of gas distribution leak surveys but suggested that prescriptive survey intervals in part 192 would increase survey costs. The commenter instead suggested PHMSA allow operators using advanced mobile leak detection systems to establish their own leak investigation frequencies, potentially combined with a prioritization scheme based on the estimated release rate. They commented that a performance-based approach could achieve safety and emissions goals with lower costs from performing surveys.

An aerial survey technology provider commented that PHMSA should harmonize leak survey frequency requirements with the matrix-based approach proposed by the EPA in the methane emissions monitoring requirements in the then-proposed 40 CFR part 60, subpart OOOOb and OOOOc, as an alternative to quarterly OGI surveys.[305] This matrix-based approach defines the required frequency of emissions monitoring surveys (i.e., leak surveys) as a function of the detection limit of the emissions monitoring method. They commented that the EPA's proposed matrix approach was supported by peer-reviewed modeling tools, including LDAR-Sim and the FEAST model, and demonstrates the tradeoff between detection limits and survey frequency.

Periodic Evaluation and Improvement

An operator commented that "a periodic test and analysis is a good thing, but it should not be necessary to have an engineering test and analysis for this purpose." KOGA commented that an annual reevaluation of the leak detection program is a heavy burden, noting that other

[305] This approach was summarized in Table 20 in the preamble to the New Source Performance Standard SNPRM at 87 FR 74742 and has since been adopted into 40 CFR 60.5433b5433 at Table 1 to Subpart OOOOb of Part 60 and Table 2 to Subpart OOOOc of Part 60.

programs in part 192, such as IM, provide a 3- to 5-year reevaluation interval and recommended the same for the proposed ALDP reevaluation requirements.

A distribution operator commented that the type of analysis proposed for the periodic evaluation of an ALDP would fit more appropriately within the DIMP regulations at § 192.1007(e), which includes data analysis and effectiveness evaluations. Another operator of primarily gas distribution lines commented that, while the rule should incorporate a defined review cycle, the proposed requirements for engineering tests and analyses were ambiguous and vague.

Recordkeeping

The Industry Trades commented that the requirement to maintain program performance records for 5 years after the date the program is no longer in use by the operator is effectively a permanent recordkeeping requirement since an operator is required to continuously maintain an ALDP. Furthermore, they commented that this recordkeeping requirement was adequately addressed elsewhere via the documented program evaluation requirements and equipment performance and calibration recordkeeping requirements elsewhere in the section.

3. GPAC Deliberation Summary

The GPAC discussed ALDP program elements concurrently with the ALDP performance standard described in section III.D. PHMSA provided a briefing on this topic, the GPAC provided an opportunity for public comment on November 28, 2023, and then the GPAC deliberated on November 29, 2023. PHMSA's briefing included a presentation of the proposed regulatory language, including a discussion of its costs and benefits, and an overview of material comments from stakeholders on the proposal. Following the briefing by PHMSA staff, the GPAC provided an opportunity for statements from members of the audience. With respect to program elements in particular, several industry representatives commented that the ALDP standard would require more than 6 months to implement the changes to leak detection equipment, procedures, and training, and recommended a compliance deadline after the deadline for the EPA's proposed 40 CFR part 60, subpart OOOOa through OOOOc standards (see section III.U for greater discussion of compliance timelines). In addition to the concerns described above, commenters representing municipal gas systems stated that the requirement for operators to evaluate a list of example leak detection methods was unnecessary if PHMSA prescribes allowable standards, and this would be particularly burdensome for smaller operators. An operator similarly commented that the proposed annual frequency for program evaluation was overly burdensome and would provide little benefit since evaluating, changing, and training personnel on new programs and procedures is a multi-year, expensive process.

The GPAC discussion focused on the proposed requirement for operators to evaluate the Performance of their ALDP annually. Members broadly agreed on the value of periodic program reviews, but members representing operators and State regulators reiterated concerns raised by public commenters during the proceedings regarding the proposed annual frequency for such reviews. Members agreed in principle that operators should strive for continuous improvement, including making annual incremental changes to plans and procedures, however Committee members representing operators and States cautioned that a comprehensive program evaluation mandated by regulation and subject to audit is necessarily a more rigorous process that can take between 3 to 5 years to prepare, document, and implement. By way of example, PHMSA staff and members representing operators and States described the level of effort expected for similar reviews required for IM programs in subparts O and P of part 192. Members also suggested that incorporating more than 1 year of leak information into program reviews may lead to better evaluation of program performance. Committee members briefly considered a bifurcated approach of annual incremental improvements in addition to less frequent, comprehensive program evaluations, but a member representing an operator noted that annual updates to procedures is addressed in existing § 192.605. Members debated the need for prescribed periodicities for program evaluation between 2 to 5 years. Members ultimately achieved consensus that 3 years would achieve a balance between the need for sufficient frequency to correct issues in a timely manner and providing enough time for the evaluation to be practicable and incorporate multiple years of performance information.

Committee members briefly discussed the proposed requirement for operators to analyze leak detection tool selection in § 192.763(a)(1)(iii). Members generally agreed that compliance the GPAC-recommended ALDP performance standard discussed previously (see section III.D) was sufficient to establish that leak detection equipment. During the discussion, members described how such an analysis should include validation of tool performance either by the operator or the equipment manufacturer. However, members were unclear on what else PHMSA expected from this analysis and how it differed from the requirements defined in the performance standard or the periodic performance standard. Members representing operators and two States were particularly concerned about how smaller operators would implement this requirement beyond documenting compliance with the performance standard. One member representing an operator highlighted public comments made during the Committee proceedings regarding the requirement to define leak survey frequencies but did not suggest a change to the recommendation.

Finally, regarding the use of human senses for gas pipeline leak surveys, the GPAC quickly reached consensus on a proposal from a member representing the public to remove the proposed allowance to use human senses for leak surveys of gas transmission and gathering lines in Class 1 and Class 2 locations with notification to PHMSA in proposed § 192.706(a)(2) but clarify that an operator may use human senses to supplement leak survey methods that meet the performance standards previously recommended. While members noted that observing bubbles or other visual indications can be effective for identifying leaks from offshore pipelines, they agreed that the previously discussed performance standards were appropriate for identifying leaks from onshore pipelines where the visual indications of a leak were less conspicuous.

4. GPAC Recommendation

The Committee unanimously made the following recommendations on PHMSA's proposed ALDP elements:

- "The committee recognizes that periodic evaluation and continuous improvement is necessary and recommends PHMSA consider requiring an operator conduct an evaluation every 3 years to ensure the adequacy of the leak detection program."
- "PHMSA should provide guidance on compliance with § 192.763(a)(1)(iii), with special attention for implementation by small operators."

The GPAC also unanimously recommended that PHMSA remove the proposed exception from leak detection equipment requirements for onshore Class 1 and Class 2 transmission and gathering lines proposed at § 192.706(a)(2).

Finally, the GPAC recommended that PHMSA clarify in § 192.763 that an operator may choose to use human senses as part of its ALDP suite of leak detection equipment and practices under § 192.763.

5. PHMSA Response

General

Regarding the general comments PHMSA received on the ALDP program requirements, while this final rule does not prescribe specific survey methods, technologies, or procedures, revisions PHMSA made to the performance standard described in section III.D and clarifications to the leak detection procedure requirements described below are designed to help ensure that operators use methods and equipment that are effective and efficient for the type of pipeline facility and its operating environment. These requirements are essential to meeting the mandate from Congress that operators use advanced leak detection technologies that can reliably detect leaks that pose a potential hazard to public safety and the environment. Regarding whether compliance with § 192.763 satisfies the requirement to have an "effective leak management program" under DIMP, the ALDP requirements at § 192.763 cover only the first part of leak management—initial identification—and that response and management of leaks are addressed at § 192.760. Additionally, there is still a role for the risk analysis framework under DIMP overlaid with the ALDP standards discussed here. For example, if an operator is using screening surveys based on a leak-rate criterion, an operator could still consider if additional measures are necessary to reliably detect leaks that pose potential hazards to public safety and the environment. While the performance standard for screening surveys of gas distribution lines reflects the capabilities of advanced mobile leak detection systems likely to be used on gas distribution lines, an operator should always consider if there are areas that justify additional preventative and mitigative measures, such as supplemental surveys, due to elevated risk to public safety or environmental factors that could affect the reliable detection of hazardous accumulations of gas from an aboveground screening survey.

Based on feedback from public commenters and from the Committee, PHMSA has struck proposed § 192.706(a)(2) from this final rule. This eliminated provision would have permitted operators to use human senses in lieu of leak detection equipment when performing leak surveys on onshore gathering lines or onshore transmission pipelines outside of an HCA in a Class 1 or Class 2 location with advance notification to PHMSA.

List of Leak Detection Equipment

This final rule retains the proposed requirement for an operator's ALDP to include a list of the leak detection equipment used in their ALDP. However, based on changes to the performance standard described in III.D, these requirements are simplified from those originally proposed in the NPRM. The NPRM established a performance standard for leak detection equipment in paragraph (a)(ii) in addition to the performance standard for leak detection programs in paragraph (b). Since the program performance standard has been eliminated in this final rule and the applicable leak detection equipment performance standard can now vary by system type and the leak detection technology or methods used, all references to requirements for the sensitivity of leak detection equipment have been relocated from the list of program elements to a dedicated paragraph on the performance standard for leak detection equipment in § 192.763(b). Specifics on the performance standard are described in section III.E. Also, as described in greater detail below, this final rule removes the requirement for operators to perform a documented analysis of commercially available leak detection technologies. Compared to the NPRM, this final rule simplifies the leak detection equipment portion of an operator's ALDP to simply require a list of leak detection equipment used by the operator. Requirements applicable to such equipment, such as the sensitivity for handheld leak detection equipment, have been relocated in this final rule to the requirements for leak detection equipment sensitivity at § 192.763(b).

This final rule adopts the unanimous GPAC recommendation to remove the allowance to permit human senses as the sole method for leak surveys of onshore gas transmission and regulated onshore gas gathering pipelines located in Class 1 and Class 2 locations with notification and approval from PHMSA. Since this proposal was originally at § 192.706, this amendment is described in greater detail in section III.B. Section 192.706 allows for the use of human senses for leak surveys of gas transmission lines and regulated gas gathering lines submerged beneath a body of water. In the NPRM, PHMSA proposed to only permit operators to use human senses when surveying submerged offshore pipelines; however, in this final rule, PHMSA has expanded this allowance to all submerged pipelines.

The GPAC also recommended that PHMSA provide additional guidance on its expectations for compliance with the leak detection technology selection analysis proposed at § 192.763(a)(1)(iii), but based on feedback from public comments, PHMSA is instead removing this requirement from this final rule. As originally proposed in the NPRM, operators would have been required to evaluate different types of technology for use on their pipeline system, including each example technology listed in the PIPES Act of 2020, and document that analysis. That analysis was intended to assess the appropriateness of different technologies based on the size, operating characteristics, operating environment, and configuration of the operator's system. However, PHMSA agrees with public comments that this proposed requirement was redundant with other proposed standards and creates an unnecessary analysis burden for operators. The performance standard PHMSA is finalizing in this rulemaking helps ensure that operators choose tools and procedures demonstrated to be effective for their system. Additionally, the proposed requirement to periodically evaluate the performance of an operator's ALDP at § 192.763(a)(4) has been retained in this final rule and addresses the need to identify shortcomings in operators' leak detection technologies and practices on an ongoing basis. As part of the periodic ALDP evaluation requirement, operators should consider the state of commercially available leak detection technology and whether new methods can enable an operator to perform more effective and efficient leak surveys. Considering these factors, removing the proposed technology evaluation requirement removes upfront compliance and documentation burdens with no meaningful impact on the performance of an operator's leak detection program. While the removal of this analysis, including the list of example methods at

§ 192.763(a)(1)(iii), addresses concerns about the listed methods, Removal of the 5-foot criterion from the equipment sensitivity standards described in III.D addresses comments concerned about the implied requirement to locate pipelines in advance of leak surveys.

Regarding the comments on methods of identifying leaks other than with leak detection equipment, such as meter tests, pressure tests, visible or auditory damage, and soap tests, this final rule clarifies that operators may supplement the use of leak detection equipment with these other methods, including human senses. These methods are described in greater detail in the discussion of the performance standard for leak detection equipment described in section III.D. This final rule explicitly allows operators to use soap testing as a method for performing leak surveys and pinpointing the origin of leak indications. PHMSA agrees that properly performed soap tests (i.e., applying a soapy solution directly to potential leak locations) is an effective means for locating even very small gas leaks. Finally, establishing minimum Federal standards for performing leak surveys at §§ 192.706, 192.723, and 192.763 does not prevent an operator from supplementing required leak surveys with other means for preventing and mitigating impacts to public safety.

Consistent with the direction from the PIPES Act of 2020 for PHMSA to adopt "performance standards" reflecting multiple types of commercially available advanced technologies, the NPRM and this final rule decline to limit which methods and technologies are permitted, provided they can achieve the revised performance standard described in section III.D. Therefore, while this final rule requires operators to use leak detection equipment and establishes standards of performance for leak detection methods, it does not require operators to use SCADA-based monitoring, mobile ground lab technologies, aerial surveys, continuous monitoring sensors, or any other specific method. In addition to satisfying the intent of the PIPES Act of 2020, defining a performance standard for leak detection equipment and methods rather than mandating specific methods better accommodates the fact that the technology for gas pipeline leak and rupture detection and methane gas monitoring is evolving rapidly.

PHMSA appreciates the concerns raised by commenters that setting one performance standard applicable to all survey methods and pipeline facility types was contrary to the goal of establishing technology-neutral standards and risked excluding effective and efficient survey methods. The changes PHMSA is finalizing in this rulemaking regarding the ALDP performance standards, as described in III.D, should address these concerns. Consistent with the PIPES Act of 2020, this final rule now includes different ALDP performance standards appropriate for the type and location of the pipeline and better reflecting the capabilities of remote sensing technologies, mobile and aerial surveys, and continuous monitoring sensors.

Leak Detection Procedures

In general, this final rule retains the proposed requirement for operators to document leak detection procedures (described in the NPRM as "leak detection practices"). PHMSA expects most operators will supplement or revise their existing procedures in their O&M and IM manuals to satisfy this requirement. Establishing and following procedures with parameters appropriate for the leak detection technologies and practices used by the operator is critical to reliably detect leaks, especially in challenging conditions. This requirement also addresses the findings from the

NTSB's investigation of a 2018 gas explosion involving failed leak surveys due to the operator's improper use of leak detection equipment (discussed in section II.H of the NPRM).[306]

In this final rule, PHMSA is providing additional specificity on the environmental and operational factors an operator's leak survey procedures must consider. These changes address public comments, accommodate the GPAC-recommended performance standards for screening surveys and traditional mobile surveys, and help ensure leak surveys reliably detect potential hazards to the environment. This final rule specifies that the environmental parameters an operator must define in its leak survey procedures include wind speed, ambient temperature, humidity, and weather-related factors that affect leak detection or gas migration. Similarly, this final rule also provides clearer requirements for the minimum operational parameters that an operator must define in its leak detection procedures, including the types of facilities for which the survey methods are effective, the effective ranges of the survey methods, and the minimum dwell time or maximum survey speed for mobile and aerial surveys necessary to achieve a reliable reading. These changes will help ensure that operators consider when and where specific survey methods are likely to be effective and provide greater clarity regarding how operators can comply with the requirement. As noted in public comments on the ALDP performance standard for leak detection equipment described in section III.D, the dwell time of equipment can affect the reliability of a leak survey if the operator fails to take it into account when developing their survey procedures. All else equal, a device with a faster response time can detect leaks with less

[306] National Transportation Safety Board. "Pipeline Accident Report: Atmos Energy Corporation Natural Gas-Fueled Explosion: Dallas, Texas: February 23, 2018." NTSB/PAR-21/01. Jan. 12, 2021. Washington, D.C. https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR2101.pdf.

dwell time or a faster survey speed compared with a device with a slower response time. Additionally, a faster response time could improve detection of intermittent sources.

These clarifications also address the concerns from comments PHMSA received related to the ALDP performance standard suggesting that PHMSA should prescribe minimum dwell times or required operational and environmental conditions in which operators would perform leak surveys. PHMSA did not propose specific requirements for dwell time or survey conditions in the NPRM with the understanding that each leak detection device and method would have its own requirements. Therefore, PHMSA did not adopt universally applicable specifications for dwell time or survey conditions in this final rule. However, PHMSA determined that requiring operators to define the limitations of leak detection technology and methods based on the equipment manufacturer's recommendations and the operator's knowledge of their system and operating environment addressees the need to consider such factors when selecting leak detection methods.

The GPAC recommended that PHMSA clarify that an operator may use human senses to supplement leak detection equipment. While this final rule does not include explicit regulatory language addressing this recommendation, nothing in the requirements of this final rule precludes an operator from supplementing its leak survey and investigation procedures with human senses or less-sensitive equipment, provided that the operator uses compliant leak detection equipment. Therefore, PHMSA determined that additional regulatory changes are not required to address the GPAC's recommendation on this issue. This final rule also removes reference to investigating leaks from § 192.763, since reference to both leak investigation and pinpointing the origin of leaks created confusion, and procedures and requirements for leak investigations are contained at § 192.760. While § 192.763 still requires operators to pinpoint the location of leaks following leak investigations, using different terminology should address some confusion and concerns certain commenters identified that the language implied that § 192.763 imposes technology requirements for leak response or leak grading procedures that preclude the use of effective leak investigation equipment used by first responders. Similarly, the revision avoids implying that operators are required to locate the source of a leak before establishing a high-priority grade or initiating other response activities to address risks to public safety.

In this final rule, PHMSA has revised and expanded the requirements for pinpointing leaks and performing follow-up investigations following screening surveys and other leak surveys to account for the adoption of a leak-rate performance standard for screening survey equipment and procedures and to address concerns raised on the performance of leak detection equipment. These are described in greater detail in section III.D, but revisions responsive to concerns about leak survey procedures are summarized below. Per this final rule, the standards for leak detection equipment can now vary based on pipeline type and survey method, and PHMSA has relocated the minimum sensitivity standard for equipment used for pinpointing and investigating leaks to § 192.763(a)(2)(ii). In addition to the proposed 5-ppm standard, this final rule, consistent with the GPAC recommendations on the topic, adds performance standards of 5 ppm-m for open-path devices and, for pipelines inside of buildings, a 1 percent LEL threshold rate (corresponding to 500 ppm for methane gas) for CGIs and similar equipment commonly used inside of buildings and other potentially hazardous environments. Additionally, this final rule clarifies that operators can also apply a soap solution for pinpointing the location of a leak on exposed pipelines.

Similarly, since this final rule formalizes a performance standard for screening survey equipment and procedures with the leak-rate criteria, this final rule also creates an explicit requirement for operators to perform follow-up investigations of indications of leaks that exceed the required detection limits defined at §§ 192.763(b)(1)(i) and (b)(2)(i) for such screening surveys. As such, an operator must prioritize follow-up investigations of indications of potential hazards to public safety and the environment. Potential public safety factors an operator should consider as a part of this prioritization include the number and proximity of nearby structures, HCA or moderate-consequence area[307] status (for gas transmission pipelines only), and the presence of wall-to-wall pavement. Factors an operator should consider when prioritizing environmental harm include, at a minimum, the estimated or measured release rate of gas.

This final rule retains requirements for operators to have and follow procedures for maintaining and calibrating leak detection equipment and associated recordkeeping, which will help ensure operators will reliably achieve the required detection limits and detect potentially hazardous leaks.

Leakage Survey Frequency

PHMSA did not intend for the leak survey frequency program element to require surveys more frequently than specified at §§ 192.9, 192.706, and 192.723; however, operators may need

[307] See definition in § 192.3.

to perform more frequent surveys to comply with the ALDP performance standard described in section III.D or because the operator determined it was a necessary measure under the section 114 self-executing mandate, its IM program, or other evaluations. PHMSA has determined that the performance standard for leak survey equipment and procedures itself is sufficient to achieve this objective without listing survey frequency as a program element and creating potential confusion. Therefore, PHMSA has revised this final rule by removing the survey frequency as a required ALDP program element, which should reduce uncertainty and the burden of repeating specified procedures within an operator ALDP.

While survey frequency has been removed as an ALDP program element, certain requirements within this final rule may still require operators to perform more frequent leak surveys, particularly leak surveys using flow-rate standards (see section III.D). For example, if an operator's screening survey procedure requires multiple passes in a survey vehicle to achieve the minimum detection limit and probability of detection specified by § 192.763(b), then the compliance survey is only complete when the operator performs all the surveys necessary for the method to meet the performance standard for leak surveys. When PHMSA evaluates whether an operator's request to use an alternative performance standard for leak surveys under § 192.763(d) that achieves an equivalent level of public safety and environmental protection, the frequency of the leak survey will be an important factor for consideration since leak survey frequency directly impacts the timing of detection and repair, and therefore exposure to pipeline safety risk and total emissions.

Periodic Evaluation and Improvement

This final rule retains the proposed requirement for operators to periodically evaluate the performance of their ALDP. Periodic evaluation is necessary for an operator to help ensure that their ALDP reliably detects all grade 1 and grade 2 leaks and to implement any changes necessary to address potential shortcomings. This evaluation is particularly important when an operator is using the leak rate performance standard for leak detection equipment at §§ 192.763(b)(1)(i) and (b)(2)(i) to help ensure that operators are reliably detecting leaks exceeding the leak-rate criterion with a 90 percent probability of detection. This requirement is similar in principle to the existing continuous improvement requirements under the IM requirements in subparts O and P of part 192 as well as requirements for certain operators to periodically review procedures within their operational manuals in accordance with §§ 192.605(b)(8) and (c)(4). However, PHMSA was persuaded by public comments that the proposed annual reevaluation interval for reviewing an operator's ALDP increases costs without providing commensurate benefits. Therefore, this final rule adopts a 3-year revaluation interval as recommended by the GPAC and that corresponds to the leak survey frequency generally applicable to outdoor gas distribution pipelines, ensuring that operators will survey most outdoor pipelines since the last program evaluation. This revised interval will also enable operators to evaluate a more complete set of information on the performance of their leak survey program while significantly reducing the average annual cost.

This requirement helps ensure operators periodically evaluate ways to improve their leak detection programs based on leak detection performance data and advances in technology. For example, if an operator finds evidence that their leak surveys fail to detect leaks, fail to reliably find grade 1 and grade 2 leaks, or are not detecting leaks exceeding the performance standard for leak surveys, the operator may have to make changes to its ALDP elements to ensure the minimum performance standard at § 192.763(b) is met. This provision offers potential environmental benefits and could also result in cost savings to operators by helping further reduce product losses from pipeline facilities. PHMSA disagrees with industry comments submitted after the GPAC meeting that section 113 of the PIPES Act of 2020 permits PHMSA to require operators evaluate changes to the ALDP based only on changes to the facility itself. The factors for consideration specifically address measuring whether the operator's leak detection program is meeting the applicable performance standard and reliably detecting leaks that are potentially hazardous to people, property, and the environment. Additionally, since this final rule removed the proposed requirement for operators to initially evaluate different leak detection technologies, ongoing consideration of the advances in commercially available leak detection technologies is no longer duplicative.

Regarding evaluations operators perform in accordance with the existing DIMP requirements, DIMP is broader than leak surveys and does not include specific performance standards for leak detection equipment that this requirement addresses. However, to the extent that an operator's evaluation in accordance with DIMP accomplishes the requirements of both this section and subpart P of part 192, an operator could use that analysis for both purposes.

Recordkeeping

Generally, this rulemaking finalizes the proposed recordkeeping requirements from the NPRM. However, in finalizing a simplified performance standard for leak detection equipment in this rulemaking, PHMSA has eliminated the recordkeeping requirement for validating the performance of the program, addressing the concern raised in comments from the Industry Trades. The remaining recordkeeping requirements in this final rule include the retention of records of calibration, records of failures of leak detection equipment for 5 years after the date of the failure, and records validating that each model of leak detection equipment meets the performance standard, which must similarly be maintained for 5 years. These records are essential to help ensure that leak detection equipment meets the performance standard of this final rule and continues to perform reliably while in service. Five years corresponds to the typical PHMSA inspection cycle and is therefore the minimum frequency necessary to demonstrate compliance with these requirements upon inspection. As discussed earlier with listed leak detection equipment, this final rule clarifies that records documenting that the performance of leak detection equipment has been validated by the manufacturer satisfies this recordkeeping requirement.

F. Procedure Manuals, Sec. 114 Implementation for Gas Pipelines, LNG Facilities, and UNGS Facilities—§§ 192.12, 192.605, 193.2503, and 193.2605

1. Summary of PHMSA's Proposal

In section 114 of the PIPES Act of 2020, Congress directed all operators of pipeline facilities to update their procedures to address the new elements added to 49 U.S.C. 60108(a), including: eliminating hazardous leaks of natural gas and any other flammable, toxic, or corrosive gas; minimizing releases of natural gas; and replacing or remediating pipelines known to leak based on their material (including cast iron, unprotected steel, wrought iron, and historic plastics with known issues), design, or past O&M history.

In the NPRM, PHMSA proposed to codify this self-executing statutory directive for gas pipeline operators by amending the procedure manual requirements at § 192.605 consistent with the statutory language in section 114 of the PIPES Act of 2020 and to require operators of gas transmission, distribution, offshore gathering, and Types A, B, and C onshore gathering pipelines to update their procedures to provide for "eliminating leaks and minimizing releases of gas from pipelines, as well as remediating or replacing pipelines known to leak based on their material, design, or past O&M history." The NPRM explained that pipe materials known to leak included cast iron, unprotected steel, wrought iron, and historic plastics with known issues (such as, in the case of distribution systems, low-ductile inner wall "Aldyl A" piping manufactured by Dupont before 1973, polyethylene gas pipe made from PE 3306 resin, Delrin insert tap tees, and caps made of Celcon (polyactal) on Plexco service tees).[308] Further, in determining whether a particular plastic pipe material is a "historic plastic with known issues," operators should consider published materials identifying systemic integrity issues on plastic pipe such as PHMSA advisory bulletins and similar guidance, PHMSA and State regulatory actions, PHMSA pipeline failure investigation reports, NTSB reports, industry technical resources, and the operator's own

[308] 88 FR 31890 at 31927.

design experience and operating and maintenance history. The proposal regarding "minimizing releases of gas" is discussed further in section III.M of this final rule.

PHMSA proposed similar requirements at § 192.12 for UNGSF operators and at §§ 193.2503 and 193.2605 for LNG facility operators to update their manuals to contain procedures for eliminating leaks and minimizing releases of gas. PHMSA also requested public comments on whether to explicitly require UNGSF and LNG operators to include in their manuals procedures for remediating or replacing pipelines known to leak based on their material, design, or past O&M history. In particular, PHMSA requested input on the potential safety and environmental benefits and potential costs of a particular approach, including whether that approach would be technically feasible, cost-effective, and practicable. The proposals regarding LNG facilities and minimizing releases of natural gas are discussed further in sections III.C and III.M.

2. Summary of Public Comments

Several commenters, including NAPSR and the PST, supported the proposed procedure manual requirements at § 192.605. The MD Attorney General et al. said that proposed revisions at § 192.605 "would support PHMSA's cooperation with States undertaking inspection and enforcement activity in connection with" section 114 of the PIPES Act of 2020. The PST and the Industry Trades supported PHMSA's effort to clarify that section 114 of the PIPES Act of 2020 is applicable to Type B and Type C gathering lines.

Atmos Energy Corporation and the Industry Trades argued that PHMSA's revisions should not require operators to create procedures for eliminating all leaks, since section 114 of the PIPES Act of 2020 refers only to the elimination of "hazardous leaks." Both sets of commenters provided alternative regulatory text, with Atmos suggesting that § 192.605(b)(13) should instead refer to "eliminating hazardous leaks," and the Industry Trades suggesting that PHMSA should revise the phrase to "eliminating leaks in accordance with leak repair schedules specified in § 192.760."

The GPTC commented that PHMSA should remove the requirement for operators to remediate or replace pipelines known to leak based on their material, design, or past O&M history from the final rule because they believe there are other areas of the regulations that would address such issues: namely, §§ 192.613(b), 192.703(b), and 192.1007(d). Atmos Energy Corporation provided a similar comment but did not specify which sections of subparts M, O, and P it saw as redundant with proposed §§ 192.605(b)(13). The GPTC further claimed that the proposed change would create the need for a risk management program for all pipelines based solely on emissions reduction. Oleksa and Associates, Inc. suggested PHMSA revisit the regulations to mandate pipe replacement within a few years based on industry progress, reasoning that the decline in methane emissions referenced in the NPRM[309] occurred "voluntarily, without any change in the PHMSA regulations or in the GPTC Guide."

Kinder Morgan, Inc. commented that PHMSA should either provide an exemption for "de minimis" leaks at § 192.12(c) for UNGSFs or remove the proposal to eliminate all leaks on UNGSFs from the final rule entirely, noting that downhole repairs can be very costly and providing data to that point. Kinder Morgan, Inc. also asserted that the normal operation of

[309] See 88 FR 31890 at p. 31902.

storage wells will result in small leaks, and that it is not cost-effective for operators to eliminate small, non-hazardous leaks or to replace valves or other components.

3. GPAC Deliberation Summary

GPAC discussion of NPRM proposals relative to the procedure manuals occurred on November 27, 2023. PHMSA presented on preexisting requirements at § 192.605(c) for operators to have and follow procedure manuals for gas transmission pipelines, gas distribution pipelines, offshore gas gathering pipelines, and Type A gas gathering pipelines and § 192.12(c) for UNGSF. PHMSA also explained the proposals to revise § 192.605 and § 192.12 to address the mandate in section 114 of the PIPES Act of 2020 regarding operators eliminating leaks and minimizing releases of natural gas. PHMSA also provided an overview of received comments on the proposal, including some comments that were supportive of the proposed requirements and suggestions that the word "reduce" be used in place of "minimize." PHMSA concluded its presentation on the topic by noting that the proposals at § 192.605 codified requirements from section 114 of the PIPES Act of 2020 and the term "minimize" is used in the statute. The GPAC then provided opportunities for stakeholders present at the meeting to present their feedback, which was taken by operators, representatives of large transmission pipeline operators, the gas gathering industry and publicly owned gas distribution utility trade associations. These commenters referenced their written comments and highlighted concerns regarding the proposals in this area. Several of the commenters highlighted concerns from the written comments regarding use of the phrase "minimize."

GPAC members then discussed PHMSA's proposed regulatory language. One industry Committee member expressed support for rulemaking to reduce methane emissions while trying to balance cost efficiency, practicability, and reasonableness. Although there was conversation amongst the members on the phrase "minimize," the focus on conversation was primarily relative to blowdowns as proposed in § 192.770 and design requirements for pressure relief and limiting devices in § 192.199, which are addressed in sections III.M and III.N.

4. GPAC Recommendation

The GPAC did not provide a specific recommendation on PHMSA's proposed revisions at §§ 192.12, 192.605, 193.2503, or 193.2605.

5. PHMSA Response

PHMSA appreciates the comments requesting PHMSA to clarify that the proposed amendments for operators to eliminate leaks are consistent with the language of Section 114 of the PIPES Act of 2020. For part 192-regulated gas pipelines, PHMSA intended for those procedures to reflect the leak grading and repair provisions being added at § 192.760, which would require operators to eliminate all hazardous leaks. Consistent with the withdrawal of the definition of the term "leak or hazardous leak" described in section III.R, PHMSA is specifying in this final rule at § 192.605 that operators' procedure manuals must provide for the elimination of leaks in accordance with the leak grading and repair requirements specified at § 192.760. Section 192.760 includes comprehensive standards for classifying and repairing leaks prioritized based on the likelihood and magnitude of harm to persons, property, and the environment; therefore, reference to generic requirements addressing "hazardous leaks" is no longer necessary.

PHMSA is similarly clarifying language at §§ 192.12(c) and 193.2605(b)(3) in this final rule to require operators of UNGSFs and LNG facilities, respectively, to have procedures for "eliminating leaks that represent an existing or probable hazard to public safety, property, or the environment." For LNG facilities, this includes, but is not limited to, having procedures for performing leak surveys in accordance with § 193.2624, which requires LNG operators to address leaks on LNG facilities while prioritizing leaks "based on the potential impact to persons, property, and the environment." PHMSA expects operators of UNGSF and LNG facilities have procedures and criteria for identifying, locating, and categorizing leaks that represent a potential hazard. However, unlike gas pipelines that will be subject to § 192.760, this final rule does not include prescriptive standards for such criteria for UNGSFs and LNG facilities. PHMSA did not receive comments on either the technical or economic feasibility of replacing pipelines known to leak in UNGSFs. As noted above, other LNG-specific proposals and the proposal related to operators eliminating leaks and minimizing releases of natural gas are discussed further in sections III.C and III.M.

PHMSA disagrees with commenters' suggestions that the proposed revisions at § 192.605 are duplicative with existing requirements in part 192. The specific code sections cited by commenters are not procedure manual requirements; to the extent the § 192.605 revisions relate to existing substantive requirements in subparts M, O, and P of part 192, the new requirements for operators to include such procedures in their manuals will reinforce and complement these existing requirements. While PHMSA applauds the efforts of industry to replace cast iron and cathodically-unprotected steel pipe, PHMSA believes that a prescriptive requirement, as mandated by Congress, is appropriate to address the impact of such pipe on emissions as evidenced by the GHGI data, which shows that cast iron pipe, representing less than 1 percent of gas distribution main miles, accounts for an estimated 20 percent of total fugitive emissions from all natural gas distribution mains. Additionally, requirements cited by the commenter, such as §§ 192.703(b) and 192.613(b), only address pipelines that have already been found to be in "unsatisfactory" or "unsafe" condition but do not address facilities that are prone to frequent leaks but have not already failed. Additionally, the requirement for an "effective leak management" program referenced under DIMP requirements in subpart P does not define standards for performance and is only applicable to gas distribution pipelines. Finally, none of the referenced requirements address minimizing intentional releases of gas associated with O&M tasks.

As specified in the final RIA, requiring operators to update their procedures to minimize the release of natural gas from their facilities is only incorporation of a self -executing mandate from Section 114 of the PIPES Act. Because these measures are mandated explicitly by the Act and are already in effect, PHMSA did not attribute the associated costs or benefits to the final rule.

G. Compressor Stations and LNG Facilities Subject to EPA Methane Emissions Monitoring Requirements—§§ 192.703(d) and 193.2624

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed an exemption for compressor stations subject to the EPA's regulations and, at the time, additional proposed methane emissions monitoring requirements at 40 CFR part 60, subparts OOOOa through OOOOc, from the proposed requirements for patrols, leak surveys, leak repairs, and ALDPs. PHMSA also clarified the OQ requirements for these facilities. Since the publication of PHMSA's NPRM, the EPA published its final rule titled "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" that finalized the amendments and additions it proposed at 40 CFR part 60, subparts OOOOa through OOOOc.[310]

With respect to LDAR requirements for facilities jurisdictional to PHMSA, these standards address fugitive emissions monitoring and repair for compressor stations on gas transmission and gas gathering pipelines constructed, reconstructed, or modified after September 18, 2015, but before December 6, 2022. The EPA final rule also issued (1) 40 CFR part 60, subpart OOOOb, that established emissions control standards for compressor stations (including gas transmission and gas gathering compressor stations and gathering boosting stations defined

[310] 89 FR 16820, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review," (Mar 8, 2024). EPA's website includes additional information on the final rule, including summaries, factsheets, and supporting analyses. https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-operations/epas-final-rule-oil-and-natural-gas.

per 40 CFR 60.5430b) installed, reconstructed, or modified after December 6, 2022; and (2) 40 CFR part 60, subpart OOOOc, that created nationwide emissions guidelines under the Clean Air Act applicable to states to follow in developing, submitting, and implementing state plans to establish performance standards to limit GHG emissions from existing sources (designated facilities) in the Crude Oil and Natural Gas source category.[311] The emissions requirements finalized in today's rulemaking cover existing compressor stations that are not otherwise subject to the EPA's 40 CFR part 60, subpart OOOOa through OOOOb regulations, as well as EPA-approved State and Tribal plans with standards at least as stringent as the EPA's emission guidelines in subpart OOOOc, or implemented through a Federal plan.

Among these emissions control standards, the EPA rules include requirements for methane fugitive emissions monitoring and leak repair. In order to avoid overlap with similar LDAR standards adopted by the EPA,[312] PHMSA proposed in its NPRM a narrow exception from some of its proposed requirements for gas transmission and gas gathering compressor stations that would be subject to monitoring and repair requirements within EPA's current and proposed regulations under 40 CFR part 60, subparts OOOOa through OOOOb, as well as EPA-approved State and Tribal plans with standards at least as stringent as the EPA's emission guidelines in subpart OOOOc, or implemented through a Federal plan.[313]

[311] Federally recognized Tribes have the opportunity, but not the obligation, to develop their own plans establishing standards for methane for existing sources on their Tribal lands. Tribes that choose to develop plans must follow the requirements for State plans.

[312] EPA specifically regulates fugitive emissions at well sites, centralized production facilities, and compressor stations in addition to equipment leaks at natural gas processing plants.

[313] Gas pipeline facilities that would be subject to this proposed exception remain PHMSA-jurisdictional gas pipeline facilities otherwise subject to parts 191 and 192 requirements and PHMSA regulatory oversight.

Specifically, PHMSA proposed this exception from each of its requirements pertaining to leak repairs (§ 192.703(c)), patrols and leak surveys (§§ 192.705 and 192.706), leak grading and repairs (§ 192.760), ALDPs (§ 192.763) and the qualification of leak detection personnel (§ 192.769). Operators would, notwithstanding the exception from other elements of § 192.760, be required to retain records associated with leak repairs pursuant to § 192.760(j). To establish clear boundaries, PHMSA also proposed the exception to cover those components located within the first block valve entering or exiting the compressor station facility (exclusive of that block valve), which marks the boundary of the station covered by the emergency shutdown system pursuant to § 192.167.

With regards to LNG facilities, as described in section III.C, PHMSA recognized the potential for conflicts with existing regulations and best practices in NFPA 59A and other standard practices. For LNG facilities, PHMSA did not propose in the NPRM a comprehensive, comprehensive LDAR program framework as discussed throughout this document for 192-regulated gas pipeline facilities, thus indirectly exempting LNG facilities through a limited regulatory scope.

2. Summary of Public Comments

Thermo Fisher Scientific and Project Canary, PBC, supported the proposed exemption and suggested it would minimize regulatory overlap and confusion while promoting improvements in public and environmental safety. The PST suggested that PHMSA should adopt the "more stringent" leak detection technology standard and leak grading and repair requirements combined with the EPA's more frequent quarterly leak survey requirement for compressor stations.

KOGA stated that the proposed requirements would impact operators by requiring additional equipment, resources, and training, and result in additional tracking requirements and procedures for operators. Enstor Gas, LLC and an individual commenter suggested the proposed provision be revised or otherwise placed under the specific code sections to which they would apply. Atmos Energy Corporation supported the proposed exclusion of facilities subject to EPA requirements but said that the current wording would subject operators to complying with overlapping and potentially conflicting EPA and PHMSA requirements, and that requiring operators to expend resources on temporary compliance with PHMSA regulations simultaneous with EPA requirements was unreasonable, and suggested revisions to the regulatory text at § 192.703(d).

GPA Midstream Association, et al., the Industry Trades, and INGAA requested the recordkeeping provision be removed from the exemption, reasoning that PHMSA cannot enforce EPA regulations and should not impose a separate, duplicative requirement.

The NGA supported the exemption, reasoning it minimized regulatory overlap, but suggested PHMSA expand the exemption to include distribution facilities covered by the EPA and State mandates. Similarly, GPA Midstream Association, et al., INGAA, and the Industry Trades suggested the exemption be clarified or expanded to apply to all EPA regulations, including State requirements that are pending U.S. approval, and suggested language to incorporate that provision into § 192.703(d).

Kinder Morgan, Inc. said that the NPRM's explanation of when the exception would apply was confusing and suggested PHMSA revise 49 CFR 192.703(d) to delay the compliance requirements until either the EPA's rule is abandoned, in which case 49 CFR part 192 would apply, or until the EPA's regulations at 40 CFR part 60, subpart OOOOa through OOOOc are finalized, and PHMSA's exception would take effect. The Industry Trades, the NGA, and INGAA suggested a 3-year effective date for all provisions of the final rule, reasoning it would minimize duplicative regulations by eliminating the need to establish procedures for and comply with PHMSA regulations in this rule temporarily, pending the effective date of the EPA requirements in the future. The commenters added that, if PHMSA proceeded as planned, it would need to clarify its approach and incorporate the cost of duplicative compliance into the final RIA.

The Industry Trades commented that PHMSA should consider exceptions for LNG facilities similar to what was proposed for gas transmission compressor stations subject to those same requirements, or other EPA, Federal, or State GHG emissions monitoring requirements, stating "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."[314]

[314] Industry Trades at 118 (PHMSA-2021-0039-26350).

3. GPAC Deliberation Summary

The GPAC did not recommend changes with respect to the proposed exemption in § 192.703 for LDAR requirements for gas transmission and gathering facilities subject to EPA emissions monitoring requirements. Members alluded to this exemption when discussing compliance timelines, addressing concerns with timing should PHMSA's final rule go into effect before the EPA's New Source Performance Standards and Emissions Guidelines subsequently finalized in 40 CFR part 60, subpart OOOOb and OOOOc, respectively. This concern is resolved in the discussion of compliance timelines in section III.U.

In discussions of leak surveys for LNG facilities, the GPAC voted that the proposed requirement was technically feasible, reasonable, cost-effective, and practicable if, among other changes discussed in further detail in section III.C, PHMSA exempted portions of LNG facilities subject to EPA emissions monitoring requirements from the leak survey requirement PHMSA proposed at § 193.2624. The requirements for LNG leak surveys, other than the exemption for facilities subject to emissions monitoring requirements, are discussed in section III.C.

4. GPAC Recommendation

The GPAC did not recommend changes to the proposed exemption for gas transmission and regulated gas gathering compressor stations as part of its recommendations regarding the technical feasibility, reasonableness, cost-effectiveness, and practicability of the requirements for gas transmission leak surveys and patrols (see section III.B), ALDP standards (see sections III.D and III.E), or leak grading, repair, and management (see sections III.H through J).

Regarding leak surveys for LNG facilities, the GPAC voted that the proposed requirements were technically feasible, reasonable, cost-effective, and practicable if, among other changes discussed in further detail in section III.C, PHMSA exempted portions of LNG facilities subject to EPA emissions monitoring requirements from the leak survey requirement PHMSA proposed at § 193.2624. The requirements for LNG leak surveys, other than the exception for facilities subject to EPA emissions monitoring requirements, are discussed in section III.C.

5. PHMSA Response

For gas transmission and regulated gas gathering compressor stations, this rulemaking finalizes the proposed exemption from the part 192 LDAR requirements with additional clarification to define the scope of the exemption more precisely. Since the OQ clarifications at § 192.769 have been withdrawn from this final rule, they do not need to be included in this exemption. See section III.K for additional discussion of that provision.

The EPA's fugitive emissions monitoring standards for compressor stations address similar requirements to those that PHMSA proposed in the NPRM. For example, the EPA emissions monitoring requirements establish minimum standards for the performance of leak detection programs and equipment, the frequency of leak surveys, and repair requirements when operators find leaks. Since compressor stations are covered by facility-specific EPA standards that already address methane LDAR, applying these requirements in this final rule is not necessary. Since the publication of PHMSA's NPRM, the EPA has finalized requirements for methane fugitive emissions monitoring and repair requirements that were originally proposed in the EPA's NPRM. Since these requirements are now final, PHMSA revised the reference in this final rule to emissions monitoring requirements at 40 CFR part 60, subparts OOOOa through OOOOc, with specific references to those EPA emissions monitoring requirements. Specifically, the exemption in today's final rule excludes from the monitoring and repair requirements of today's final rule facilities subject to methane fugitive emissions monitoring and repair requirements under:

- 40 CFR 60.5397a, including alternative means approved by the EPA under 40 CFR 60.5398a or 60.5399a;
- 40 CFR 60.5397b, including alternative means approved by the EPA under 40 CFR 60.5398b or 60.5399b; or
- An EPA-approved State plan, Tribal plan, or Federal plan that includes methane emissions monitoring and repair standards equivalent to the model standards at 40 CFR 60.5397c, including alternatives approved in accordance with 40 CFR 60.5398c.

PHMSA has determined that the EPA's emission standards and compliance schedules at 40 CFR part 60 subparts OOOOa through OOOOc for monitoring fugitive methane emissions from gas transmission and gas gathering compressor stations provide public safety and environmental protection on par with PHMSA's proposals in this final rule.[315] The EPA's

[315] 89 FR 16820. PHMSA considers the monitoring and repair elements of the EPA final rule to be at least as protective of public safety and the environment as corresponding existing requirements in 40 CFR part 60, subpart OOOOa.

regulations at 40 CFR 60.5397a(g)(2) within subpart OOOOa require quarterly[316] methane emissions monitoring surveys of leaks from gas transmission and gas gathering compressor stations—more frequent than PHMSA's leak survey requirements established in this final rule for all pipeline facilities except for those facilities in HCAs within Class 4 locations. The EPA's requirements require operators to perform leak surveys using leak detection equipment, either OGI or another "instrument" (such as FID) with a sensitivity of at least 500 ppm that complies with EPA Method 21 in Appendix A-7 to 40 CFR part 60. Those requirements and standards were similar to the leak detection equipment standards PHMSA contemplated in its NPRM; therefore, PHMSA has determined finalizing an exemption for those facilities from overlapping requirements in this rulemaking is prudent. The EPA's regulations require an operator first attempt to repair any leaks causing fugitive emissions detected during such a leak survey within 30 days and complete those repairs within 30 days of that first attempt, which is equivalent to the 30-day repair timeline PHMSA proposed in the NPRM for grade 2 gas transmission pipeline leaks in HCAs and Class 3 and Class 4 locations but more aggressive than PHMSA's proposed 6-month timeline for the repair of grade 2 leaks in non-HCA Class 1 and Class 2 locations. And

[316] There is a limited exception for a monitoring survey of the collection of fugitive emissions components at a compressor station located on the Alaskan North Slope, which must be conducted at least annually. While the final rule "Oil and Natural Gas Sector: Emissions Standards for New, Reconstructed, and Modified Sources Review," 85 FR 57018 (Sept. 14, 2020) removed all methane standards from 40 CFR part 60, subpart OOOOa, including the quarterly monitoring and repair requirements for methane fugitive emissions at compressor stations at 40 CFR 60.5397a(g)(2), Congress subsequently disapproved that final rule by a joint resolution (Pub. L. 117-23) enacted pursuant to the Congressional Review Act (Pub. L 104-121). The president signed that joint resolution into law. As a result, the EPA's September 2020 final rule is treated as if it had never taken effect, and the methane standards in subpart OOOOa promogulated in 2016 remain in effect. See EPA's Q&A for more information. https://www.epa.gov/system/files/documents/2021-07/qa_cra_for_2020_oil_and_gas_policy_rule.6.30.2021.pdf.

although the EPA's repair timelines may be less demanding than those adopted in this final rule for grade 1 leaks, the EPA's more frequent survey interval would help ensure operators detect and remediate leaks on gas transmission and gas gathering compressor stations in a timely manner. Further, allowing operators to direct their compliance efforts toward the EPA's regulatory regime rather than overlaying additional, similar requirements from PHMSA for EPA-regulated facilities helps ensure that operator resources are focused on addressing public safety risks and reducing methane emissions rather than navigating and implementing overlapping regulatory frameworks.

Based on public comments and the GPAC discussion, this final rule provides additional detail with respect to facilities covered by State and Tribal plans approved by the EPA in accordance with 40 CFR part 60, subparts OOOOc and Ba[317]. PHMSA appreciates the concerns raised by commenters regarding the applicability of the NPRM to facilities covered by State plans that are pending review by the EPA. Therefore, PHMSA is finalizing in this rule the 3-year compliance deadline recommended by the Committee and public comments. This compliance timeline extends beyond the implementation timelines for the EPA's Federal emissions monitoring requirements at 40 CFR part 60, subpart OOOOa through OOOOb, and the submission and approval deadlines for State and Tribal plans under 40 CFR part 60, subpart OOOOc, and should therefore address the concerns raised by public commenters and the

[317] 40 CFR part 60, subpart Ba, applies to EPA's final Emission Guidelines. On November 17, 2023, the EPA issued final updates to the EPA's ''Implementing Regulations'' under section 111(d) of the Clean Air Act (88 FR 80480).

Committee recommendation. See section III.U for additional information on general compliance timelines.

This final rule similarly makes revisions to the scope described in §§ 192.703(d)(2) and (d)(3) to describe the scope of the exemption more precisely and eliminate unnecessary duplication. The revised language more clearly identifies the first block valves entering and existing the compressor station and clarifies that the valves themselves may be included in the scope of the exemption, provided they are subject to emissions monitoring requirements in EPA standards in 40 CFR part 60, subparts OOOOa and OOOOb or emissions monitoring requirements in a Federal plan or EPA-approved State or Tribal plan with standards at least as stringent as the EPA's emission guidelines in subpart OOOOc per 49 CFR 192.703(d)(1). Additionally, while the proposal identified valves covered by the compressor station emergency shutdown system, this final rule allows an operator to instead identify valves covered by station overpressure protection for facilities where an emergency shutdown system is not present. Finally, since recordkeeping requirements in 49 CFR 192.760 are not exempted in the introductory text of 49 CFR 192.760(d), referencing recordkeeping as an eligibility criterion was unnecessary. While 49 CFR 192.703(d)(3) has therefore been removed, operators must still make and retain records in accordance with 49 CFR 192.760(j).

The final rule therefore does not impose marginal costs or benefits on operators of compressor stations covered by EPA emissions monitoring requirements, or a State, Tribal, or Federal plan that meets the exemption criteria. While the final rule requires operators to maintain repair records, this is an existing recordkeeping requirement and therefore does not impose a marginal increase in costs above baseline compliance. Section 2.2.14 of the RIA describes an alternative where PHMSA does not adopt the proposed exception for facilities covered by EPA methane emissions monitoring requirement. This would result in increased costs for operators of compressor stations from applying two leak detection and repair schemes to facilities within compressor stations. PHMSA determined that this alternative results in increased costs to operators from implementing partially redundant sets of regulatory requirements with little additional benefit.

The Committee and comments from the Industry Trades recommended PHMSA consider a similar exemption for LNG facilities from the proposed leak survey requirements in § 193.2624 of the NPRM. While LNG facilities are not explicitly referenced in the scope of the EPA emissions monitoring requirements at 40 CFR part 60, subparts OOOOa through OOOOc, in the same way that gas transmission compressor stations are, some LNG facilities or portions of LNG facilities may be subject to EPA emissions monitoring if the facility is located within the production, processing, or transmission or storage segment and includes a "fugitive emissions component" and is therefore classified as a "fugitive emissions components affected facility."[318] PHMSA believes that if a portion of an LNG facility is classified as a fugitive emissions components affected facility subject to EPA (or State or Tribal) methane emissions monitoring requirements, it would most likely be due to the presence of a compressor. While other types of facilities, such as storage vessels, may be subject to certain requirements under the EPA rules,

[318] See 40 CFR 60.5365b(i) and EPA guidance at the following link. https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-operations/frequently-asked-questions-general#lng.

they are likely not subject to the EPA emissions monitoring and repair requirements in particular that mirror the proposed leak survey and repair standards that PHMSA proposed in the NPRM and finalized in this rulemaking.[319] PHMSA agrees with commenters that it is not necessary to duplicate requirements for leak surveys and patrols if the EPA has already established similar facility-specific standards. PHMSA has therefore adopted an exemption in this final rule for certain components or portions of LNG facilities as well. The proposed quarterly leak survey frequency PHMSA proposed in the NPRM was intended to generally mirror the monitoring frequency from the now-finalized EPA emissions monitoring requirements,[320] and the EPA regulations include more prescriptive standards for repairing leaks compared to PHMSA's proposed requirement to repair leaks in accordance with an operator's O&M procedures.[321] Additionally, PHMSA has revised, in this final rule, the leak detection equipment sensitivity requirements for LNG facilities to be more consistent with the EPA's emissions monitoring requirements (see section III.C for additional discussion of these changes). Because the EPA's requirements are generally equivalent to, or more stringent than, the requirements PHMSA is finalizing in this rulemaking, exempting those portions of LNG facilities that are subject to the EPA's emissions monitoring requirements from PHMSA's leak survey and repair requirements

[319] Operators should nonetheless verify whether these or any other EPA requirements apply to their facilities, including storage vessels and other types of facilities.

[320] For example, final 40 CFR 60.5397b(g)(1)(v) requires a monitoring survey at least monthly using audible, visual, and olfactory detection methods or any other detection method, and quarterly monitoring survey using optical gas imaging or EPA Method 21.

[321] EPA repair requirements for emissions monitoring for compressors are defined at 40 CFR 60.5397a(h), 40 CFR 60.5397b(h), and the emissions guidelines include model repair standards at 40 CFR 60.5397c(h)

will reduce the costs of duplicative or contradictory compliance efforts without compromising public safety or protection of the environment.

Different from PHMSA's exemption for compressor stations on gas transmission and regulated gas gathering lines, for an operator of an LNG facility to be exempt from the leak survey and repair requirements of this final rule, the operator is required to provide documentation that a portion of their LNG facility is subject to the EPA's emission monitoring requirements and document which components or portions of the LNG facility are subject to the EPA's requirements in accordance with 49 CFR 193.2639(d). This additional information is necessary because, compared to the EPA's standards for compressor stations on gas transmission and gas gathering lines, the applicability of the EPA's emissions monitoring requirements within compressor stations at LNG facilities are defined differently. This information will help ensure that there are no gaps in Federal oversight over fugitive emission reductions within LNG facilities. Not all LNG facilities or portions thereof are likely to be classified as compressor-affected facilities, and that the EPA emissions monitoring standards do not apply to compressors on gas distribution systems, including LNG facilities downstream of what the EPA defines as the "local distribution company custody transfer station," commonly known as a city gate station. The EPA defines the term "local distribution company custody transfer station" as a metering station where the local distribution company receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines.[322] The EPA

[322] 40 CFR 60.5430a, 60.5430b, and 60.5430c.

definitions in 40 CFR 60.5430 for "natural gas transmission" and "local distribution company custody transfer station" may not align with the terms "gas transmission line" and "distribution center" used for similar facilities in 49 CFR part 192 in all circumstances.

For both gas transmission and LNG facilities, this final rule continues to require operators maintain records of repairs made. Repair records are necessary for operators to have knowledge of their pipeline facility, which informs risk-based programs such as integrity management. This information helps ensure appropriate documentation of change and trend analysis on those facilities as well as adequate documentation to support regulatory oversight activity by pertinent State and Federal regulatory authorities. Recordkeeping requirements for leak repairs on gas transmission and regulated gas gathering lines in § 192.760(j) have been revised in this final rule to reference existing retention schedules defined in § 192.709. This change requires operators retain, for 5 years, records of repairs of non-pipe components. See section III.J for additional discussion of the recordkeeping requirements for leaks and repairs.

H. Leak Grade Definitions—§§ 192.3 and 192.760

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to replace the general requirement for operators to repair all hazardous leaks in § 192.703 with a comprehensive grading scheme in § 192.760 applicable to all part 192-regulated gas pipeline operators. The purpose of this proposed change was to help ensure that operators grade and repair all leaks on a schedule for each leak grade based on the severity of a given leak's public safety and environmental risks.[323] The NPRM included a leak-grading framework informed by the criteria of the GPTC Guide—which is familiar to pipeline operators and State enforcement personnel—to facilitate compliance and regulatory oversight. To support these proposed criteria, PHMSA included in the NPRM proposed definitions for the term "leak or hazardous leak" and various terms that appear in the grading criteria, including "confined space," "gas-associated substructure," "lower explosive limit (LEL)," "substructure," "tunnel," and "wall-to-wall paved area." See section III.R for further details on the proposed definition for "leak or hazardous leak."

PHMSA proposed to define a "confined space" as any subsurface structure, other than a building, of sufficient size to accommodate a person, and in which gas could accumulate or migrate. These would include vaults, catch basins, and manholes. As noted in the NPRM, the proposed definition was consistent with a similar term in the GPTC Guide but differed from the definition of a "confined space" used by OSHA at 29 CFR 1910.146(b).

PHMSA proposed to define a "substructure" as any subsurface structure that is not large enough for a person to enter and in which gas could accumulate or migrate. Substructures would include telephone and electrical service boxes and associated ducts and conduits, valve boxes, and meter boxes. Correspondingly, PHMSA proposed to define a "gas-associated substructure"

[323] These grading requirements apply to all commodities transported under part 192, including petroleum gas, as all non-natural gas commodities covered under part 192 are hazardous to human health or the environment. See § 192.3 (definition of gas). Petroleum gas systems are subject to some specialized grading criteria due to the unique hazards posed by this heavier-than-air gas.

as a substructure that is part of an operator's pipeline facility but that is not itself designed to convey or store gas.

PHMSA proposed to define the "lower explosive limit (LEL)" as the minimum concentration of vapor in air below which propagation of a flame does not occur in the presence of an ignition source at ambient temperature and pressure. The proposed definition specified an LEL of natural gas of 5 percent methane in air by volume, an LEL for propane of 2.1 percent propane in air by volume, and an LEL for hydrogen of 4 percent hydrogen by volume.

PHMSA proposed to define a "tunnel" as a subsurface passageway large enough for a person to enter and in which gas could accumulate or migrate. Compared with a confined space, a tunnel is intended for regular or occasional human occupancy.

PHMSA proposed to define a "wall-to-wall paved area" as an area where the ground surface between the curb of a paved street and the front wall of a building is continuously paved with hard top surface impermeable to gas, excluding non-continuous landscaping such as tree plots.

See section III.R for further details on the proposed definition for "leak or hazardous leak."

The proposed leak grading criteria in § 192.760 would require operators to classify every leak on any portion of a gas pipeline, including components such as flanges, meters, regulators, and ILI launchers and receivers, as either, in order of decreasing priority, grade 1, grade 2, or grade 3, based on the magnitude and probability of risks posed by that leak to the public and the environment. Operators would be required to prioritize remediating leaks representing the most serious hazards to people or the environment and meet minimum repair timelines for each grade. Operators would also be obliged to immediately and continuously investigate each leak discovered on their pipelines until determining the leak grade to help ensure quick identification and prompt remediation of high-risk leaks. In the NPRM, PHMSA also included several enhancements to the GPTC Guide's three-tiered framework to address gaps PHMSA identified in safety and environmental protection, including the establishment of repair deadlines for grade 3 leaks and incentivizing operators to replace or remediate pipes known to leak.

Grade 1 Leaks—§ 192.760(b)

In the GPTC Guide and in the leak-grading framework PHMSA proposed in the NPRM, a grade 1 leak is the highest-priority grade. The NPRM described a grade 1 leak as one that represents an existing or probable hazard to persons, property (consistent with the description in the GPTC Guide), or an existing, grave hazard to the environment. A grade 1 leak presents an urgent or emergency situation—for this reason, PHMSA proposed that operators must take "immediate and continuous" action to eliminate the hazards posed by grade 1 leaks to public safety and the environment. To define leaks that present an existing or probable future hazard to public safety and releases of sufficient volume that pose a grave hazard to the environment, the proposed grade 1 leak criteria defined that, at a minimum,[324] a grade 1 leak included any of the following characteristics:

[324] Operators may decide to adopt additional grade 1 criteria and grade 2 criteria supplementing the required criteria of the final rule.

- Any leak that, in the judgment of operating personnel at the scene, is of sufficient magnitude to be an existing or probable hazard to persons or property, or a grave hazard to the environment;
- Any amount of escaping gas that has ignited;
- Any indication that gas has migrated into a building, under a building, or into a tunnel;
- Any reading of gas at the outside wall of a building or areas where gas is likely to migrate to an outside wall of a building;
- Any reading of 80 percent or greater of the LEL in a confined space;[325]
- Any reading of 80 percent or greater of the LEL in a substructure (including both gas-associated substructures and other substructures), from which gas would likely migrate to the outside wall of a building;
- Any leak that can be seen, heard, or felt by human senses; or
- Any leak reportable as an incident as that term is defined in § 191.3.

The grade 1 leak criteria PHMSA proposed in the NPRM resembled similar criteria in the GPTC Guide and, consistent with the framework of that guide, were intended to require

[325] Several of the grading criteria reference gas readings and are expressed as percent of the lower explosive limit (LEL). The LEL is the minimum required concentration of gas necessary for the gas to ignite when exposed to an ignition source. Percent LEL measures how close measured gas concentration is to reaching a flammable atmosphere. The LEL of natural gas is 5% gas by volume. However, the LELs for other flammable gases vary (e.g., the LEL for hydrogen gas is 4% gas by volume). A reading of 100% or more of LEL indicates that a flammable atmosphere is present, provided there is a sufficient concentration of oxygen present to support combustion and the upper explosive limit (UEL) is not reached. The percent LEL is typically measured during a leak investigation with a combustible gas indicator.

operators prioritize those leaks that pose a significant hazard to people and property for immediate repair. However, PHMSA proposed differences from the GPTC Guide that were designed to address gaps PHMSA identified in safety and environmental protection. First, PHMSA proposed to characterize a grade 1 leak to include leaks with grave environmental harm by including leaks that could be "seen, heard, or felt" in § 192.760(b)(1)(vii). In comparison, Table 3a in the GPTC Guide limits the "seen, heard, or felt" criterion to leaks that are in a location that may endanger the public or property. This proposed change was intended to establish a simple criterion that could be quickly used by operator personnel on the scene to identify leaks that represent the greatest hazards to the environment in addition to leaks with likely hazards to public safety. Similarly, the NPRM proposed to classify any leak reportable as an incident under part 191 as a grade 1 leak, which would include any leak that resulted in total volume of unintended release of gas of 3 MMCF or more. Proposed § 192.760(b)(1)(vi) also classified a grade 1 leak as any reading of 80 percent LEL or greater in a substructure (subterranean structures too small for a human to enter) from which gas would likely migrate to the outside wall of a building. Unlike the GPTC Guide, the proposed criteria included substructures associated with the operator's gas pipeline. A gas-associated substructure includes facilities such as small valve boxes and other vaults not intended for human entry. In service of this proposal, PHMSA also proposed definitions for the terms "substructure," gas-associated substructure," and "confined space" in § 192.3 to facilitate operator compliance and PHMSA and State regulatory oversight.

Lastly, PHMSA proposed that any leak reportable as an incident under part 191 would be classified as a grade 1 leak. The definition of "incident" in § 191.3, as proposed in the NPRM, would include any event involving the release of gas from a pipeline that results in one or more of the following consequences: (1) A death, or personal injury necessitating in-patient hospitalization; (2) Estimated property damage of $129,300, excluding the cost of lost gas, (adjusted for inflation for calendar year 2022); or (3) Unintentional estimated gas release of 3 MMCF or more.

PHMSA intended this proposed criterion to address gaps in the GPTC Guide's current grade 1 leak criteria by helping to help ensure that operators repair leaks with very large release volumes or that are known to result in significant public safety and environmental harms but do not meet any of the other Grade 1 criteria. PHMSA views the "incident" criterion as a good proxy for determining whether a leak represents an "existing or probable hazard" and should receive a grade 1 classification, since a leak that causes significant safety and environmental consequences necessarily would have been an "existing or probable hazard" to persons and the environment at the time of detection.

As noted above, the NPRM proposed to apply the "seen, heard, or felt" criterion and the incident definition, which includes a total unintended release criterion of 3 MMCF or more per § 191.3, as criteria for defining leaks with grave environmental harm; however, PHMSA requested comments on whether to introduce other potential criteria for identifying grade 1 leaks subject to immediate repair due to the severity of environmental harm. Specifically, PHMSA requested comment on the utility of adopting a quantified emissions rate criteria for grade 1 leaks.

Grade 2 Leaks—§ 192.760(c)

Under the GPTC Guide framework and PHMSA's proposal, the grade 2 classification represents leaks that are not so urgent a hazard to public safety and the environment so as to require immediate and continuous action to eliminate the hazard but which nonetheless present public safety and environmental hazards significant enough to warrant timely repair.

PHMSA proposed to classify a grade 2 leak as any leak (other than a leak which qualifies as a grade 1 leak) with any of the following characteristics:

- A reading of 40 percent or greater of the LEL under a sidewalk in a wall-to-wall paved area;
- A reading of 100 percent of the LEL under a street in a wall-to-wall paved area;
- A reading between 20 and 80 percent of the LEL in a confined space;
- A reading less than 80 percent of the LEL in a substructure (other than gas-associated substructures) from which gas could migrate;
- A reading of 80 percent or greater of the LEL in a gas-associated substructure from which gas is not likely to migrate;
- Any reading greater than zero percent gas on a gas transmission or Type A or Type C gas gathering pipeline;
- Any leak with a leakage rate of 10 cubic foot per hour (CFH) or more;
- Any leak of LPG or hydrogen; or

- Any leak that, in the judgment of operator personnel at the scene, is of sufficient magnitude to justify scheduled repair within 6 months or less.

Compared to the criteria in the GPTC Guide, the grade 2 criteria PHMSA proposed in the NPRM included changes designed to address gaps in safety and environmental protection and improve enforceability. Specifically, the proposed grade 2 criteria did not include qualifying language from the GPTC Guide that PHMSA determined could be ambiguous or unenforceable. For example, in Table 3b of the GPTC Guide, any reading of 100 percent LEL or greater under a street in a wall-to-wall paved area "that has significant gas migration" that is not a grade 1 leak is considered a grade 2 leak; however, what constitutes "significant" gas migration is not defined or straightforward to enforce. Therefore, in the NPRM, PHMSA proposed to apply this standard to any concentration of gas at 100 percent LEL or greater, since such a concentration is hazardous to public safety with any amount of migration due to the risk of explosion. Similarly, PHMSA did not propose to condition criteria for grade 2 leaks in substructures on the likelihood that gas would likely migrate "creating a probable future hazard," as specified in Table 3b of the GPTC guide. Given the uncertainty of how likely gas migration would need to be to create a probable future hazard in a given situation, the NPRM instead proposed to define any reading of 80 percent or more of LEL in a substructure from which gas could migrate as a grade 2 leak.

Additionally, PHMSA proposed in the NPRM to add a new grade 2 criterion for all leaks from LPG systems that do not qualify as a grade 1 leak, consistent with an observation in the GPTC Guide that, since LPG is heavier than air and does not dissipate like natural gas, "few

[LPG] leaks can safely be classified as Grade 3."[326] Likewise, PHMSA proposed that grade 2 is the minimum priority grade for leaks of gaseous hydrogen, since hydrogen's lower LEL and lower auto-ignition temperature, compared to methane, increase the risk of explosion. Further information on the grading of hydrogen leaks is discussed in section III.Q.

To help ensure the timely repair of leaks that are hazardous to the environment, PHMSA proposed to include as a new grade 2 criterion any leak with an emissions rate equal to or greater than 10 SCFH. PHMSA requested public comment in the NPRM on the appropriateness of this criterion and the specific emissions rate proposed. PHMSA also requested comment on other criteria that might be appropriate for identifying leaks that pose sufficient hazard to the environment to justify a grade 2 repair timeline based on measured gas concentration, leak migration extent, or an operator's ranking of largest leaks. As an example, PHMSA described an approach employed by the Commonwealth of Massachusetts that categorizes methane leaks from natural gas pipelines as "environmentally significant" grade 3 leaks if they have a barhole reading of 50 percent gas in air or higher, or a measured leak migration extent[327] of 2,000 square feet or greater.[328] In Massachusetts, leaks with a migration extent from 2,000 to 10,000 square feet must be repaired within 2 years, and leaks with a migration extent greater than 10,000 square feet must be repaired within 12 months. The NPRM also requested comments on how quantification of emissions rates currently is, or could be, integrated into an operator's leak

[326] See Table 3 C in Appendix G-192-11A of the GPTC Guide.

[327] Leak migration extent means the area over which the released gas has migrated.

[328] 220 Code of Massachusetts Regulations (CMR) 114.07(1)(a).

survey, investigation, and management procedures, and whether other criteria could be used to identify leaks that present significant environmental risks.

PHMSA also proposed a minimum grade 2 classification for any leak on a gas transmission or Type A or Type C gathering pipeline, similar to criteria in the GPTC Guide, which requires a minimum of grade 2 classification for leaks on pipelines operating at 30 percent of SMYS or greater (i.e., most gas transmission lines) in Class 3 or Class 4 locations.

Grade 3 Leaks—§ 192.760(d)

PHMSA proposed that any leak that does not meet the criteria for a grade 1 or a grade 2 leak would be classified as a grade 3 leak, which would be the lowest-priority leak category. For illustration, the NPRM provided a non-exhaustive list of conditions that would indicate a grade 3 leak, including: a positive reading of less than 80 percent LEL in gas-associated substructures from which gas is unlikely to migrate, any positive reading under a street in an area without wall-to-wall pavement where gas is unlikely to migrate to the outside wall of nearby buildings, or a gas reading of less than 20 percent LEL in a confined space.

2. Summary of Public Comments

General

Multiple operators and the Industry Trades opposed PHMSA's proposed leak grading criteria to the extent it differed from the grading criteria within the GPTC Guide, in particular the addition of emissions rate measurements and other criteria targeted at environmental impacts. Multiple operators and the New York State Department of Public Service urged PHMSA rely on the existing GPTC leak grading guidance, which is used broadly throughout the industry, with certain operator commenters stating they have based their existing procedures off the GPTC Guide. The New York State Department of Public Service reasoned that PHMSA could still achieve the goal of having operators timely repair and eliminate all leaks by adopting the GPTC Guide leak grading requirements while introducing new grade 3 leak repair timelines and tightening grade 2 leak repair timelines.

Multiple industry representatives urged PHMSA to allow operators and State regulators to employ alternative leak classification systems. For example, Con Edison of New York commented that changing the grading criteria and terminology they use in New York would be "an extremely difficult change management undertaking," and recommended PHMSA allow State regulators to establish their own leak classification standards or alternatively adopt the system used in New York. Similarly, the NGA noted that existing State standards do not always align with the proposed grading definitions and noted that operators would have to revise procedures and retrain personnel.

NAPSR commented that PHMSA should take this opportunity to define leakage rate. The Industry Trades commented that the general requirements proposed for § 192.760 must provide flexibility for an operator to eliminate a leak through immediate and continuous action without first grading the leak. As written, the commenters asserted that § 192.760(a)(3) would require an operator to always determine a leak grade before a repair is made, which may unnecessarily delay the immediate repair of a leak and impede the mitigation of risk to public safety. The AGA noted that this rulemaking should focus on targeting the largest leaks and that using leak grade alone to target emission reductions is not an effective environmental strategy.

Comments related to the leak grading criteria as they apply to pipelines transporting hydrogen gas are described in section III.Q, and comments addressing the definition of the term "leak or hazardous leak" are addressed in section III.R. Comments on specific assumptions used in the PRIA are summarized and addressed in the RIA for this rulemaking, which is available in the docket.

Grade 1 Criteria

The PST and other commenters supported the proposed grade 1 leak criteria. However, multiple industry representatives urged PHMSA to clarify the proposed criteria, including by providing a clear distinction between a leak that poses an "existing or probable hazard" to persons and property and one that does not. NAPSR and multiple industry representatives urged PHMSA to clarify, define, or remove the phrase "grave hazard to the environment." For example, the Industry Trades stated that their understanding of the ordinary meaning of a "grave" environmental hazard would not include pipeline leakage, particularly from an individual leak. The GPTC and INGAA suggested that PHMSA use the existing GPTC Guide language, which does not include environmental hazards, and instead focuses on existing or probable hazards to public safety for grade 1 leaks and probable future hazards to public safety for grade 2 leaks.

Air Liquide Large Industries U.S. L.P. similarly recommended that PHMSA provide a quantitative definition for a grade 1 leak rather than the undefined term "grave hazard to the environment," which could "invite misinterpretation and misunderstanding by pipeline operators, regulatory agencies, and the general public."

Some commenters argued that the leak criteria PHMSA proposed could ultimately elevate every leak up to a grade 1 classification. The GPTC and other commenters noted that some of PHMSA's proposed changes could lead regulators to interpret any leak as a grade 1 leak, such as the use of the broad phrase "could migrate," since arguably any leak theoretically has the potential to migrate into a building, tunnel, etc., even if the probability of migration is extremely small. A trade association raised a similar concern that PHMSA using "could" in any grade 1 leak criterion would lead operators to prioritize lower-risk leaks at the expense of higher-risk leaks.

Multiple industry representatives opposed the "seen, heard, or felt" criterion PHMSA proposed in § 192.760(b)(1)(vii), commenting that grading a leak by "feel" is unsafe and that the criterion is too subjective to accurately assess the risk of a leak. The Industry Trades noted that the criteria for the classification of grade 1 leaks should not include human senses but should be determined by the use of instruments designed and calibrated to identify gas. Williams Companies, Inc. commented that the "heard" criterion would inadvertently pull in a common type of leak occurring on valves, operators, and other packing equipment that may be audible to personnel but typically has a relatively low leak rate. GPA Midstream Association, et al. added that this criterion could elevate many minor leaks to a grade 1 classification because even very small leaks can often be "heard." Commenters requested additional explanation for how this serves as a proxy for significant environmental or safety consequences. The GPTC commented that PHMSA should clarify that the criterion for leaks detectible by human senses does not include small leaks visible by bubbles in a water body or via a soap test.

Following the GPAC meeting, commenters such as Williams Companies, Inc. expressed support for a 100 kg/hr flow-rate criterion for grade 1 leaks as recommended by the GPAC. However, some commenters expressed concern with this criterion. For example, the April 2024 Industry Trades comment recommended that PHMSA explicitly exempt distribution operators from this grade 1 leak criterion to avoid forcing distribution operators to use flow-rate technologies to screen every leak on their systems even though members of the GPAC commented that leaks of such magnitude have never been detected on distribution pipelines.

Xcel Energy urged PHMSA to clarify that the proposed criteria in § 192.760(b)(iv), relating to gas readings at the outside wall of a building, applied to underground leaks only.

Grade 2 Criteria

The PST and other commenters supported PHMSA's proposed grade 2 leak criteria. Commenters, such as Picarro, Inc., specifically supported PHMSA including a flow-rate threshold in the grade 2 leak criteria but also suggested that requiring operators to perform more frequent leak surveys would have an even greater benefit.[329] Summit Utilities referenced research from GRI[330] and Washington State University[331] indicating that leaks on gas distribution lines with a flow rate greater than 10 SCFH represent between 2.2 percent and 20 percent of all leaks but between 56 percent and 80 percent of total emissions, both summarized in a 2023 article by Sean MacMullin and François-Xavier Rongére (affiliated with Picarro, Inc.

[329] See Section III.A for discussion of the frequency of gas distribution leakage surveys.

[330] Vol 2. EPA & Gas Research Institute, Methane Emissions from the Natural Gas Industry: Technical Report (June 1996).

[331] Lamb et al., Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States, 49 Environmental Science & Technology 5161 (Mar. 31, 2015).

and PG&E respectively) describing implementation of a "super emitter" LDAR program in a distribution system.[332]

INGAA commented that the description of Grade 2 leaks is confusing when comparing language in the NPRM and PRIA. NAPSR and multiple operators urged PHMSA to clarify the term "significant hazard to the environment." Others, including the Industry Trades, recommended that PHMSA remove this phrase from the introductory language at proposed § 192.760(c).

The NGA, the GPTC, multiple operators, and the Industry Trades opposed the proposed 10 SCFH leakage rate criterion. For example, commenters like the GPTC and the Industry Trades argued that flow rate-based technologies cannot accurately measure the flow rate of underground leaks without excavation, nor at elevated points on aboveground compressor station piping without using specialized equipment for access. The GPTC also expressed concern that, for some causes of leaks, flow rate can change over time in unpredictable ways. The GPTC and other commenters claimed that flow-rate measurement equipment can be unreliable due to site-specific conditions, does not provide instantaneous measurements, has estimated error rates in orders of magnitude, and may not be widely available. An operator requested PHMSA consider allowing operators to estimate flow rates based on other information rather than require direct measurement due to similar concerns about the availability of measurement equipment. Some operators also noted that crews sent to respond to odor calls and other first response activity may

[332] MacMullin, Sean, and François-Xavier Rongére, Measurement-based emissions assessment and reduction through accelerated detection and repair of large leaks in a gas distribution network, 17 Atmospheric Environment: X. 100201 (Jan 2023).

not be equipped with or trained on the proper use of emissions measurement equipment necessary to establish a grade if a flow rate standard is adopted. The Industry Trades further stated that direct measurement of actual leak rates would be time-consuming and burdensome, taking focus away from personnel for identifying and addressing a potential safety threat, and could even introduce new safety concerns for personnel attempting to size the leak rate. Other comments stated concerns about the cost and workload to measure emissions from existing and future leaks due to the cost of equipment, the number of such leaks, and the difficulty of measuring emissions rates from below-ground leaks.

Multiple industry trade associations and operators opposed adopting any flow-rate standard and noted a conflict between PHMSA requiring concentration-based leak detection equipment while using a leak-flow rate criterion for leak grading, since these two measurement approaches are not comparable or convertible. Multiple commenters, including a large municipally owned utility, argued that a leak-rate grading criteria has the effect of forcing an operator to select certain survey methods for compliance with the ALDP standards at § 192.763 despite PHMSA's goal of providing operators with flexibility in developing their ALDPs.

The Industry Trades and some gas pipeline operators recommended that PHMSA introduce a flexible grade 2 leak criterion for "environmentally significant" leaks, which have either a flow rate of 10 SCFH or greater, or a leak migration extent (the land area affected by gas migration) of 2,000 square feet or greater. These criteria would be similar to those adopted by the State of Massachusetts. [333] Industry commenters noted that operators should have the flexibility

[333] 88 FR 31890 at p. 31941.

to use alternative methods when determining "environmentally significant" leaks on their systems to allow operators to take into consideration their unique judgment, system knowledge, and availability of leak detection technologies. One alternative method suggested by commenters was the sum of barhole leak indication readings of percent gas-in-air using a combustible gas indicator. PPL Corporation also suggested that PHMSA establish a leak grading system that accounts for the age of the leak and its leak migration extent as an alternative. However, some commenters expressed concern with a leak migration extent approach. For example, the Joint Environmental comment cautioned PHMSA against adopting the leak migration extent method of the State of Massachusetts without first ensuring whether the method is appropriate across the country in locations with different soil moisture or soil textures, which could significantly alter gas migration patterns. These commenters also recommended that PHMSA only permit alternative methods for determining "environmentally significant" leaks through a process that requires affirmative PHMSA approval, rather than simple notification to PHMSA.

The Industry Trades further noted that 10 SCFH is an extremely small leak on a typical high-pressure gas transmission line. They provided example calculations estimating that a leak on a pipeline operating at 850 psig is approximately 55 times the volume of the same size leak on a pipeline operating at 1 psig, and that a leak on a pipeline operating at 60 psig is approximately 10 times the volume as the same size leak on a pipeline operating at 1 psig. NAPSR and a State pipeline safety agency suggested PHMSA adopt a flow-rate criterion of 20 SCFH or greater, as this is consistent with the design standards for excess flow valves (EFV). A gas transmission pipeline operator suggested PHMSA adopt a flow rate of 100 SCFH, as this would be consistent with EPA reporting requirements and, in their view, better represents a leak from a gas transmission line that presents a "significant potential harm to the environment." Following the GPAC meeting, commenters such as Williams Companies, Inc. expressed support for the 10 kg/hr threshold for grade 2 gas transmission leaks recommended by the Committee.

Minimum Grade 2 Classification on Certain Pipelines

The Industry Trades, INGAA, the TPA, the TCC, and multiple operators opposed the proposal to require operators grade leaks on transmission and Type A and Type C gathering lines as a grade 2 classification at a minimum. These commenters noted that leaks from such pipelines are not intrinsically more hazardous, and therefore, operators should be able to grade leaks as grade 3 leaks if those leaks do not meet the proposed grade 1 or grade 2 criteria. The TPA provided examples of leaks with low potential hazard and emissions that could justify a grade 3 determination, such as packing leaks on valves and other components, and argued that requiring accelerated repairs for these types of leaks could cause more emissions from blowdowns than it reduces from eliminating the repair on an accelerated timeline, which would increase costs and lead to more frequent service outages by limiting the ability of operators to schedule the repair of minor leaks with other maintenance activities.

LPG Systems

The Industry Trades commented that, notwithstanding the properties of LPG, PHMSA should not set a minimum grade 2 classification for LPG leaks, noting that "there is nothing precluding LP gas leaks from meeting grade 3 criteria in the GPTC guidance or any other existing literature." The Industry Trades and an operator recommended that PHMSA allow grade 3 classifications for LPG leaks either in general or at least for aboveground leaks.

Leak Grading Terms and Definitions

Industry trade associations, operators, and industry consultants opposed or expressed concern with the proposed rule's definition of "confined space" and differences from the definition used by OSHA and suggested aligning the definitions or using a different term to avoid confusion and duplicative terms in operators' procedure manuals. The Industry Trades recommended regulatory text that retained the GPTC Guide definition for "confined space" but used the term "enclosure" to differentiate the two concepts.

The Ohio Gas Association, operators, and others commented that the leak grading criteria should refer to percentage gas instead of percentage LEL, as the LEL depends on the exact gas composition and could vary between operators, unlike percentage gas. The Industry Trades also requested that PHMSA clarify if operators are required to determine the LEL for every atmospheric condition. RMI (formerly Rocky Mountain Institute) urged PHMSA to consider gas composition when determining the leak grades. KOGA requested PHMSA clarify whether the grade 2 criteria and repair requirements would retroactively apply to existing leaks. NAPSR requested that PHMSA clarify how the grading criteria would apply to toxic and corrosive gases that are not flammable, since several of the grading criteria are dependent on LEL, which is only relevant for flammable gases.

The Industry Trades commented that the proposed definition of "gas-associated substructure" was too vague and suggested PHMSA clarify the types of substructures that are intended to be included. They proposed the reference to "an operator's pipeline" to read an operator's "pipeline delivery infrastructure" and cover substructures that are not designed to transport gas, in addition to the proposed language covering substructures designed to contain gas.

3. GPAC Deliberation Summary

The GPAC was briefed on the NPRM with respect to the proposed leak grading, repair, and response requirements at § 192.760 on November 29, 2023. PHMSA's briefing included a presentation of the proposed regulatory language, including a discussion of its costs and benefits, and an overview of comments from stakeholders on the proposal. Following the briefing by PHMSA staff, the GPAC provided an opportunity for statements from stakeholders in attendance. A private citizen, individuals representing gas distribution, gas transmission, gas gathering operators, trade associations, and State pipeline safety agencies provided statements for the record. Most statements addressed the leak repair and reevaluation timelines (see section III.I), the term "leak or hazardous leak" (see section III.R), and the PRIA (see the final RIA, which is available in the docket for this rulemaking). With respect to leak grade definitions in particular, public commenters representing gas transmission and gathering operators and trade associations argued against the proposal to require a minimum grade 2 classification for all leaks on gas transmission and Type A and Type C regulated gathering lines. These commenters contended that small leaks from non-pipe components, such as valves, can be low-emitting and non-hazardous. They further noted that repairing such leaks can be costly and environmentally damaging if the operator is not given additional time to bundle maintenance activities during planned shutdowns through a longer repair timeline or notification process. Two industry representatives commented that the final rule should adopt alternatives to the proposed leakage rate standard for grade 2 leaks since smaller operators may not have the means to measure leak rate directly. A representative of a distribution company commented that establishing a national standard for leak grading was not practicable for different operating environments, and deviations from State standards would require changes to plans, procedures, training, and IT systems that would take more than 6 months to implement. They further opposed subjective criteria such as the proposed "seen, heard, or felt" standard or criteria tied to the possibility of gas migrating into buildings and suggested instead either deferring to State standards or adopting New York State standards, which are based on distance from buildings. An individual representing NAPSR observed that 20 States have stricter leak grading criteria than part 192, and States that do not have promulgated criteria typically still expect operators to adhere to GPTC guidance. Finally, an operator suggested harmonizing the definition of the term "confined space" with definitions used by OSHA or using a different term.

The GPAC deliberated on the proposed leak grading and repair requirements at § 192.760 beginning on November 30, 2023. Discussion with respect to the criteria for defining leak grades concluded with consensus votes for recommendations for criteria for defining grade 1 and grade 2 leaks. Discussion and votes on this topic focused on two primary areas: recommendations to tailor and clarify the criteria defining the degree of environmental harm caused by grade 1 and grade 2 leaks to consider system types and different measurement techniques, and changes to allow grade 3 classification for leaks on transmission and gathering lines that operate at lower stress levels and leaks from non-pipe components on gas transmission and gathering lines.

Discussion of proposed § 192.760 began with a discussion of general principles. Members raised concerns that adopting Federal leak grading and repair requirements would impact States with existing leak management requirements or pipe replacement programs as well as operators and ratepayers in such States. With respect to grading, a member representing a State requested PHMSA consider alternatives to, or an exception from, the minimum Federal standard, such as requiring operators to manage leaks under DIMP or approving State programs that follow the GPTC Guide. A member representing the public countered that the PIPES Act of 2020 directed PHMSA to establish a uniform national standard for repair requirements, but that States could exceed such standards. While members agreed in principle on the need to recognize the role of State programs and to balance environmental protection with impacts to customers and markets, the GPAC ultimately did not vote on a general set of principles. With respect to the application of these principles to leak grade definitions in particular, members representing operators agreed on the need to recognize existing State grading requirements during the transition to Federal leak grading requirements.

Substantive discussion of the grade 1 criteria began with deliberation concerning the proposed requirement to classify a leak that can be "seen, heard, or felt" as a grade 1 leak. Members representing industry commented that the sensory standard was subjective and redundant with the grade 1 criterion for leaks that are found to be hazardous in the judgment of operating personnel and should therefore be removed. A member representing a State observed that in the GPTC Guide, the sensory standard is limited to leaks "in a location that may endanger the general public or property," and limiting the criterion to those locations could alleviate other members' concerns. Several members discussed a desire to better define criteria for identifying leaks that present a "grave hazard to the environment" as opposed to a "significant hazard to the environment." Members discussed possible options of the "seen, heard, or felt" standard; the existing definition of the term "hazardous leak" in subpart P; and a numerical threshold for the purpose of defining grave environmental harm. Members also discussed whether defining grave environmental harm beyond the other grade 1 criteria was necessary. Ultimately members agreed on the need to identify criteria for leaks whose release rate merit prompt repair. A member proposed, and the GPAC ultimately agreed upon, a criterion of 100 kg/hr, consistent with the definition of a "super emitter" event in the EPA's then-proposed Super-Emitter Response Program programs.[334] A leak of this release volume is also capable of detection by more advanced methane detection satellites. GPAC members representing distribution operators and a State program raised concerns about requiring distribution operators to confirm that quantified emissions did not exceed 100 kg/hr in order to rule out a grade 1 leak, but a member noted that a leak exceeding 10 kg/hr has never been observed on a distribution system in multiple studies, and thus an operator could rule out a 100 kg/hr criterion if reaching that emissions rate is impossible given the operating characteristics of the distribution pipeline in question.

Deliberation and subsequent recommendations regarding the definition of grade 2 leaks similarly focused on more clearly defining what constitutes "significant harm" to the

[334] Now codified at 40 CFR 60.5371, 60.5371a, 60.5371b, and 60.5371c.

environment sufficient to justify an intermediate repair priority. Deliberation focused on establishing standards for distribution and transmission and gathering systems, considering differences in operating characteristics. Beginning with a discussion of the grade 2 criteria for leaks on distribution lines, a member representing a gas distribution operator introduced a recommendation to allow alternative methods to the 10 SCFH standard proposed in the NPRM, including an estimated leak migration extent of 2,000 square feet or greater. Members representing the public supported the 10 SCFH criteria as a widely accepted standard for "super-emitting" distribution leaks, as adopted by operators in New York and California, and were concerned about the effect site-specific variables might have on leak migration extent criteria as compared with volume-based measures. They suggested addressing the practicability concern by limiting the leak-rate standard to larger distribution operators and allowing alternative methods for smaller operators. A member representing a State suggested adopting 20 SCFH, consistent with design requirements for EFVs, and raised concerns that the grade 2 criteria were lower than the detection limit of 0.5 kg per hour.

Finally, members discussed the allowance for an alternative method for identifying environmentally significant leaks on distribution lines. Members representing the public and a State representative were concerned about an open-ended allowance for an alternative. On the other hand, other State representatives and distribution operators were concerned about excluding technologies and methods other than direct measurements or leak migration extent. After discussion, the committee balanced the desire to allow alternative compliance methods with the need to ensure that such methods achieve program objectives by recommending that alternative methods be subject to review and approval by PHMSA, in accordance with § 192.18, and be judged based on equivalency with the leak-rate standard.

Regarding grade 2 criteria applicable to gas transmission and gathering lines, the GPAC agreed on prioritizing the repair of leaks on portions of pipelines that could rupture. Members representing transmission line operators emphasized the need for flexibility for small leaks on non-pipe components and on low-stress (i.e., operating at less than 30 percent SMYS) pipelines that are less likely to rupture. To coordinate the repair of such leaks with larger maintenance projects, they requested the GPAC consider recommending a grade 3 classification for leaks on gas transmission lines, other than leaks from the body of a pipeline operating at above 30 percent SMYS, that do not meet the criteria for grade 1 or grade 2 leaks. A member representing a State agreed that tying the prioritization criteria to the operating stress to which the pipe was exposed rather than the pipe's regulatory classification better reflected the safety objectives of the proposed grade 2 criterion, since some transmission lines can operate at low pressure. Since allowing grade 3 classification would make the grade 2 criteria for larger-volume leaks salient for gas transmission and gathering lines, members discussed appropriate criteria for defining transmission line leaks that warrant repair on a grade 2 schedule due to their release rate. Beginning the discussion of appropriate thresholds for larger-emitting transmission leaks warranting repair on a grade 2 schedule, a member representing the public explained that while 10 SCFH makes sense for distribution system where leaks are individually relatively small, researchers have found transmission and gathering leaks are larger, and that a 5 to 10 kg/hr leak rate appropriately targets relatively large leaks from such systems. The GPAC ultimately recommended PHMSA consider a range of 5 to 10 kg leak rate for the grade 2 criteria for gas transmission and gathering lines, but members representing operators cautioned that it would not be beneficial or cost-effective to repair leaks on the smaller end of that range within the proposed 6-month repair timeline, and that 12 to 36 months was necessary for operators to repair leaks that require shutdown or blowdown to be cost-effective.

4. GPAC Recommendation

The Committee unanimously recommended that PHMSA revise the grade 1 leak "seen, heard, or felt" criterion at § 192.760(b)(1)(vii) to be consistent with the GPTC Guide language. The Committee also unanimously recommended that PHMSA add a flow-rate criterion of 100 kg/hr to provide a more objective and quantifiable measure of leaks presenting a "grave" environmental hazard. The Committee then advised PHMSA to clarify the meaning of "grave" environmental hazard or provide more clarity on what conditions pose a grave environmental hazard, if any, beyond leaks with a flow rate of 100 kg/hr or more.

With respect to distribution pipelines, the Committee also unanimously recommended that PHMSA finalize the grade 2 flow rate criterion at 10 SCFH and add a leak extent criterion. The Committee recommended that such a leak extent criterion reflect a magnitude that would pose significant harm to the environment, which the Committee suggested would be indicated by choosing any one of the following methods: 1) an estimated leakage rate of 10 SCFH or more as indicated by suitable technology; 2) for below-grade and subsurface leaks, an estimated leak extent of 2,000 sq-ft. or greater; or 3) an alternative method demonstrated to meet the capability of identifying a minimum leak rate of 10 SCFH consistent with method A, with a notification to

PHMSA in accordance with § 192.18. The Committee recommended that PHMSA should consider the availability of the leak extent approach for appropriate conditions. For transmission and gathering pipelines, the Committee unanimously recommended that PHMSA replace the proposed grade 2 flow rate criterion with "an appropriate volume threshold for a transmission or regulated gathering line, such as 5 to 10 kg/hr" and recommended that PHMSA add as a new grade 2 criterion any reading of gas that does not qualify as a grade 1 leak occurring in the pipe body of a transmission pipeline or a regulated gas gathering line operating at high stress, which the Committee defined as greater than 30 percent SMYS.

Deliberation on actionable repair criteria for grade 3 leaks is addressed in section III.I below.

5. PHMSA Response

General

PHMSA is adopting leak grading criteria in this final rule that are heavily informed by, but intentionally differ from, the GPTC Guide. As first described in the NPRM, while the leak grading criteria finalized in this rulemaking are based largely on the grading framework described in the GPTC Guide to reduce the burden on operators by leveraging familiarity with the GPTC Guide across the industry. However, the GPTC Guide is focused solely on public safety, while PHMSA has been directed by Congress to consider both the public safety and environmental hazards of leaks. Therefore, PHMSA has supplemented the GPTC Guide framework with new grading criteria and repair requirements that better address environmental harms. These additions to the safety-based guidelines are necessary to achieve the objectives of the section 113 mandate of the PIPES Act of 2020 with regard to establishing appropriate timelines for the repair of leaks that pose a potential hazard to the environment. In addition, PHMSA has introduced modifications to the longstanding criteria of the GPTC Guide for improved clarity and enforceability, and to reflect other improvements suggested by commenters and the Committee throughout the development of this rulemaking. Additionally, PHMSA did not propose to incorporate by reference the GPTC Guide and is therefore unable to do so in this final rule.

In the intervening years since PHMSA issued general repair requirements in § 192.703 and "effective leak management program" requirements for distribution lines in § 192.1007(d), States, the GPTC, and operators have intervened to define expectations around these requirements, including establishing leak grading standards. PHMSA appreciates that while most entities have adopted leak classification schemes influenced by the GPTC guide, some classification schemes, such as the distance-based criteria in the State of New York, differ significantly from the GPTC guide and those in this final rule. However, Congress directed PHMSA to establish a minimum Federal standard for categorizing leaks for repair; GPTC guide-based categorization schemes are common nationwide, and therefore building on that framework has been demonstrated to be practicable and is easier to implement for most operators nationwide. In addition to imposing additional implementation burden on most operators, replacing the proposed grading criteria with distance-based measures likely falls outside of the scope of the proposal. States and operators are free to have standards exceeding the minimum Federal requirements in part 192. To the extent that alternative practices are incompatible with

§ 192.760, PHMSA did not propose mechanisms for an operator or State to use entirely different leak grading schemes, however an operator could request a special permit or State waiver if they can demonstrate that an alternative grading scheme would provide an equivalent level of public safety or environmental protection. Finally, with respect to comments concerning criteria based on gas-in-air measurements rather than percent LEL, percent gas in air is convertible to percent LEL, and therefore these tools and methods are not inherently in conflict.

PHMSA appreciates the concerns raised by commenters that the introductory language for the grade 1 and grade 2 leak criteria sections in the NPRM was unclear, especially with regards to the terms "significant" and "grave" harm to the environment. PHMSA did not intend for this introductory language to introduce new criteria beyond those items listed in proposed §§ 192.760(b)(1) and (c)(1). Therefore, PHMSA has removed this introductory language from this final rule and now refers simply to the listed criteria for determining grade 1 or grade 2 leaks. Operators will not be required to independently develop distinctions between leaks that represent "significant" or "grave" hazards to the environment. PHMSA is also adopting the GPAC recommendations for leak-rate criteria for grade 1 and grade 2 leaks in this final rule, which will provide operators with an objective measure of leaks that must be repaired on a grade 1 or a grade 2 schedule due to the magnitude of emissions.

Commenters raised concern about the terminology "could migrate" with respect to certain criteria for grade 1 and grade 2 leaks. In the grade 1 criteria, the proposed language referred to accumulations where gas could migrate to the outside wall of a building. This language was inadvertently omitted from the grade 2 criteria for gas readings inside of substructures, implying that any gas migration from a substructure constituted a grade 2 leak regardless of concentration; this has been corrected in this final rule. When an operator is evaluating, either in their procedures or in the field, whether gas could migrate to the outside wall of a building, they should consider potential factors that can influence gas migration. Such factors include the proximity of nearby buildings, soil and pavement conditions, and the presence of pathways for gas migration such as electric, communication, or sewer conduits and other buried utilities. While the NPRM did not propose specific requirements for leak investigation, the GPTC guide provides guidance and model procedures for evaluating the extent of gas migration of a probable leak.

Regarding the definition of a gas-associated substructure, the definition in this final rule includes examples of substructures from comments from the Industry Trades and further clarifies that a substructure is not intended to contain gas under pressure. PHMSA also replaces the term "pipeline" with "pipeline facility," which is defined in § 192.3 and better reflects a substructure that is used in the transportation of gas but does not itself contain pressure. While commenters recommended the term "pipeline delivery infrastructure," "pipeline facility" is a defined term in part 192 and addresses the commenter's intent. Since all portions of a pipeline facility, by definition, are designed to transport gas, PHMSA does not adopt the Industry Trades' recommendation to clarify that a gas-associated substructure is not designed to transport gas. This final rule instead clarifies that a gas-associated substructure is not designed to contain pressure (i.e., gas does not flow through it during normal operation).

Regarding gases under part 192 that are non-flammable, which includes toxic and corrosive gases under § 192.3, criteria related to percent LEL are not applicable. However, other criteria, such as those related to the judgement of operator personnel; leaks that can be seen, heard, or felt in areas that can endanger public safety; volume; and any reading of gas in and around buildings do apply. Additionally, operators of gas pipelines, including non-flammable toxic and corrosive gases, are required under 49 U.S.C. 60108 to have procedures that address "eliminating hazardous leaks."

Grade 1 Criteria

Consistent with the NPRM, any leak that meets any of the criteria listed in § 192.760(b)(1) is a grade 1 leak, the highest priority in this final rule. Many commenters suggested that PHMSA should focus its grade 1 leak criteria solely on public safety risks, like the GPTC Guide. However, the section 113 mandate of the PIPES Act of 2020 not only directs PHMSA to promulgate LDAR program requirements "to meet the need for gas pipeline safety," but also to "protect the environment." In fact, this rulemaking must include requirements to "identify, locate, and categorize all leaks that are hazardous to […] the environment." PHMSA's statutory authority under this provision is discussed in further detail in section III.T. Since the magnitude of environmental harm from methane or other greenhouse gases released from gas pipeline leaks is proportional to the amount of gas released, PHMSA initially proposed a modification to the GPTC "seen, heard, or felt" criterion to leaks regardless of location. This was intended as a relatively simple means for personnel to immediately identify leaks that are so large that they are identifiable by visible, audible, or even tactile means. An objective measurement of leak magnitude was not proposed in the NPRM, out of a concern that some measurement or calculation techniques might be time consuming, which could delay an operator's obligation to take immediate and continuous action to address a grade 1 leak. However, PHMSA appreciates the public comments and GPAC discussion concerned with the potential subjective nature of such a standard and concerns that many leaks on a high-pressure transmission or gathering line may be audible. PHMSA agrees that objective criteria are more practicable for operators and will reduce the likelihood that operators must treat less hazardous leaks, such as small leaks occurring on valve operators and packing, as grade 1 simply because they make a sound.

This final rule therefore adopts GPAC recommendations to more objectively define leaks that pose a grave hazard to the environment. In that vein, PHMSA now includes the recommended 100 kg/hr release rate criterion as one of the different ways an operator can define a grade 1 leak. PHMSA agrees that release rate is less subjective and is a better measure of the leaks that present the greatest hazard to the environment. This criterion can be established by calculation in addition to direct measurement to provide flexibility for operators to immediately and continuously address these hazardous conditions. PHMSA has limited the scope of this criterion to gas transmission and regulated gas gathering lines. A leak on a gas distribution line exceeding 100 kg/hr has not been observed based on information available to PHMSA. Should a leak of that size occur on a distribution line, it would likely require prompt repair regardless due to meeting one of the other grade 1 criteria or rending the facility inoperable or unsafe per § 192.703(b). Distribution line operators would therefore not be required to confirm that a leak was below 100 kg/hr, which simplifies leak investigation for distribution operators. Since a distribution operator would likely promptly repair a leak exceeding 100 kg/hr in the unlikely event that such an event occurred, this change eliminates the costs associated with confirming that a leak does not exceed 100 kg/hr with no expected impact on repair decisions.

Compared with distribution systems, leaks on gas transmission and especially gas gathering lines are more likely to exceed 100 kg/hr, which makes identifying such releases for immediate repair more beneficial. Additionally, leaks in general are less frequent on such facilities compared with distribution lines, reducing total costs associated with confirming that leaks do not exceed 100 kg/hr. Finally, PHMSA expects that most transmission and gathering line operators will comply with the ALDP standards using screening surveys that can measure or identify leaks of 100 kg/hr. The 100 kg/hr criterion has been adopted by the EPA for the super-emitter program and for reporting under the "other large release event" source category in subpart W of the GHGRP, which are applicable to transmission and gathering facilities and demonstrates the practicability of identifying such leaks and addresses requests from public comments and the GPAC to better harmonize requirements with EPA standards. Specifically, the 100 kg/hr flow-rate criterion is intended to harmonize with the definition of a "super-emitter event" adopted in the EPA final rule titled "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" published on March 8, 2024.[335] Specifically, that rule defines a "super-emitter event" as "any emission event that is located at or near an oil and natural gas facility

[335] 89 FR 16820 at p. 16876. (March 8, 2024).

(*e.g.,* individual well site, centralized production facility, natural gas processing plant, or compressor station) and that is detected using remote detection methods and has a quantified emission rate of 100 kg/hr of methane or greater."[336] On May 14, 2024, the EPA published a final rule that requires reporting of "other large release events," defined in 40 CFR 98.233(y)(1) to include any release of methane at a rate of 100 kg/hr if the source is not subject to reporting under certain source categories (40 CFR 98.233 (a) through (s), (w), (x), (dd), or (ee)) and for sources subject to reporting under certain source categories (40 CFR 98.233(a) through (h), (j) through (s), (w), (x), (dd), or (ee)), a release that emits methane at any point in time at a rate of 100 kg/hr in excess of the emissions calculated using the applicable source category, as part of the GHGRP.[337] PHMSA's adoption of a similar flow-rate criterion will therefore help operators streamline their procedures to comply with PHMSA repair requirements and EPA reporting requirements, if applicable, whenever a leak of this magnitude is detected.

PHMSA is also finalizing a "seen, heard, or felt" criterion, but it is re-aligning that criterion with the GPTC Guide by limiting its application to those leaks in a location that may endanger the general public or property. Since this rulemaking has finalized an objective flow-rate criterion for identifying leaks that are most hazardous to the environment, the "seen, heard, or felt" standard (e.g., leaks detectible by human senses) can now be focused on leaks that present public safety hazards, supplementing the other gas concentration-based criteria. Operators should continue to implement this criterion as they have under the GPTC Guide.

[336] Introductory text to 40 CFR 60.5371, 40 CFR 60.5371a, 40 CFR 60.5371b, and 40 CFR 60.5371c.
[337] 89 FR 42062, "Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems" (May 14, 2024).

Visible indications of a leak may include, for example, ground disturbances, a jet or vapor cloud of condensation, or blowing debris. Audible indications of a leak can include a hissing sound or, for larger leaks and ruptures, sounds resembling a jet engine or train. Tactile indications of a leak can include force from a jet of gas or vibrations in the pipe or soil. PHMSA appreciates the opportunity to clarify that operators should never intentionally evaluate leaks by touching them – rather, if operator personnel feel a leak incidentally, then it may qualify as a grade 1 leak under this criterion if it is in a location that may endanger the general public or property. Each of these physical markers of a pipeline leak are typically more apparent on higher-pressure, larger-volume leaks. PHMSA does not consider impacts to vegetation to be a definitive indication of a grade 1 leak for these purposes since vegetation impacts can also occur over time as a result of smaller leaks. However, severe or widespread impacts to vegetation may be indicative of a larger leak and should be considered when an operator is grading the leak or scheduling repair.

Similarly, minimal bubbling observed during a soap test or visible at the leak location on a submerged pipeline does not necessarily indicate a grade 1 leak. However, a leak on an offshore pipeline that is visible from the surface (i.e., bubbles or condensate sheen) in a location that may endanger the public or property would be classified as a grade 1 leak under this criterion, though such locations are likely rare offshore. PHMSA acknowledges that a prompt repair in the offshore environment is not synonymous with instant. As noted in public comments a significant portion of subsea methane leaks are absorbed by seawater; therefore, methane bubbles visible from the surface could represent a significant leak. Additionally, natural gas condensate often contains materials toxic to humans and aquatic ecosystems; therefore, visible quantities of natural gas condensate in water likely represents a hazard to human health and the environment. Operators should continue to implement this criterion as they have under the GPTC Guide.

Additionally, for the criteria for leaks that justify immediate repair in the judgement of operating personnel (proposed at § 192.760(b)(1)(i)), this final rule removes the stipulation that the determination by operator personnel must be made by personnel "in the field," which helps ensure that more operator personnel are able to determine that an individual leak justifies immediate repair. Because the "judgement of operator personnel" may only be used to elevate a leak to a higher-priority grade, this provides more flexibility for operator procedures with no negative impact on safety or environmental protection. This criterion can be used to identify any leak as a grade 1 leak without the need for further investigation. In other words, an operator may use this criterion to immediately classify a leak as grade 1 without further investigation effort if hazards are immediately obvious to operator personnel, if operators promptly repair all leaks when found, or for any other reason. This clarification should address concerns that grading activities could delay the repair of leaks that are obviously hazardous or would impose administrative burdens on operators who repair all leaks immediately by default.

PHMSA has adopted recommendations from comments to clarify that a leak resulting in a positive gas reading at the outside wall of a building is grade 1 if such readings are found below grade. Aboveground readings at the outside wall of a building are not necessarily grade 1 leaks. This change clarifies that some potentially lower-risk aboveground leaks, like small leaks from meter assemblies, do not require immediate repair if they do not meet other grade 1 criteria. However, there are less-likely scenarios where gas can migrate into a building from aboveground, or an aboveground gas reading could be caused by gas that has already accumulated inside of the building. Therefore, when investigating a leak, if an aboveground reading is found at the outside wall of a building, an operator should confirm there is no below-ground reading at the perimeter of the building and that gas has not entered the building under paragraph (b)(1)(iii) before ruling out a grade 1 leak.

Section 4.2.2.2 and section 4.1.3.2 of the RIA describe the cost analysis for the leak grading criteria as they apply to gas distribution lines and gas transmission or gathering lines, respectively. As described in the RIA, the grade 1 leak criteria generally reflect existing practices represented in the GPTC guide and PHMSA guidance on complying with the previous repair requirements in § 192.703(c). Compared with the GPTC guide, the final rule adopts two new criteria for leaks on gas transmission or regulated as gathering lines with a flow rate of 100 kg/hr, or any leak that is reportable as an incident. However, such very large leaks from gas transmission and gas gathering lines or incidents that resulted in serious or fatal injuries, significant property damage, or large gas releases per § 191.3 would have been considered "hazardous leaks" and promptly repaired under existing regulations, especially for gas transmission and Type A gas gathering lines that operate at high pressure. Due to the conformity with baseline practice recommended by the GPTC Guide and required by section 114 of the PIPES Act of 2020, PHMSA does not expect marginal costs or benefits associated with the grade 1 criteria adopted in the final rule. Since leaks with a flow rate exceeding 100 kg/hr represent the largest releases, to the extent that such leaks were not being repaired under the baseline requirements, the final rule would result in significant environmental and safety benefits.

Grade 2 Criteria

Any leak, other than a grade 1 leak, that meets any of the criteria in paragraph (c)(1) is a grade 2 leak that must be scheduled for repair. This final rule makes several revisions to the proposed grade 2 leak criteria to address concerns raised by commenters and recommendations from the GPAC. Specifically, PHMSA is adopting two separate flow rate criteria, one for classifying grade 2 leaks on gas distribution lines and another for classifying grade 2 leaks on gas transmission and regulated gas gathering lines.

Leak Rate Criteria—Gas Distribution

For gas distribution pipelines, this final rule requires operators to classify leaks as grade 2 via any of three methods: the 10 SCFH standard as proposed in the NPRM; a measured leak extent of 2,000 square feet or greater; or an alternative method demonstrated to be equivalent to the 10 SCFH standard with notification to PHMSA and State regulators in accordance with § 192.18. This additional flexibility will allow gas distribution operators to choose between using traditional concentration-based leak survey equipment or flow rate-based equipment, helping address the concern from commenters that the equipment and expertise to quantify gas distribution pipeline emissions are not yet widespread. This framework will also facilitate the future deployment of innovative technologies and procedures that may emerge in the future, with oversight from regulators, potentially including alternative methods described in public comments.

This final rule retains the 10 SCFH grade 2 criterion for gas distribution lines. As noted in the preamble to the NPRM, this criterion will help ensure that operators prioritize the repair of larger leaks on gas distribution lines even if other grade 1 or grade 2 criteria are not met, thus minimizing the environmental and safety risk presented by larger leaks. PHMSA's selection of a 10 SCFH emissions rate is consistent with data, corroborated by public comments, indicating that a significant share of emissions from natural gas pipeline systems can be caused by a relatively small proportion of leaks. A 2016 analysis by Brandt, et.al., of 15,000 emissions measurements from prior studies found that 5 percent of releases contributed to over half of total emissions volumes.[338] An emissions rate of 10 cubic feet correlates to emissions of approximately 87,600 ft^3 of methane (roughly 1,600 kg of methane) if left unrepaired for a year.[339] Voluntary industry efforts have also used implemented similar criteria in order to address the outsized impact of these larger leaks; for example, PG&E elected to use a 10 SCFH criterion in its Super Emitter Program based on data showing that methane leaks larger than 10 SCFH represented only 2 percent of all leaks by number but over half of all emission volumes on PG&E's gas distribution system.[340] As described in section 4.2.2.2 of the RIA, PHMSA

[338] Brandt AR, Heath GA, Cooley D. Methane Leaks from Natural Gas Systems Follow Extreme Distributions. Environ Sci Technol. 2016 Nov 15;50(22):12512-12520. Doi: 10.1021/acs.est.6b04303. Epub 2016 Oct 26. PMID: 27740745.

[339] The value here was calculated assuming a density of methane of 0.01926 kg/ft^3.

[340] Rongere, Francois. "Lessons Learned from the First Year of the Super Emitter Program." PG&E Nov. 5, 2019. https://www.epa.gov/sites/default/files/2019-12/documents/lessonslearnedfirstyearsuperemitterprogram_francoisrongere.pdf; Lamb, Brian K., et al. "Direct Measurements Show DECREASING Methane Emissions from Natural Gas Local Distribution Systems in the United States." *Environmental Science & Technology*, vol. 49, no. 8, 2015, pp. 5161–5169., doi:10.1021/es505116p.

performed an analysis of gas distribution leaks based on data from States that report leaks discovered and repaired by grade and emissions data from Lamb et al. 2015. PHMSA estimated that approximately 24% of leaks would be classified as Grade 2 leaks based on the grading criteria in the GPTC guide. In order to estimate the impact of requiring repair of leaks with a flow rate of 10 SCFH or more (or, as described below, an equivalent leak extent criteria) on a grade 2 timeline, PHMSA applied the distribution of emissions by size from Lamb et al. 2015 to the estimated number of grade 3 leaks (approximately 34 percent of all leaks). PHMSA estimates that such leaks represent approximately 2 percent of grade 3 leaks but result in half of emissions from grade 3 leaks, or 17.3 percent of total gas distribution emissions. Changing the designation of these leaks increases the safety, health, and environmental benefits associated with reducing the duration of the leak, with corresponding increases in cost from accelerating repairs from a grade 3 timeline. In section 2.2.6, PHMSA evaluated an alternative that excluded emissions-based grading criteria, including the 10 SCFH (or equivalent) criteria for grade 2 leaks on gas distribution lines. Under this alternative, PHMSA assumes operators would only repair grade 3 leaks voluntarily or to comply with state regulations, with an average repair timeline of 5 years unless a state requires a shorter timeline. However, PHMSA did not adopt this alternative as it foregoes quantified and unquantified benefits that exceed foregone costs.

PHMSA disagrees with comments suggesting that the 10 CFH leakage rate criteria applicable to distribution lines should be revised to be consistent with the design requirements for service line EFVs in § 192.381(a)(3). This EFV flow rate standard was developed in 1996 for an entirely different purpose, defining the maximum allowable gas flow through closed-bypass

EFVs, and was never intended to define the significance of a leak. Furthermore, a failure that causes an EFV to close has a high likelihood of being a grade 1 leak.

While release rate is a more direct measure of larger leaks, PHMSA is also finalizing an alternative 2,000 square foot leak extent criterion based on the Commonwealth of Massachusetts regulations.[341] A 2019 report by the "Home Energy and Efficient Team" (HEET) supporting the development of the Massachusetts leak extent method in appendix 2 of that report cites a previous 2017 study[342] of leaks that found that "emissions of a leak are strongly correlated (n=67, R2=0.86) with the leak extent, or size of the gas-saturated surface area over the leak."[343] That research further found that leaks with a leak extent greater than 2,000 sq. ft had an average release rate of 280 SCF per day, or 11.7 SCFH, compared with an average release rate of 26 SCF per day observed on leaks with a measured leak extent less than 2,000 sq. ft.[344] Therefore, the leak extent criteria PHMSA is finalizing in this rulemaking is likely to capture most leaks with a release rate greater than 10 SCFH on average. Subsequent evaluations of the Massachusetts "significant environmental impact" criteria have measured its performance among operators that use the criteria. In the year 2 report for 2020 – 2021, participating operators identified 2.2 to 5.6 percent of their leaks as leaks with significant environmental impact based on the leak extent

[341] 88 FR 31890 at p. 31941 (May 18, 2023), and 220 CMR 114.07(1)(a)(2)

[342] Magavi, Zeyneb Pervane. "Identifying and Rank-Ordering Large Volume Leaks in the Underground Natural gas Distribution System of Massachusetts," (May 2018) http://nrs.harvard.edu/urn-3:HUL.InstRepos:37945149;

[343] HEET. "Natural Gas Leaks of Significant Environmental Impact: Report of the 2018 SEI Field Trial." (March 2019). https://www.heet.org/gas-leaks/shared-action-plan-trial-year. Pg. 7.

[344] Magavi, Zeyneb Pervane. "Identifying and Rank-Ordering Large Volume Leaks in the Underground Natural gas Distribution System of Massachusetts," (May 2018) http://nrs.harvard.edu/urn-3:HUL.InstRepos:37945149. pg. 50.

criteria.[345] The report recommended operators adjust the significant environmental impact criteria to cover each operator's largest 7 percent of leaks,[346] which, as research cited in the report noted, is expected to account for half of leak-related emissions in Massachusetts.[347] The report acknowledged the difference between leaks identified under the leak extent criteria and the 7 percent of leaks target may be partially explained by improvements to operator leak management programs and failure to identify leaks, which would be addressed by other parts of this final rule related to leak surveys and ALDP requirements. While PHMSA encourages operators to prioritize the repair of larger leaks, this final rule does not require operators to adjust their leak extent criteria to target a certain percentage of leaks. As noted in the preamble to the NPRM, PHMSA is refraining from adopting relative leak size as a criterion because of the potential to remove incentive to prevent leaks, since operators would be required to prioritize repair of the same fraction of leaks regardless of the underlying integrity performance of the pipeline facility. The Code of Massachusetts Regulations does not prescribe a method for measuring leak extent, but the HEET report includes an appendix describing a protocol "created by all Massachusetts gas companies" to implement the criteria.[348] In this method, the leak extent is determined by the area of a rectangle containing any belowground reading of gas obtained in

[345] HEET. "Natural Gas Leaks of Significant Environmental Impact (SEI): Shared Action Plan Year 2" (February 9, 2022)", https://www.heet.org/gas-leaks/shared-action-plan-year-2. pg. 13.
[346] HEET. "Natural Gas Leaks of Significant Environmental Impact (SEI): Shared Action Plan Year 2" (February 9, 2022)", https://www.heet.org/gas-leaks/shared-action-plan-year-2. pg. 13
[347] HEET. "Natural Gas Leaks of Significant Environmental Impact (SEI): Shared Action Plan Year 2" (February 9, 2022)", https://www.heet.org/gas-leaks/shared-action-plan-year-2. pg. 6.
[348] HEET. "Natural Gas Leaks of Significant Environmental Impact: Report of the 2018 SEI Field Trial." (March 2019). https://www.heet.org/gas-leaks/shared-action-plan-trial-year. Appendix 2 at pg. 23.

accordance with the operator's procedures. The length is the distance, parallel to the pipeline, between belowground, readings of zero gas. Likewise, the width is the distance perpendicular to the pipeline between the furthermost zero readings measured from belowground. PHMSA is expressly codifying the HEET method of measuring leak extent of below-grade and subsurface gas distribution leaks to help ensure that operators can readily apply this new criterion. PHMSA acknowledges that a leak extent criterion may perform differently based on the operating characteristics of a gas distribution line, soil conditions, and other environmental parameters. However, based on public comments and GPAC discussion regarding the availability of tools available for measuring emissions from relatively small leaks (compared with gas transmission leaks) on buried distribution pipelines in the near term, PHMSA determined that providing this flexibility was necessary to provide a practicable alternative means for identifying larger-volume leaks. This method provides a means for operators to identify larger-volume leaks using traditional leak survey equipment and methods, which is valuable until screening survey technologies and other quantification methods become more widespread and affordable. As it does with all of the PSR, PHMSA will evaluate the performance of the leak extent criteria in this final rule, considering its reliability of capturing larger leaks and the state of emissions quantification technologies.

This final rule also allows an operator to request to use an alternative method for identifying gas distribution leaks based on their size via a notification to, and no objection from, PHMSA and any applicable State authority in accordance with the notification process in § 192.18. An operator must demonstrate that an alternative method approved under this process is capable of reliably identifying leaks exceeding the 10 CFH criteria for gas distribution leaks. PHMSA recognizes the value for a pathway to approving, with oversight from Federal and State regulators, alternative methods and technologies for identifying potentially harmful leaks. For example, commenters and GPAC members expressed interest in alternative means of identifying leaks meeting the size criteria. Commenters suggested alternatives based on the sum of barhole readings in the leak area but did not provide recommended criteria or supporting information. Such a method could potentially be approved if the operator demonstrates the effectiveness of the proposed alternative method at identifying leaks exceeding 10 SCFH via a notification process.

Leak Rate Criteria—Transmission and Gathering

For gas transmission and regulated gas gathering pipelines, this final rule adopts a release-rate criterion of 10 kg/hr for identifying grade 2 leaks, as supported by commenters and the GPAC. GPAC members noted that leaks from transmission and gathering lines operating at higher pressures are larger on average than leaks on distribution lines, and different environmentally targeted criteria may be appropriate for distribution lines or for transmission and gathering lines. Several commenters had expressed concerns that the proposed 10 CFH criterion was inappropriately small for designating grade 2 leaks on transmission lines. Consequently, for gas transmission pipelines, the Committee recommended that PHMSA consider a release rate range between 5 and 10 kg per hour for grade 2 transmission pipeline leaks. This final rule includes a release-rate criterion for gas transmission lines at 10 kg/hr for grade 2 leaks. This standard is consistent with the leak-rate performance standard adopted for screening surveys on gas transmission and regulated gas gathering lines in this final rule (see section III.C for more discussion of the performance standards for screening surveys). Leaks identified through other means that fall below this level could be classified as a grade 3 leak as described below. Regarding comments suggesting a 100 kg/hr criterion, PHMSA has adopted this value as a criteria for immediate repair of grade 1 leaks as described above. PHMSA's updated RIA for this rulemaking as well as emissions modeling prepared by public commenters representing both public advocacy organizations and industry trade associations have shown significant emissions reduction benefits from establishing a repair timeline for transmission and especially gas gathering line leaks exceeding 10 kg/hr; on the other hand, the commenter did not provide evidence supporting 100 kg/hr. As described in section III.I, this final rule doubles the repair timeline for grade 2 leaks and provides an allowance for pipe replacement programs, which should mitigate cost and practicability concerns.

As described in section 4.1.3.2 of the RIA, PHMSA performed an analysis of gas transmission and gas gathering leak grades. Compared with gas distribution lines, state-level data on the distribution gas transmission and gas gathering leaks by grade was not available, though commentors hypothesized on the distribution of such leaks by grade and public comments and statements in the administrative record reflected widespread agreement that a small number of relatively large leaks represented the majority of emissions for gas transmission and especially regulated gas gathering lines. Based on this information, an evaluation of the distribution of emissions volumes for leaks reportable as incidents, PHMSA established a model of the distribution of gas transmission and gas gathering leaks and emissions by grade. Based on this model, 20% of both leaks and emissions are attributable to grade 2 leaks, including those identified by the 10 kg/hr. criteria. Changing the designation of these leaks increases the safety, health, and environmental benefits associated with reducing the duration of the leak, with corresponding increases in cost from accelerating repairs from a grade 3 timeline. Compared with the status quo, this results in the accelerated repair of relatively large gas transmission leaks, provided such leaks were not being repaired within 12 months under baseline compliance. On the other hand, compared with the proposed rule it significantly reduces the number of leaks on gas transmission and gas gathering lines that would have been captured by the 10 SCFH criteria proposed in the NPRM. As modeled in the RIA, grade 3 leaks, including leaks smaller than 10 kg/hr, are estimated to represent 70 percent of leaks but only 10 percent of total emissions. Allowing grade 3 designation for lower-stress gas transmission and Type A and Type C regulated gas gathering lines and adopting a 10 kg/hr flowrate criteria rather than the proposed 10 SCFH criteria therefore significantly reduces the cost of accelerating repair of a large number of leaks with a relatively minor impact on emissions compared with the proposed repair requirements for such facilities. In section 2.2.6, PHMSA evaluated an alternative that excluded emissions-based grading criteria, including the 10 kg/hr criteria for grade 2 leaks on gas transmission and regulated gas gathering lines. Under this alternative, PHMSA assumes operators would only repair grade 3 leaks voluntarily or to comply with state regulations. However, PHMSA did not adopt this alternative as it foregoes quantified and unquantified benefits that exceed foregone costs.

Minimum Grade 2 Classification on Certain Pipelines

This final rule narrows the proposal to implement a minimum grade 2 classification for leaks on transmission lines and Types A and C gathering lines, such that the minimum grade 2 classification would be limited to certain high-risk leaks that either have a higher probability of rupture or that are in densely populated areas. PHMSA is finalizing the minimum grade 2 classification for leaks from the pipe body (including pipe-to-pipe connections) of a pipeline with an operating pressure producing a hoop stress greater than or equal to 30 percent of SMYS, as well as for leaks on a gas transmission line located in an HCA or a gas transmission or regulated gas gathering line, each located in a Class 3 or Class 4 location. In this final rule, lower-risk grade leaks on gas transmission lines can now be classified as grade 3 leaks with longer repair timelines. This includes, for pipelines not located in HCAs or Class 3 or Class 4 locations, leaks on the pipe body on transmission and gathering lines that operate at a lower stress level, and, for pipeline facilities in all areas, leaks from non-pipe components such as packing leaks on valves and other component leaks. As noted above, this revision reduces the costs associated with accelerated repair of relatively small leaks that would have otherwise been classified as grade 3.

PHMSA agrees with the GPAC and commenters that leaks on pipeline facilities operating at pressures below 30 percent of SMYS, as well as leaks on non-pipe body components, are at lower risk of developing into ruptures. For the purposes of this requirement the term "pipe body" includes welds, couplings, and flanges connecting line pipe.

PHMSA similarly agrees with commenters that leaks from gas transmission and regulated gas gathering lines in HCAs and Class 3 or 4 locations represent greater risks to public safety due to the higher likelihood of proximity to people and property. Since PHMSA is simultaneously adopting a 12-month repair timeline for grade 2 leaks, this minimum grade 2 classification for leaks in HCAs and Class 3 or Class 4 locations is consistent with the GPAC's recommendation that all grade 3 leaks in such locations be repaired within 12 months, as discussed further in section III.I. Consistent with the GPAC recommendations regarding repair requirements (see section III.I), leaks in Class 3 and Class 4 locations and HCAs that meet the grade 2 criteria addressing flammability risk in § 192.760(c)(1)(i) through (c)(1)(vi) are subject to a 30-day repair requirement in (c)(4), reflecting the higher potential consequences should a fire or explosion occur in these locations.

PHMSA has retained in this final rule the minimum grade 2 classification for all leaks of LPG. While the GPTC Guide material for LPG includes grade 2 and grade 3 criteria, it also cautions that "because petroleum gas is heavier than air and will collect in low areas instead of dissipating, few leaks can safely be classified as Grade 3."[349] PHMSA finds that the higher likelihood of accumulation in low-lying areas, such as basements, sewers, and other belowground structures, together with the lower likelihood of dissipation with time, makes leaks of LPG uniquely hazardous. A leak of any amount of LPG risks a hazardous accumulation of flammable gas if it remains unaddressed, and since LPG is less likely to naturally dissipate, this risk is more likely to increase over time, even with a very small leak. A minimum grade 2

[349] GPTC Guide GM Appendix G-192-11A, Table 3c "Leak Classification and Action Criteria—Grade 3"

classification is particularly important considering PHMSA's decision to modify the grade 3 leak repair requirement such that operators are not required to repair all leaks (as discussed further in section III.I).

Leak Grading Terms and Definitions

PHMSA agrees with commenters that aligning PHMSA's definition for "confined space" with the definition used by OSHA in 29 CFR 1910.146 has the advantage of minimizing confusion in operator procedure manuals and simplifying the identification of confined spaces with respect to an operator's own facilities. In the NPRM, PHMSA proposed a definition similar to the one used in the GPTC Guide for consistency with that industry guidance, but a large number of commenters, including the Industry Trades, indicated that operators currently use OSHA's definition in their procedures. PHMSA agrees that the OSHA definition largely addresses the need to identify hazardous accumulations of gas within confined spaces while minimizing confusion and leveraging existing operator practice. However, since this criterion applies beyond spaces controlled by the operator, such as manholes and larger vaults operated by other utilities, PHMSA has removed references to employees in the final definition within this final rule. Therefore, the term "confined spaces" includes an operator's confined spaces as defined by the OSHA definition and other enclosures designed for temporary occupancy controlled by others. This eliminates uncertainty with respect to the classification of an operator's own facilities. The examples provided in the definition in this final rule are listed as "vaults, certain tunnels, catch basins, and manholes" consistent with the GPTC Guide language, since those types of structures are more likely to be located on and around gas pipeline facilities.

This final rule retains the definition of "gas-associated substructure" as it was proposed. PHMSA determined that changes recommended by the Industry Trades and others were unnecessary based on how the term "pipeline" is defined in part 192. Clarifying that the term refers to an operator's "delivery infrastructure" rather than pipeline is not necessary since the definition of pipeline in § 192.3 is broad enough to include such infrastructure. Additionally, since every portion of a pipeline is designed to transport gas, adding the term transportation to the definition fails to clarify that the definition is intended to address facilities that are not intended to be pressurized with gas.

PHMSA appreciates comments looking to clarify the definition of "lower-explosive limit (LEL)" PHMSA agrees with the comments that the LEL of methane and other flammable gases subject to § 192.760, such as propane, does not change significantly within normal atmospheric conditions, and therefore PHMSA has removed references to ambient pressure and temperature from the definition of LEL in this final rule, and PHMSA does not expect individual LEL recalculations during leak investigations occurring within normal atmospheric conditions. However, if extreme temperature conditions are present in the operating environment of the pipelines, operators should consider how such conditions affect their procedures for performing leakage surveys and investigations in accordance with § 192.763(a)(2). PHMSA disagrees with the comments suggesting it should define leak grades based on percent gas instead of percent LEL, and it has declined to make this change in the final rule. Percent LEL is by definition a measure of potential ignition risk, and PHMSA uses LEL throughout the grading criteria as a measure of the potential risk to public safety from leaks (in combination with other conditions that reflect likelihood of accumulation and proximity to persons and property). Percent gas value fails to capture changes in ignition risk based on the commodity transported or gas composition, and it is therefore a less-direct measure of public safety risk. Since this potential risk necessarily changes based on the physical properties of the gases being transported, operators must calculate the LEL for the gas composition of their systems.

I. Leak Repair and Reevaluation—§ 192.760

1. Summary of PHMSA's Proposal

Prior to this rulemaking, the leak repair requirement in § 192.703(c) only required operators to "promptly" repair "hazardous leaks." The term "hazardous leak" was not defined in subpart M,[350] and neither was the term "promptly."[351] PHMSA therefore proposed to revise § 192.703(c) and establish a new § 192.760 with comprehensive grading and repair criteria with a "schedule for repairing or replacing each leaking pipe, except a pipe with a leak so small that it poses no potential hazard, with appropriate deadlines" in accordance with Section 113 of the PIPES Act of 2020. PHMSA proposed a tiered system of repair deadlines tailored to a leak's potential risk to public safety and the environment.

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[350] Prior to this rulemaking, PHMSA regulations elaborating on the meaning of "hazardous leak" pertained either to entirely different elements of part 192 (specifically, the § 192.1001 definition of ''hazardous leak'' within DIMP requirements in subpart P) or part 191 reporting requirements. See*, e.g.,* PHMSA, Form F 7100.1–1 Instructions (May 2021) (defining hazardous leaks as those representing an "existing or probable hazard to persons or property"). The instructions for annual report forms for other gas pipeline facilities contain similar language.

[351] Section 192.711 allows operators to repair hazardous leaks and other conditions as soon as feasible for non-IM repairs, and as prescribed by § 192.933(d) for IM repairs. If a permanent repair is infeasible, § 192.711 merely requires that any temporary measure addresses public safety, again excluding the environment from explicit consideration.

Grade 1 Leak Repairs

Since a grade 1 leak is the highest priority grade and represents the greatest risk to public safety and the environment, PHMSA proposed that operators must be required to take "immediate and continuous" action to address these risks. Upon detection of a grade 1 leak, an operator must begin instant efforts to remediate and repair the leak and to eliminate any hazardous conditions caused by the leak until the leak repair has been completed (including, but not limited to, those actions identified at proposed § 192.760(a)(2), most of which were already required elsewhere in part 192). The appropriate immediate and continuous actions taken by an operator would necessarily depend on the nature of the leak and pipeline operational and environmental conditions. For example, the immediate and continuous actions required of the operator of a submerged, offshore pipeline when responding to a grade 1 leak on its system may entail different considerations, responsive measures, or repair methods than an operator of an onshore, aboveground, low-pressure pipeline with a grade 1 leak.

Grade 2 Leak Repairs

As discussed above in section III.H, the grade 2 leak classification is intended to capture moderate risks to public safety and the environment that do not necessitate immediate and continuous action but that do merit timely scheduled repair or replacement to address those risks. In the NPRM, PHMSA prioritized repair of certain leaks within the grade 2 classification by proposing a range of repair deadlines based on the level of risk to public safety and the environment. PHMSA proposed a default 6-month repair timeline for grade 2 leaks unless a shorter repair deadline is required by the operator's O&M procedures or IM program.

The NPRM proposed that grade 2 leaks on gas transmission and Type A gathering pipelines within HCAs, Class 3, and Class 4 locations be repaired within 30 days of detection due to the higher consequences of a fire or explosion on these high-pressure lines near people and other HCAs. For these leaks, if repairs could not be completed within the prescribed timeline, the operator would be required to take continuous action to monitor and repair the leak.

Grade 2 Leak Reevaluation

In the NPRM, PHMSA proposed to require operators to periodically reevaluate[352] grade 2 and 3 leaks until repaired to confirm the leaks have not become more hazardous. As proposed, operators would reevaluate most grade 2 leaks once every 30 days, with an accelerated 2-week reevaluation timeline for leaks with a repair deadline of less than 30 days. If a reevaluation indicates that the leak has become more hazardous, such that it now qualifies as a grade 1 leak or otherwise would be required to repair it within a shorter repair timeline (in accordance with § 192.760 requirements or the operator's procedures), the operator would upgrade the leak in accordance with proposed § 192.760(f) and ensure that the leak is repaired on the new timeline, as applicable.

Grade 3 Leak Repairs

PHMSA found that any leak of methane from a gas pipeline system necessarily entails environmental harm proportional to the amount of methane released to the atmosphere, and therefore proposed to require repair of all leaks detectible through ALDPs (see proposed

[352] During a reevaluation, an operator investigates a known leak location to determine if the grade is still appropriate. If conditions with a higher-priority grade are found, then the leak must be upgraded to that higher-priority grade.

§ 192.763). Under this proposal, PHMSA provided a narrow exception from its comprehensive proposed repair requirements for leaks so small as to fall below those minimum equipment sensitivity standards, in accordance with Congress's direction to provide exceptions for "a pipe with a leak so small that it poses no potential hazard," and in recognition that some leaks are so small that the harm they present does not warrant expending the resources necessary to detect and repair them. PHMSA proposed to apply these leak repair schedules for grade 3 leaks on all gas pipeline facilities regulated under part 192 other than UNGSFs.

PHMSA proposed a default 24-month repair deadline in the NPRM for all grade 3 leaks, recognizing that grade 3 leaks present a relatively small but non-zero risk to persons and the environment. Even a small leak can result in significant emissions and harm to the environment and public safety if it is allowed to release indefinitely without repair, and small leaks have the potential to progress to more serious integrity incidents if ignored indefinitely.

Grade 3 Leak Reevaluation

PHMSA proposed to require operators to reevaluate each grade 3 leak at least once every 6 months until the leak was repaired to assess if the leak or the leak environment had changed in a way that may justify an upgrade to a grade 1 or grade 2 leak.

Exceptions for Pipe Replacement Projects

As described in Section II.B.3, certain pipeline segments are known to be leak-prone based on age, material, design, or past operating and maintenance history. In order to incentivize replacement of these problematic segments and thus reduce the likelihood of future leaks on those pipelines, PHMSA proposed an exception from the repair requirement for grade 3 leaks on pipelines that are scheduled for replacement or abandonment, and are in fact replaced or abandoned, within 5 years from the date the leak was discovered. In the interim, the leak would still be subject to periodic reevaluation requirements until the repair is complete.

Extension of leak repair deadlines

PHMSA also proposed to allow operators to extend leak repair deadlines for individual leaks on a case-by-case basis to provide operators with additional flexibility in complying with the proposed repair deadlines. Such an extension would require notification to, and review by, PHMSA pursuant to the procedures at § 192.18. An operator would only be able to request a leak repair extension under § 192.760(h) if: (1) the leak repair pursuant to an alternative schedule would not result in increased public safety risk, and (2) the operator could demonstrate that the prescribed repair schedule was impracticable, an alternative repair schedule would be necessary for safety, or that remediation within the specified time frame would result in the release of more gas to the environment than would otherwise occur if the leak were allowed to continue.

Preexisting Leaks

For grade 2 leaks existing on or before the effective date of the final rule, PHMSA proposed an extended repair deadline of 6 months from the effective date of the final rule (which was, in turn, proposed to be 6 months after publication of the final rule). This extended timeline was intended to give operators flexibility in developing their ALDPs and was consistent with the 12-month grade 2 leak repair schedule in the GPTC Guide. For grade 3 leaks known to exist on the effective date of the final rule, PHMSA proposed an extended repair timeline of 2 and ½ years after the publication date of the final rule to provide operators with additional time to address a potentially significant backlog of preexisting grade 3 leaks while prioritizing more hazardous grade 1 and grade 2 leaks.

Prioritizing Repair of Leaks Within a Grade

The NPRM also proposed to require each operator's leak grading and repair procedures to include a methodology for prioritizing grade 2 leak repairs, including criteria for determining leaks that must be repaired within 30 days or less. PHMSA leveraged criteria from Table 3b of the GPTC Guide with the intent for operators to address those grade 2 leaks with greater likelihood of accumulation or proximity to people. These criteria include the estimated volume of leakage since detection or the date of the last survey (whichever was earlier), migration of gas emissions, proximity of the leaking gas to buildings and underground structures, the extent of pavement, and soil types and conditions that could affect the possibility for hazardous gas migration, such as frost conditions or soil moisture.

2. Summary of Public Comments

General

The MD Attorney General et al. supported the proposed repair timeframes, stating the requirements "strike a middle ground" between the existing GPTC Guide and more stringent State requirements. The PST similarly supported the proposed leak repair provisions, reasoning that PHMSA's proposals appropriately balanced the need for expedient action to address the heightened risks posed by grade 1 and 2 leaks with the need for operator flexibility when making repairs. However, multiple operators opposed the proposed repair requirements and suggested PHMSA retain the current codified leak repair requirements. An industry representative suggested adoption of the current GPTC recommended leak repair deadlines. Operators and the Industry Trades were concerned that the proposed leak repair requirements were too short and would force operators into "reactive leak mitigation," diverting resources away from pipeline replacement activities or other high-impact long-term initiatives.

Rep. Rick Larsen, et al. expressed general support for the leak repair timeframes, including the prioritization of leaks by the risks they pose to the environment and public safety. Physicians for Social Responsibility, Pennsylvania State Senator Katie Muth, Clean Air Council, Waterspirit, a few individual commenters, and individual commenters participating in a letter-writing campaign said that PHMSA should require operators to repair leaks, including grade 3 leaks, within 1 month.

Grade 1 Leaks

Commenters broadly supported PHMSA's grade 1 leak repair proposals. However, some commenters requested that PHMSA clarify aspects of its grade 1 leak proposals. For example, an individual commenter asked PHMSA to further clarify the meaning of "promptly" in the grade 1 leak repair provisions. KOGA asked PHMSA to clarify that immediate and continuous action is only required so long as the hazardous condition persists. Atmos Energy Corporation asked PHMSA to clarify that immediate and continuous action is only required until the repair has been made, and that immediate and continuous action is not required during the period between the repair and the post-repair inspection (recheck).

The Industry Trades, the NGA, and the GPTC requested that PHMSA provide operators with the flexibility to eliminate leaks with "immediate and continuous action" without grading the leaks first, arguing that this approach would be an efficient, and potentially conservative, way to address the most hazardous leaks. These commenters suggested that grading leaks first would delay repair activities.

Grade 2 Leaks

Several commenters, such as the PST and the MD Attorney General et al., supported the proposed grade 2 leak repair timelines. The New York State Department of Public Service supported PHMSA's proposal to shorten grade 2 leak repair timeframes from those set forth in the GPTC Guide. Other commenters asked PHMSA to require repair of grade 2 and grade 3 leaks on even shorter timelines. For example, Physicians for Social Responsibility Pennsylvania, the Clean Air Council, and an individual commenter asserted that all grade 2 leaks should be repaired in 30 days, contending that requiring periodic reevaluation, rather than repair is wasteful and leads to unnecessary pollution.

However, multiple operators expressed concern that the proposed timelines to repair grade 2 leaks were too short. Commenters such as the NGA, the AGA, Energy Association of Pennsylvania, Florida Natural Gas Association, et al., and the Industry Trades argued that the shorter repair timeframe proposed in the NPRM could be impractical for operators to meet due to weather, customer impacts, limited resources (including vendor resources), permitting issues and other access constraints, seasonal disruptions (especially in northern regions), supply chain issues, and personnel safety concerns. These commenters suggested that PHMSA require a 12-month repair timeframe for grade 2 leaks, which they also noted would allow operators to bundle repair and replacement projects more efficiently on the same pipe segment. Williams Companies, Inc. agreed, recommending that PHMSA extend timelines for repair to give operators flexibility to forecast planned outages for customers. Williams Companies, Inc. further noted that bundling would be most cost-effective for operators with small leaks on aboveground appurtenances such as valve operators and stem packings. Other commenters suggested even longer timeframes, such as 36 months. Alaska Oil & Gas Association stated that the proposed grade 2 repair timeframe would disproportionately impact the Alaskan North Slope due to the "sustained cold arctic environment" and the shipping timelines of procuring replacement parts. According to the commenter, some replacement parts "may not even be available within 6 months" of leak discovery since some components must be specially rated for the extreme cold in the Arctic environment and not widely available in stockpiles.

Philadelphia Gas Works raised the Philadelphia-specific concern that the city has a 5-year moratorium on non-emergency work on public rights-of-way that have been recently paved, along with similar moratoria that recur during holiday events and other specified times each year. NiSource Inc. stated that the grade 2 and grade 3 repair and replacement timelines should include the qualification "as soon as practicable" to allow for uncontrollable challenges, such as issues posed by permitting, weather, or parts suppliers. They similarly opposed the proposed requirement for operator to have procedures for prioritizing the scheduling of grade 2 leak repairs in § 192.760(c)(4), particularly the proposal to require operators define 30-day repair criteria, commenting that prioritizing repair of a significant quantity of grade 2 leaks was impracticable. They further argued that the requirement to reevaluate leaks in in proposed

§ 192.760(c)(2) and upgrade if appropriate under proposed § 192.760(f) adequately addresses any need to prioritize grade 2 leaks.

A State regulator requested that PHMSA clarify whether leak grading would be required if an operator repaired all leaks, other than grade 1 leaks, within the grade 2 repair timeframe. The commenter expressed concern about the cost burden of unnecessary grading effort for operators that repair all grade 2 and grade 3 leaks in a timely manner.

PHMSA received numerous comments regarding the investigation or repair of leaks following environmental changes that could affect gas migration. While these comments concerned proposals regarding repair requirements, note that this final rule addresses these concerns via investigation requirements described in section III.J. Multiple operators, the Industry Trades, and industry representatives stated that §§ 192.723(e) and 192.760(c)(5) are redundant requirements for operators to mitigate risks associated with environmental changes. Operators expressed concern with the proposed requirement to repair grade 2 leaks ahead of an environmental change, as most environmental events are unpredictable, and the requirement essentially uprates grade 2 leaks to grade 1 leaks. Philadelphia Gas Works stated that investigating grade 2 leaks in areas vulnerable to environmental changes is more "prudent." Renegade Energy Advisors, LLC urged PHMSA to delay the implementation of the proposed repair requirement for grade 2 leaks following environmental changes to the operating environment that could affect gas migration in § 192.760(c)(5) until GTI, based on a recommendation from the NTSB,[353] releases guidance for responding to leaks during wet

[353] NTSB Safety Recommendation P-21-013. https://data.ntsb.gov/carol-main-public/sr-details/P-21-013

weather conditions on distribution pipelines. Atmos Energy Corporation recommended PHMSA change the repair requirement into a reevaluation requirement, since not all leaks subject to changing environmental conditions will have become hazardous. They also commented that pipeline operating environments and the potential hazards they pose will vary across the country and even across a single system, and therefore recommended referring to changes in environmental conditions that could affect gas migration more generally and permit operators to define what specific conditions would trigger the revised requirements in their procedures. Multiple operators suggested PHMSA remove the requirement to "take immediate and continuous action" from the proposed grade 2 leak criteria. CSU/SMU referenced supporting research to discuss the impact of "snow/ice and heavy rainfall" on "belowground gas transport behavior," which could "increase the hazard potential of the leaked gas."

Grade 2 Leak Reevaluations

PHMSA received several comments from operators and industry trade groups recommending the grade 2 leak reevaluation timelines be extended to 180 days or to 45 days for leaks on a transmission or Type A gathering line in an HCA, Class 3, or Class 4 location. The GPTC commented that the requirement to monitor grade 2 leaks on transmission or Type A gathering lines in HCAs and Class 3 or Class 4 locations was confusing. The Industry Trades, citing information collected from 2 members indicating that less than 2 percent of leaks were upgraded from grade 2 to grade 1, commented that the proposed reevaluation frequency was unreasonable and instead recommended a 6-month reevaluation frequency for grade 2 leaks and a 45-day reevaluation frequency for grade 2 leaks on gas transmission lines.

Grade 3 Leak Repairs

Several commenters, such as the MD Attorney General et al. and the PST supported the proposed grade 3 repair timelines. Others, like Physicians for Social Responsibility Pennsylvania, Clean Air Council, and assorted individual commenters, asserted that the proposed 2-year repair timeframe for grade 3 leaks was too long considering the responsibility that PHMSA has for prioritizing the environmental benefits of pipeline safety.

Still, other commenters suggested that the proposed repair timeframe for grade 3 leaks was too short. Many commenters, including multiple industry trade associations, said that the rulemaking should focus on mitigating larger-emitting leaks rather than requiring repair of all grade 3 leaks. Commenters suggested that PHMSA should allow operators to monitor lower-priority grade 3 leaks instead of requiring their repair. The GPTC, the Industry Trades, the New York State Department of Public Service, and multiple operators proposed that operators should repair grade 3 leaks on an extended timeframe from the 24 months proposed in the NPRM. Commenters proposed longer grade 3 leak repair timeframes ranging from 36 months to 10 years, citing similar concerns with short repair timelines as discussed in the previous subsection. For example, the GPTC recommended PHMSA allow repair of grade 3 leaks within 5 years to provide flexibility to schedule around "community disruption." Others suggested that PHMSA should give operators more flexibility when repairing grade 3 leaks. NiSource Inc. suggested that PHMSA should not set specific grade 3 leak repair timelines but instead allow operators to complete those repairs "as soon as practicable." Commenters such as Philadelphia Gas Works and Spire Inc. expressed concern about the cost burden of repairing small leaks on pipeline segments that might ultimately be replaced. Philadelphia Gas Works was specifically concerned that their customers would be required to pay for the repair of non-hazardous leaks and later would also be required to pay for pipe replacement projects on the same segments.

Some commenters suggested that PHMSA should not require operators to repair grade 3 leaks at all. A small operator anticipated that the proposed requirements would be a financial burden, and that the repair of numerous very small but detectable leaks would be an extremely costly measure to address leaks that have no potential hazard to public safety and minimal impact to the environment. Kinder Morgan, Inc. and the April 2024 Industry Trades comment recommended that PHMSA allow operators to delay leak repairs under a broader set of circumstances, such as situations where a pipeline or process unit shutdown is required, where emissions associated with repair would exceed emissions from delaying the repair, and other similar provisions (relating to technical feasibility, safety, and parts availability considerations, among others) that had been proposed by the EPA in its NPRM regarding 40 CFR part 60, subparts OOOOa through OOOOc.[354] The Industry Trades similarly suggested that a prescribed deadline to repair a grade 3 leak could emit greater emissions than waiting to repair the leak when the pipeline is due for replacement. Kinder Morgan, Inc. suggested that PHMSA should also adopt the EPA's proposed difficult-to-monitor and unsafe-to-monitor provisions. Some commenters went further, such as Ohio Oil & Gas Association, which suggested that PHMSA should only require operators to repair grade 1 leaks and high-emission grade 2 leaks.

[354] Amendments to 40 CFR part 60 subparts OOOOa through OOOOc have since been finalized on March 8, 2024.

Summit Utilities, Inc. commented that PHMSA should focus repair efforts on larger-volume leaks, such as those larger than 10 SCFH (see summary of their comments under the grade 2 leak definition in III.H) rather than prioritize the repair of all grade 3 leaks within 24 months. They further noted that since sensitive ALDP methods could detect more leaks, prioritizing the most significant leaks is necessary to ensure repair requirements are practicable and targeted towards emissions reductions. Southern Company Gas suggested that the 2-year repair mandate for grade 3 leak repairs would divert resources from the replacement of leak-prone distribution lines. An industry representative suggested that environmental impact alone should not justify leak repair, and thus PHMSA should not require the repair of grade 3 leaks that present no safety hazard. The GPTC suggested that PHMSA conform with GPTC guidance and only require operators to repair grade 1 and 2 leaks.

Picarro, Inc. recommended PHMSA allow operators using advanced mobile leak detection technologies capable of quantifying leak rates define a floor for grade 3 leaks that require repair to clearly define actionable leaks and better target grade 3 leak repairs to emissions reductions benefits. They specifically proposed a grade 3 repair criteria of 0.5 SCFH. They cited information from Lamb 2015 and the results of their own surveys to claim that leaks lower than 0.5 SCFH account for less than 6 percent of emissions from gas distribution lines surveyed.

The NGA proposed addressing grade 3 leaks under DIMP, including operator-defined criteria for "actionable emissions risk" that require repair within 24 months, and extended repair timelines for other grade 3 leaks.

Grade 3 Leak Reevaluation

PHMSA received several comments suggesting alternative reevaluation timeframes for grade 3 leaks that ranged from 6 months to 18 months. Annual reevaluation (between 12 to 15 months from discovery), consistent with the GPTC guide recommendations for grade 3 reevaluation, was the most common recommendation. Southern Company Gas requested that PHMSA remove the reevaluation requirement for grade 3 leaks to allow operators to focus resources on higher-risk leaks. The Industry Trades, citing information collected from 2 members indicating that less than 1 percent of leaks were upgraded from grade 3, commented that the proposed reevaluation frequency was unreasonable and instead recommended reevaluation frequencies consistent with the GPTC guide.

Exceptions for Pipe Replacement Projects

Numerous commenters, including the EDF, the American Lung Association, et al., and individual commenters participating in letter-writing campaigns urged PHMSA to remove or shorten the timeframe of the proposed exception for grade 3 leak repairs on pipeline segments replaced within 5 years. The Industry Trades suggested that the replacement project timeline be extended from 5 years to 10 years. Senator Cruz, et al. expressed concern that the proposed 5-year replacement timeline would be of little use to operators because of the long lead time necessary for planning, notification, permitting, and other important steps prior to a pipeline replacement project can be completed. These commenters agreed with the industry trade groups that a 10-year replacement timeline would be more appropriate for this exception.

The Industry Trades generally supported PHMSA's effort to incentivize accelerated cast iron and bare-steel distribution pipeline replacement and repair, reasoning that the replacement and modernization of "aging" pipeline systems can bolster "safety and reliability" but expressed concern that PHMSA's initial proposed exception did not provide enough time for operators to replace leak-prone pipe.

Northeast Ohio Natural Gas Corporation, the AGA, Energy Association of Pennsylvania, Florida Natural Gas Association, et al., Spire Inc., and Philadelphia Gas Works expressed concern about the proposed provisions diverting resources away from pipe replacement and asserted that the rulemaking should grant more flexibility in grade 2 leak repair timelines to accommodate approved or scheduled pipeline replacement projects. Multiple operators and industry representatives asked for PHMSA to provide an exception for repairing grade 2 leaks on pipe segments scheduled for replacement, similar to PHMSA's proposal for grade 3 leaks, with some commenters suggesting that PHMSA should apply a grade 2 leak repair exception for replacement projects scheduled up to 5 years from the date of leak discovery. Other commenters suggested that this exception should be limited to nearer-term replacement projects, such as the GPTC's suggestion that a grade 2 leak on a pipeline scheduled for abandonment or replacement should be reevaluated monthly (not to exceed 6 weeks between evaluations) for as long as 15 months (so long as the operator determines that it is safe to do so).

The GPTC suggested argued that grade 2 leaks on an extended schedule for elimination via replacement could be reevaluated every calendar month, not to exceed 6 weeks between reevaluations.

Extension of leak repair deadlines—§ 192.760(h)

Enstor Gas, LLC and an individual commenter suggested that operators should be able to extend leak repair timelines without notification to PHMSA. The GPTC commented that the proposed grade 3 repair timeline does not allow sufficient time to comply with the extension request in accordance with § 192.18. Other commenters supported the requirement to notify and receive no objection from PHMSA to extend grade 3 leak repair timelines, and many suggested that operators should be allowed to request an extension on grade 2 leak repairs as well.

Preexisting Leaks

The Industry Trades requested that PHMSA allow operators to repair all known grade 2 leaks within 3 years of the effective date of the final rule,[355] instead of within 1 year of the publication date of the final rule as proposed. INGAA requested that PHMSA give operators a 1-year timeline for repairing preexisting grade 2 leaks from the effective date of the final rule instead of the publication date.[356]

Prioritizing Repair of Leaks Within a Grade

Multiple operators requested that PHMSA encourage operators to prioritize the repair of leaks that present public safety hazards over those that do not (i.e., excluding volume or other measures of hazards to the environment).

[355] Since the Associations also requested an effective date 3 years after publication (discussed further in Section III.U below), this adds up to a request that operators have 6 years total after publication of the final rule to repair grade 2 leaks existing as of the publication date.
[356] INGAA similarly requested an effective date of 3 years after publication.

Several commenters opposed the proposed grade 2 leak repair prioritization provisions in § 192.760(c)(4), stating that the provisions would create a "grade 1.5" leak repair category. These commenters argued that an accelerated 30-day repair schedule would be onerous and impractical for operators to implement. The GPTC and multiple individual operators suggested that PHMSA extend the repair deadline from 30 days to 90 days for grade 2 leaks on transmission lines in HCAs, Class 3 locations, and Class 4 locations, with allowances for additional delays in instances where permitting, material acquisition, and system constraints would prevent repair within 90 days. The Industry Trades and other commenters similarly opposed PHMSA's proposal that operators define additional criteria for grade 2 leaks that require priority repair within 30 days. They commented that establishing a single, longer repair timeline for grade 2 leaks would substantially simplify the proposed repair requirements and make the rule easier for operators to implement. Philadelphia Gas works opposed the proposed requirement to have procedures for prioritizing the repair of grade 2 leaks in § 192.760(c)(4), especially the requirement to define 30-day repair criteria. They commented that the existence of immediate grade 1 repair criteria, along with the requirement periodically reevaluate grade 2 leaks, already adequately addresses the risk of grade 2 leaks that may warrant more rapid repair.

3. GPAC Deliberation Summary

The GPAC was briefed on the NPRM with respect to the proposed leak grading, repair, and response requirements in proposed § 192.760 on November 29, 2023, during the first GPAC meeting for this rulemaking. PHMSA's briefing included a presentation of the proposed regulatory language, including a discussion of its costs and benefits, and an overview of material comments from stakeholders on the proposal. Following the briefing by PHMSA staff, the GPAC provided an opportunity for statements from stakeholders in attendance. A private citizen and individuals representing gas distribution, transmission, and gas gathering line operators and trade associations provided comments regarding leak repair and reevaluation requirements. A member of the public urged PHMSA to require the timely repair of all leaks. Representatives from pipeline operators and pipeline trade associations generally requested longer repair timelines for grade 2 and grade 3 leaks. Representatives from operators of distribution systems commented that the proposed repair timelines were impracticable due to seasonal and permitting-related restrictions on maintenance activities. Distribution operators also suggested that the proposed repair exception for pipelines scheduled for replacement within 5 years was too short, arguing that leak-prone pipe replacement programs were decades-long endeavors, and that the repair of leak-prone pipe scheduled for replacement was an inefficient use of resources that sapped resources from pipe replacement programs. A transmission operator suggested extending the grade 3 repair timeline from 2 years to 3 years to provide more time to bundle maintenance activities and therefore reduce cost, customer impacts, and blowdown-related emissions. Representatives from operators and industry trade associations opposed the requirement to repair all grade 3 leaks and commented that failing to clarify that "leaks so small as to post no potential hazard" are excluded from repair requirements was unjustified and contrary to the intent of section 113 of the PIPES Act of 2020. Finally, representatives from pipeline operators opposed reevaluations for grade 2 and grade 3 leaks more frequently than what was recommended by the GPTC Guide since, in their experience, conditions warranting upgrading leak grades were very rare. Comments regarding the cost of repair and other response actions are addressed in the final RIA, which is available in the docket for this rulemaking.

The GPAC deliberated on the proposed leak grading and repair requirements in § 192.760 on November 30, 2023, and recommended revisions to the proposed repair timelines for grade 2 and grade 3 leaks. Discussion and votes on this topic focused on extending the proposed repair timelines, particularly for pipelines that are scheduled for replacement, and on defining which grade 3 leaks should require repair. As noted in section III.H, the discussion on § 192.760 began with a general discussion where some members raised concerns about the potential impacts of adopting Federal leak grading and repair requirements would have on States with existing leak management requirements or pipe replacement programs, and operators and ratepayers in such States. A member representing a State program requested PHMSA consider alternatives or an exception to a minimum Federal standard, such as requiring operators manage leaks under DIMP or approval of State programs that follow the GPTC Guide, but the GPAC ultimately did not vote to recommend such measures.

Carrying over from the discussion of grade 2 criteria described in section III.H, members debated the proposal to require repair of grade 2 leaks within 6 months. A member representing the public expressed strong support for establishing clear repair timelines as proposed in the NPRM, citing emissions modeling provided in their written comments submitted in response to the NPRM that found that the proposed repair timelines could triple emission reductions from gas transmission and gathering systems and double emission reductions from gas distribution systems compared with the status quo. Members representing industry and a State contended that a 6-month repair timeline was impracticable for most grade 2 leaks. Specifically, a member representing a transmission operator cautioned that 6 months was too short for the practicable and net-beneficial repair of grade 2 leaks on gas transmission pipelines, and that repair timelines for such leaks should be no less than a year, if not more. Multiple members described seasonal or permitting restrictions that would prevent an operator from completing repairs within 6 months. Members briefly considered an open-ended requirement to repair grade 2 leaks as soon as practicable; however, multiple members made it clear that a finite limit was required for such leaks. Similarly, members representing operators opposed a proposal to provide an additional 3 months to address seasonality concerns due to permitting restrictions and the impacts of blowdowns. Particularly for leaks that are classified as grade 2 due to emissions, a member representing a gas transmission operator argued that that blowdowns could result in more emissions than are mitigated by the repair and suggested either a repair timeline between 12 and 36 months or the use of a similar approach to the EPA's provisions in 40 CFR part 60, subpart OOOOa.[357]

During the course of discussion, a member representing a distribution operator proposed a repair timeline of 12 months in general, or up to 5 years for pipelines scheduled for replacement. Members representing industry and a State observed that pipe replacement programs were long-term efforts and referred to PHMSA's infrastructure modernization grant program, which is on a 5-year schedule. However, members representing the public and a State

[357] See, for example, 40 CFR 60.5397a(h)(3)(i)), which allows delay of repair until next scheduled shutdown but not to exceed 2 years, and (h)(3)(ii) addressing the availability of spare parts. 40 CFR 60 OOOOb and OOOOc have similar provisions.

were hesitant to consider delaying the repair timeline for grade 2 leaks, including for pipe replacement, due to the potential risk to public safety and the environment. Such members were especially concerned about extending the timeline for grade 2 leaks scheduled for replacement to as long as 5 years compared with the 6 months proposed in the NPRM. A member representing the public provided information showing that while non-expansion capital projects on average took no longer than 280 days on average each year, new projects took even less time, demonstrating that requiring the timely repair of environmentally significant leaks within 12 months was practicable. However, members representing operators cautioned that maintenance projects tend to be more complex than new construction and could not be expected to be completed on the same schedule as greenfield construction projects. A member representing a State described requirements in their State that allow extension of grade 2 leaks up to 2 years for pipe replacement, which gained some support from members representing the public and operators as a compromise addressing both the urgency of repair while recognizing the importance of encouraging pipe replacement as a preventative measure. However, a member representing another State was concerned that defining repair or replacement timelines beyond a general requirement to repair as soon as practicable may not be feasible for all operators in all States, particularly with respect to pipelines scheduled for replacement.

Following discussion on the timelines themselves, members further debated inserting a requirement to repair grade 2 leaks as soon as practicable, but not to exceed the timelines debated in the prior proceedings. Members representing the public and a State were explicit that support for extending repair timelines beyond those proposed in the NPRM as conditional on language ensuring operators repair leaks classified as grade 2 due to their public safety and environmental hazard on a timely basis if it is feasible to do so. Members representing States deliberated on the meaning of "as soon as practicable" but ultimately agreed that it was workable, though they disagreed on the need for defined timelines beyond that. Members representing operators did not oppose this inclusion, and one member representing a distribution operator stated it reflected their current practice with respect to grade 2 leaks, consistent with the GPTC Guide. In the same spirit, members also discussed the proposal to require operators have prioritization procedures for grade 2 leaks, including criteria for leaks requiring repair within 30 days. Members broadly agreed on the value of prioritizing repair of leaks within the grade 2 classification based on the degree of risk to public safety and the environment; however, members representing industry opposed the proposed requirement for operators to define in their procedures a 30-day repair criteria separate from the other grading criteria, arguing the need to do so was addressed by inclusion of "as soon as practicable" in the required repair timeline. Members representing operators desired clarity that the requirement was a procedure-level review of existing procedures for scheduling repairs, and that the agency did not expect documented analysis for each leak scheduled for repair. However, members representing transmission operators did agree that expedited repair for grade 2 and grade 3 leaks occurring on transmission lines in HCAs, Class 3, and Class 4 locations could be considered due to potential risks to public safety.

The final topic on grade 2 leaks concerned the proposed monthly reevaluation requirement. Members representing operators reiterated information brought up by members of the audience concerning the frequency in which leaks are upgraded based on periodic reevaluation and suggested revising the reevaluation frequency for grade 2 leaks to once every 6 months. A member representing the public commented that debate on the reevaluation frequency was important due to the inherent risk of a leak that has become more hazardous. After additional discussion of the 6-month reevaluation frequency in the GPTC Guide and the experiences of operators implementing those guidelines, the GPAC reached a consensus on the recommendation to revise the reevaluation frequency for grade 2 leaks to once every 6 months. Separately, in the context of 30-day repairs for certain grade 2 transmission line leaks discussed previously, GPAC members adopted a recommendation to retain the 2 week "recheck" (presumably referring to frequency of leak monitoring, rather than post-repair rechecks) requirement for leaks that require repair within 30 days without further discussion.

The GPAC discussion on grade 3 leaks focused on defining grade 3 leaks exempted from repair requirements and, similar to grade 2 leaks, schedules for repair or replacement of pipelines with grade 3 leaks. Recognizing concerns raised by members representing the public during the prior discussion of grade 2 leaks, a member representing a gas transmission operator proposed a 12-month repair timeline for leaks on gas transmission lines in HCAs, Class 3, and Class 4 locations, which was adopted in the balloted recommendation. As a continuation of the previous discussion on gas transmission leaks, this recommendation was adopted in the balloted recommendation without significant further discussion.

A significant portion of discussion concerned whether some or all grade 3 leaks should be excepted from repair requirements. Members representing operators and a State described language in the PIPES Act of 2020 mandating rules for a schedule for repairing or replacing each leaking pipe, except a pipe with a leak so small that it poses no potential hazard. A member representing a State commented that bell and spigot joints (a legacy joining method) on cast iron pipe will essentially always have small leaks and questioned if they needed repair if the pipeline was scheduled for replacement. Members representing operators commented that they were committed to eliminating leaks but that strict repair timelines for the least consequential leaks could result in more direct emissions from blowdowns, indirect emissions from disincentivizing replacement, and, particularly for legacy facilities in scheduled replacement programs, an impracticable number of leaks that require repairs. A member representing the public suggested that deferring repair of such leaks could be addressed via the proposed provision for an alternative repair timeline.

A member representing a gas distribution operator proposed a recommendation, similar to what was adopted for grade 2 leaks, to create an exception from repair of grade 3 leaks for leaks with a flow rate less than 5 SCFH; less than 1,000 square feet of leak migration extent; or an alternative equivalent method. A member representing the public stated that they were considering a lower value of 1 SCFH, but over the course of the discussion and debate over the applicability to buried leaks, members representing the public and operators came to consensus around a standard of 5 SCFH. Similar to the discussion of grade 2 leaks, members deliberated on a leak migration extent criteria and alternatives with agency approval, each equivalent to 5 SCFH. While members agreed on 5 SCFH for the leak flow-rate criteria, they ultimately declined to recommend a specific leak migration extent criteria to PHMSA.

Members representing two States opposed this line of discussion and suggested instead that repair of grade 3 leaks could be addressed by requiring operators manage such leaks using a risk-based approach under DIMP with lower impact to ratepayers. A member representing the public acknowledged the need for discussion on actionable leaks but cautioned that members of the public are skeptical of knowingly leaving leaks unaddressed. They further opposed addressing the disposition of grade 3 leaks under DIMP, since the PIPES Act of 2020 directed PHMSA to establish repair timelines. A member representing another State suggested that grade 3 leaks were, by definition, non-hazardous and therefore opposed Federal repair requirements for grade 3 leaks based on language from the PIPES Act of 2020. A member representing an operator stated that the 5 SCFH was intended to establish criteria for non-hazardous leaks.

Regarding the repair timelines for other grade 3 leaks, a member representing the public reiterated their previous support for the proposed 24-month repair timeline for grade 3 leaks, again referring to emissions modeling they had provided in their public comments. They had further concerns with the proposal to allow an extension of repair timelines and requested input from industry members if a longer baseline-repair timeline of 36 months would address the need for ad hoc extensions. Members representing industry and a State commented that additional time was needed for grade 3 leaks to prepare rate plan changes and coordinate maintenance activities to reduce the frequency of high-emitting blowdowns. A member representing a transmission line agreed that 36 months provided a practicable timeline to allow operators to schedule repairs in general and, for transmission lines in particular, to address supply chain limitations for any complex components involved.

The discussion for the repair timelines for grade 3 leaks on pipelines scheduled for replacement proceeded similarly to the parallel discussion of grade 2 leaks. A member representing a distribution operator proposed a replacement timeline of 10 years, compared with 5 years in the NPRM. A member representing the public referred to their previous concerns during the grade 2 discussion and their written comments recommending an additional 12 months for each of the grade 2 and grade 3 repair timelines. Other members representing the public were opposed to extending the repair timeline for pipes scheduled for replacement up to 10 years. Members representing operators and a State reiterated prior comments that they were concerned about undermining leak-prone pipe replacement programs or performing unnecessary repairs. After debate, a member representing a distribution operator proposed 7 years, which members representing industry noted they could support if Committee members recognized that some operators will likely have to request an extension from PHMSA or the State regulator.

A member representing the public suggested adopting the repair prioritization scheme previously discussed in the context of grade 2 leaks. A member representing a transmission and gathering operator agreed, provided the GPAC also addressed repair requirements for leaks below a minimum volume. A recommendation to consider a prioritization scheme for grade 3 leaks was included in the balloted recommendation with consensus.

The final recommendation included a 1-year "reinspection interval." The GPAC did not discuss this interval in its deliberations, but PHMSA presumes this refers to leak monitoring, now referred to as "reevaluation," in the final rule. Similar to the discussion of rechecks in the context of grade 2 leaks, PHMSA observes that this interval is similar to the GPTC Guide, which prescribes a 15-month reevaluation interval.

4. GPAC Recommendation

The Committee did not recommend any changes to PHMSA's proposals regarding grade 1 leak repair timelines.

Recognizing the urgency of repair of grade 2 leaks but also concerns about practicability raised by members, the GPAC recommended revising the repair timeline for most grade 2 leaks to 1 year or as soon as practicable considering environmental concerns and impacts to customers. After further debate, members agreed to compromise on a 2-year timeline for pipelines scheduled for replacement in part based on discussion concerning a similar requirement adopted in the State of Ohio that was found to be practicable to implement. Therefore, members voted 14-1 in favor of the following recommendations regarding grade 2 repair timelines and unanimously in favor of the following recommended revision to reevaluation timelines:

- Repair grade 2 leaks as soon as practicable considering impacts to customers and environmental concerns, but not to exceed 1 year.
- Provide an exception for distribution pipelines scheduled for replacement and that are actually replaced within 2 years.
- Revise the reevaluation frequency for grade 2 leaks to a 6-month interval.

The GPAC considered other aspects of the grade 2 repair timelines. Members generally agreed on the value of establishing a methodology for prioritizing repair scheduling. However, while industry members agreed that leaks on transmission lines in Class 3 and Class 4 locations and HCAs warranted expedited repair, they commented that the requirement for operators to define 30-day repair criteria in their procedures was unnecessary. Based on those discussions, the GPAC unanimously voted for the following revisions to grade 2 prioritization requirements.

- Revise the introductory text of proposed § 192.760(c)(4) to read as follows:
    - (4) Each operator's operations and maintenance procedure must include a methodology for prioritizing the repair of grade 2 leaks. This methodology must include an analysis of, at a minimum, each of the following parameters:[358]
- Move the biweekly recheck requirement for repairs with a 30-day repair timeline to § 192.760(c)(3) [addressing transmission and Type A gathering line leaks in HCAs and Class 3 and 4 locations].

The final recommendation from the GPAC on grade 3 repair requirements, with a vote of 13-2, was:

- For repair timelines:
    - Revise the general repair timeline from 24 months to 36 months.
    - Revise the repair timeline for grade 3 leaks on transmission pipelines in HCA and Class 3 and 4 locations to 1 year.
- For grade 3 Criteria:

[358] In the proposed rule, the parameters included the volume and migration of gas emissions, the proximity of gas to buildings and subsurface structures, the extent of pavement, and soil type and conditions.

- Require repair for grade 3 leaks on distribution pipelines with an emissions rate greater than or equal to 5 CFH, or a leak migration extent method equivalent to 5 CFH, or an alternative method demonstrated to meet the capability of identifying a minimum leakage rate of 5 CFH with a notification to PHMSA in accordance with § 192.18. Repair is required within 36 months unless the pipeline is scheduled for replacement and replaced within 7 years. All other grade 3 leaks are to be reevaluated at a 1-year reinspection interval. PHMSA would evaluate where a leak extent method would be appropriate and equivalent.

▪ PHMSA consider the prioritization process for the elimination of grade 3 leaks.

5. PHMSA Response

General

PHMSA is revising some of the proposed repair timelines and reevaluation intervals based on public comments and recommendations of the Committee. While different commenters argued for both shorter and longer repair timelines, industry commenters and the Committee recommended longer repair timelines for grade 2 and grade 3 leaks, less-frequent leak reevaluation intervals, and broader exceptions from the repair requirements to improve practicability for operators and ensure that operator resources can be focused on the heightened risks posed by grade 1 and grade 2 leaks and on replacement projects that will reduce the likelihood of future leaks. PHMSA appreciates these concerns and recognizes that limited resources and other constraints make an idealized system where operators rapidly repair all leaks impracticable to implement, even if stakeholders agree that such a system would best address the public safety and environmental hazards of gas pipeline leaks. Therefore, PHMSA has provided more flexibility for operators in this final rule, especially with respect to lower-risk leaks, while ensuring that the finalized repair requirements still move the industry forwards from current practice and better meet the need for gas pipeline safety and environmental protection.

Grade 1 Leak Repairs

PHMSA is finalizing the repair requirements for grade 1 leaks as proposed in the NPRM, which were widely supported commenters and the Committee. PHMSA is clarifying a few points in response to comments, such as the meaning of some terms used in § 192.760(b)(2). First, PHMSA confirms that "prompt" repair entails the immediate and continuous actions described in § 192.760(b)(1). Operators are expected to immediately begin response and repair activities upon determining that a leak is a grade 1 leak and continue repair efforts and actions necessary to control present hazards to public safety until the leak is eliminated. In response to comments however, PHMSA has clarified in this final rule that an operator may cease "continuous action" following an attempt at repair but prior to a recheck, provided that an operator confirms through reevaluation of the leak that conditions meeting the definition of a grade 1 leak no longer exist.

As described in the discussion of grade 1 leak criteria from n section 4.2.2.2 and section 4.1.3.2 of the RIA, summarized in section III.H, the requirement to promptly repair Grade 1 leaks reflects baseline practice recommended by the GPTC Guide and required by section 114 of the PIPES Act of 2020. PHMSA did not expect marginal costs or benefits associated with the grade 1 leak repair timeline required in the final rule. To the extent that some Type C gathering line operators do not promptly repair "hazardous leaks," or to the extent that very large gas transmission leaks with a flow rate of 100 kg/hr or more were not being promptly repaired previously, the grade 1 repair requirement could result in additional quantifiable or unquantifiable safety, health, and environmental benefits.

PHMSA disagrees with concerns raised by commenters that the requirement to establish a grade could delay the repair of hazardous grade 1 leaks. Leaks that are so obviously hazardous as to be apparent to operator personnel prior to conducting grading activities can and should immediately be designated as grade 1 leaks under the criterion in § 192.760(b)(1)(i) ("any leak that, in the judgment of operating personnel requires immediate repair"). This determination can be made without further investigation or grading activities and therefore does not delay response action. Finally, nothing in § 192.760 prevents an operator from initiating response activities until a grade determination is made. Operators may similarly elect to promptly repair all leaks when found without the need for further grading activity, effectively treating all discovered leaks as grade 1 leaks. For further information on how to characterize leaks when an operator promptly repairs all leaks when found, see the discussion of reporting amendments in section III.L and the final annual report form instructions for guidance.

Grade 2 Leak Repairs

As noted above, PHMSA is extending some of the proposed repair timelines and reevaluation intervals based on public comments and recommendations of the Committee. For grade 2 leaks, in this final rule, PHMSA has adopted the GPAC recommendation to extend the general repair schedule for most grade 2 leaks from the proposed 6 months to 12 months. While extending the repair deadline could increase the duration of a given leak, operators will still generally be required to repair grade 2 leaks within a year (consistent with common practices described in the GPTC Guide, which recommends eliminating leaks within one calendar year, but no later than 15 months from the date the leak was reported). PHMSA expects that operators will find such a timeline much more practicable to implement considering potential seasonal disruptions, customer impacts, permitting issues and access concerns, limited operator and vendor resources, and other constraints expressed by commenters and the Committee. For these same reasons, this final rule does not adopt recommendations to shorten the timeline for repair of grade 2 leaks. Depending on when leaks were identified during a given year, a 6-month repair timeline could be particularly difficult for operators to meet in northern regions during the winter (especially in the Alaskan North Slope), both because of freezing conditions that could make performing repairs challenging and because of potentially greater customer impacts due to higher gas demand for heating needs during the winter. A longer repair timeline for many grade 2 leaks will reduce costs, operational challenges, customer impacts, and potentially even total emissions by increasing opportunities for operators to coordinate repair tasks with other planned maintenance activities (project bundling) and therefore reduce the frequency at which a given pipeline needs to be shut down or vented. PHMSA further expects that this change should alleviate concerns from commenters about pipeline-specific, temporary conditions that can impact leak repairs, such as restrictions on access to a pipeline facility due to roadwork limitations or other conditions outside of the operator's control. For pipelines located in the Alaska North Slope, PHMSA expects that the changes made in this final rule to extend grade 2 leak repair timelines and reduce survey frequency will help ensure that, in most circumstances, an operator will not be required to perform grade 2 leak repairs during the winter months.

Compared with the proposed rule, the repair timeline for grade 2 leaks more closely corresponds with the repair requirements for grade 2 leaks described in the GPTC Guide. Accordingly, section 4.1.3.1 and 4.2.2.1 assumes that, with the exception of the emissions criteria, the grade 2 criteria adopted in the final rule reflect the existing practices for operators of gas distribution, gas transmission, and Type A regulated gas gathering. On the other hand, the RIA assumes no baseline compliance with grade 2 repair requirements for operators of Type B and Type C gathering lines, though PHMSA notes that some larger-diameter Type C gathering lines currently subject to leakage survey requirements may have adopted grade 2 repair requirements due to the higher operating stress compared with Type B lines or due to State requirements. Requiring repair of leaks on such lines within 12 months results in quantified environmental benefits and unquantified public health and safety benefits, but results in higher repair costs. For leaks that would have been categorized as grade 3 under the GPTC guide but that are classified as grade 1 leaks under the flow-rate criteria, the repair timelines in the final rule generate quantified environmental benefits from eliminating emissions sources and unquantified safety, environmental, and public health benefits. As described in section III.H, PHMSA considered an alternative that excluded emissions-based criteria and grade 3 repair requirements, however that alternative foregoes quantified net benefits and unquantified safety benefits associated with scheduled repair of leaks with an intermediate level of risk to public safety and the environment.

PHMSA appreciates comments supporting environmentally cognizant grading criteria and requesting that large-volume releases still be repaired upon prioritized timelines. As discussed in section III.H, PHMSA is finalizing a leakage-rate criterion for grade 1 leaks (any leak with a leakage rate exceeding 100 kg/hr), thus ensuring that the hazards presented by "super-emitting" leaks will be promptly remedied.

PHMSA agrees with comments from the Industry Trades and others that the requirement for operators to immediately complete the repair of grade 2 leaks following environmental changes that could affect gas migration was unnecessary and conflicted with a separate proposal to investigate known leaks on gas distribution lines under similar circumstances proposed in § 192.723. Therefore, in this final rule, and as discussed previously in this section, PHMSA is combining these requirements into a general requirement in § 192.760 for operators to investigate known leaks. This is described in greater detail in section III.J.

Consistent with the GPAC recommendation, PHMSA retains the accelerated repair timeline of 30 days for grade 2 leaks on gas transmission or Type A gas gathering lines in Class 3 and Class 4 locations and gas transmission lines in HCAs. Section 192.760(c)(4) requires an operator to complete a repair within 30 days of discovery; however, a repair may be extended to being completed "as soon as practicable" if the repair cannot be completed within 30 days due to permitting requirements or parts availability. If an operator does not complete the repair within 30 days, the operator must reevaluate the leak once every 2 weeks. Gas transmission and Type A gathering lines in HCAs and Class 3 and Class 4 locations are, by definition, high-pressure lines operating in densely populated areas. Due to the elevated potential consequences to public safety should a leak from such a line result in a fire or explosion, prompt repair is justified. This final rule allows an operator to complete repair as soon as practicable beyond 30 days due to parts availability and permitting concerns, consistent with delay-of-repair provisions in EPA emissions monitoring requirements, which has a similarly short default repair timeline. The EPA delay-of-repair provisions are described in greater detail in the responses to the comments regarding extending leak repair timelines. However, as described below in the discussion of scheduling leak repairs, this final rule does not include the requirement for operators to define in their procedures 30-day repair criteria for certain grade 2 leaks. Finally, this accelerated repair requirement does not apply to leaks classified as grade 2 by default under § 192.760(c)(1)(vii) or due to emissions under § 192.760(c)(1)(ix) but that do not meet any of the other grade 2 criteria; such leaks are instead subject to the default repair timeline for grade 2 leaks.

Regarding the discussion in section III.H.5 regarding operators who determine all leaks as grade 1 leaks by default, an operator may use the "judgment of operating personnel" criterion at § 192.760(c)(1)(x) to classify all discovered leaks as grade 1 or grade 2. In other words, an operator who repairs all leaks, other than grade 1 leaks, on a grade 2 timeline would not be required to differentiate between grade 2 or a grade 3 leak. This practice was permitted in the NPRM and, as clarified, should address concerns commenters raised regarding operators performing unnecessary grading activity if they repair all leaks on a grade 1 or grade 2 schedule.

Grade 2 Leak Reevaluation

PHMSA is similarly extending the reevaluation timeline for most grade 2 leaks to a 6-month interval, consistent with common industry guidance described in the GPTC Guide. The purpose of the reevaluation requirement is for operators to help ensure that existing leaks have not become more hazardous. For example, a grade 2 leak could progress into a grade 1 leak if gas has started accumulating inside of buildings due to changes in environmental conditions or if the failure that caused the leak has worsened. Data submitted by commenters and described during the GPAC deliberations indicated that leak upgrading through reevaluation was rare, but that the risk of a leak becoming more hazardous was non-zero. Therefore, while this final rule retains requirements to reevaluate leaks periodically and following changes to the leak environment that could case gas to migrate into nearby buildings (see § 192.760(f) and section III.J), PHMSA has adopted longer intervals for periodic leak reevaluation as recommended by public comments and consistent with guidance in the GPTC guide. Other existing and newly finalized requirements, such as the investigation of known leaks following changes to environmental conditions that affect gas migration (§ 192.760(f)) or additional leak surveys following extreme weather events (§§ 192.613(c) and 192.723(d)), are better targeted at those specific situations where existing leaks are most likely to become more hazardous.

Consistent with the GPAC recommendation and recommendations from public comments, this final rule requires an operator to reevaluate grade 2 leaks on gas transmission lines in HCAs and gas transmission or Type A gathering lines in Class 3 or Class 4 locations that meet any of the grading criteria in § 192.760(c)(1)(i) through § 192.760(c)(1)(vi) and § 192.760(c)(1)(xi). Leaks on such pipelines that are classified as grade 2 by default under § 192.760(c)(1)(vii) or due solely to emissions under § 192.760(c)(1)(ix) are subject to the standard reevaluation frequency applicable to all other grade 2 leaks. Due to the elevated consequences of a fire or explosion from a leak on a high-pressure pipeline in these locations, more stringent standards for monitoring leaks with potential ignition hazard are appropriate.

Section 4.1.3.5 and section 4.2.2.5 address the costs of leak monitoring. PHMSA estimated leak monitoring costs of $219 per leak reevaluation for gas transmission and regulated gas gathering lines and $109 per leak reevaluation for gas distribution lines. In the RIA, PHMSA assumes that transmission and gathering operators reevaluate leaks every other year and that gas distribution operators monitor leaks in accordance with the GPTC guide. PHMSA expects unquantified safety and environmental benefits associated with the detection and upgrading of leaks that have become more hazardous since the original grade determination due to changes to the leak or changes to the leak environment that caused either the flow rate or rate of gas accumulation to change.

Grade 3 Leak Repairs

For grade 3 leaks, PHMSA is extending the general repair timeline for most grade 3 leaks from a proposed 24-month period to 36 months in this final rule. In this final rule, PHMSA is also exempting the smallest and least-hazardous leaks from any repair requirements, in accordance with congressional direction in Section 113 of the PIPES Act of 2020 (discussed in further detail in section III.T) and in response to input and recommendations from commenters and the Committee. Operators will not be required to repair leaks that meet any of the following characteristics: (1) grade 3 leaks with a measured or calculated emissions rate of less than 5 SCFH; (2) below-ground grade 3 leaks on a pipeline operating at less than 20 percent of SMYS with a measured leak extent area of less than 1800 square feet; or (3) grade 3 leaks determined by an alternative method to be equivalent to a measured or calculated emissions rate of less than 5 SCFH permitted with advanced notification to, and no objection from, PHMSA in accordance with § 192.18.

With these final grade 3 leak repair provisions, PHMSA is giving operators even further flexibility in this final rule to focus their LDAR efforts on the leaks on their systems that present the most significant hazards to public safety and the environment. PHMSA appreciates the wide range of comments on the proper timeline for grade 3 leak repairs and acknowledges that some commenters recommended that PHMSA not require repair of any grade 3 leaks. However, even relatively small leaks can represent a hazard to the environment when permitted to release indefinitely; similarly, numerous small leaks can add up and have an actionable environmental impact in the aggregate. While the Committee recommended that PHMSA specifically provide an exception for the least hazardous leaks on distribution lines, PHMSA is also excluding the smallest leaks on transmission and gathering lines from repair requirements because a leak representing a minimal release from a distribution system also represents a minimal release for a gas transmission or regulating gas gathering system. In addition, stakeholder comments during the GPAC meeting described the environmental and costs associated with stopping and blowing down gas transmission pipelines for accelerated repair of sub-5 SCFH leaks from valves and other components. Exempting the smallest leaks from the repair requirements of this final rule (at a threshold level significantly higher than the 0.04 SCFH in the lifecycle emissions calculations for repair provided by the Industry Trades comment) combined with this rule's extended repair timelines addresses comments from industry representatives that repair of some, or all, grade 3 leaks was counterproductive. Specifically, these changes screen out the least-consequential leaks and provide additional time for operators to schedule leak repairs with other planned maintenance activities, reducing or eliminating the need to vent the pipeline. Finally, the changes reduce impacts on near-term pipe replacement programs that can provide long-term benefits by reducing the frequency of leaks in the first place.

PHMSA is adopting these grade 3 leak repair provisions in part because of improved grade 1 and grade 2 criteria in this final rule that better capture the public safety and environmental risks from larger-volume leaks. These modifications mean that the category of grade 3 leaks under this final rule will present fewer risks overall, thus reducing the need for near-term repairs. While allowing leaks to persist for a longer period will lead to additional emissions from those leaks, PHMSA has determined that this final rule's repair provisions properly balance this impact with the costs, customer impacts, and other burdens of leak repair requirements. To the extent that operators leverage the flexibility that PHMSA has provided in this final rule to bundle pipe repair and other maintenance activities, thus reducing the number of planned blowdowns, or to replace leak-prone pipe segments, these avoided emissions will offset the additional emissions from less-stringent repair requirements.

This final rule adopts the Committee-recommended 5 SCFH leak-rate threshold (or an equivalent with notification to PHMSA in accordance with § 192.18), below which operators do not need to repair grade 3 leaks. PHMSA reviewed data on the distribution of emissions from gas distribution pipelines by individual leak size and found that a 5 SCFH repair threshold is likely to lead to the eventual elimination of the majority of gas distribution emissions by volume, although these distributions do vary depending on the sample of leaks being evaluated. For example, leaks measured under the Lamb 2015 study found that over 50 percent of emissions were attributable to leaks with an emissions rate greater than approximately 0.3 kg/hr (approximately 15 SCFH), which would be repaired under PHMSA's requirements in this final rule. Similarly, data provided by Picarro, Inc. during the course of this rulemaking[359, 360] indicates that the 5 SCFH repair threshold would eliminate approximately 63 percent of emissions from gas distribution systems. Picarro, Inc.'s data is derived from 4 million gas distribution leaks detected on customers' systems. Picarro, Inc. had recommended that PHMSA establish a minimum repair criterion of 0.5 SCFH for grade 3 leaks to eliminate the majority of emissions. However, compared with the 5 SCFH threshold, Picarro, Inc.'s recommendation would eliminate 93 percent of emissions but would require 6 times as many repairs. Therefore, in this final rule, PHMSA is adopting the more cost-effective threshold of 5 SCFH that will still address most gas pipeline leak emissions. To provide operators with clarity on the applicable timelines for permanent repair following a temporary repair, and to incentivize permanent repairs, leaks that were downgraded to grade 3 following an attempt at repair in accordance with § 192.760(i)(1) are not eligible for this exception from the repair requirements.

The repair timeline for grade 3 leaks and repair exception for leaks with a flow-rate less than 5 SCFH results in lower quantified environmental benefits compared with the 24-month repair requirement for all grade 3 leaks (pipe replacement extension notwithstanding) proposed

[359] Picarro, Inc. August 15, 2023. (PHMSA-2021-0039-24679)
[360] Picarro, Inc. May 6, 2024. (PHMSA-2024-0005-0403)

in the NPRM. However, since grade 3 leaks, particularly grade 3 leaks with a flow rate less than 5 SCFH represent relatively small release events, costs decrease at a greater rate than benefits. Section 2.2.6 of the RIA includes an evaluation of an alternative that does adopts repair requirements more similar to those in the GPTC guide, including eliminating the requirement to larger grade 3 leaks. This alternative resulted in notable reductions in quantified benefits, and benefits were estimated to decrease more rapidly than costs. In comparison, alternative 2 described in section 2.2.2. of the RIA, including the shorter 24-month repair timeline and the requirement to repair all grade 3 leaks, results in higher environmental and public health benefits, but substantially higher costs, resulting in lower quantified net benefits. While most of the increase in cost is due to the more frequent leak survey, patrol, and reevaluation frequencies proposed in the NPRM, accelerating repair of relatively small leaks is less cost effective than addressing more significant emissions sources. In addition to the sensitivity analysis PHMSA considered a sensitivity analysis considering different repair costs based on information provided in public comments, which still results in a rule with positive quantified net benefits for each type of facility covered.

PHMSA acknowledges that the repair threshold for grade 3 leaks is below the minimum equipment sensitivity required for operators electing to use screening surveys (described in detail in section III.D). However, as discussed above, while the requirements of this final rule do not obligate operators to demonstrate that their ALDP systems will detect every leak of 5 SCFH, PHMSA expects that those operators electing to use screening surveys will nonetheless still detect small leaks through several different avenues, including leak surveys or patrols where operating personnel happen to find small leaks, and odor calls from the public. Thus, the grade 3 repair thresholds in this final rule are necessary for operators to know how such leaks must be addressed when detected.

To provide operators with flexibility in equipment choice and procedure design, this final rule will alternatively allow operators to determine whether a grade 3 leak must be repaired based on a leak extent threshold of 1,800 square feet for below-ground leaks on pipelines operating at less than 20 percent of SMYS. The Committee recommended that PHMSA consider a leak extent method for applying a grade 3 leak repair exception but did not recommend any specific criterion. However, PHMSA received comments recommending that 1,800 square feet was an appropriate threshold.[361] Commenters cited research indicating that release rate is correlated with leak extent,[362] suggesting that a leak extent area of 1,800 square feet is consistent with an emissions rate between 4 and 5 SCFH. Therefore, after reviewing said research PHMSA is adopting 1,800 square feet as a rough proxy for leaks of 5 CFH, which, as noted above, is a cost-effective threshold to capture most gas pipeline emissions. Similar to the leak extent criteria for grade 2 leaks, this criterion may only be applied to leaks originating below ground on pipelines operating at less than 20 percent of SMYS. The leak extent method will not properly reflect all leaks, since on an aboveground leak, those leaks result in little to no gas accumulation in soil. Additionally, the research supporting the leak extent criteria was focused on gas distribution lines, and the results may not be applicable to pipelines operating at higher pressures.

[361] E.g., (PHMSA-2024-0005-0387).

[362] Magavi, Zeyneb Pervane. "Identifying and Rank-Ordering Large Volume Leaks in the Underground Natural gas Distribution System of Massachusetts," (May 2018). http://nrs.harvard.edu/urn-3:HUL.InstRepos:37945149.

For example, increased velocity of gas flow from a leak on a high-pressure gas transmission line may likewise prevent absorption in soil and impair the value of the leak extent method as a proxy for flow rate. PHMSA appreciates concerns from public comments submitted following the GPAC meeting on adopting the leak extent criteria for this purpose, however in the absence of an alternative method, operators using most types of handheld leak detection equipment, including most gas distribution operators, would likely be unable to apply this exception without individual operator approval under § 192.18. PHMSA will monitor the implementation of the leak extent method for both the grade 2 and grade 3 criteria and propose changes if the method fails to adequately identify larger-volume leaks or if changes in technology render the relatively imprecise leak extent method unnecessary.

The final rule requires operators to annually reevaluate grade 3 leaks that are exempt from repair requirements to determine whether those leaks have become more hazardous and now must be repaired under § 192.760(d), or whether they must be upgraded to grade 1 or grade 2 in accordance with § 192.760(h). Additionally, this final rule requires gas distribution operators to report the number of leaks not scheduled for repair on their annual reports to PHMSA so that PHMSA and the public can evaluate the impact of this repair exception and have a complete picture of the universe of leaks on gas pipeline systems. PHMSA encourages operators to repair these smaller, less-hazardous grade 3 leaks, or replace the affected pipe during planned system outages, rather than simply allowing those leaks to persist indefinitely.

Grade 3 Leak Reevaluation

PHMSA is extending the reevaluation timeline for grade 3 leaks to 12 months, for both grade 3 leaks that must be repaired and those that may simply be monitored without repair. This is a similar timeline to the timeline currently required under the GPTC Guide (the earlier of 15 months or the next scheduled survey). PHMSA does not agree with some comments that grade 3 leaks require no reevaluation. As noted above, the purpose of leak reevaluation is to help ensure that leaks do not worsen and become more hazardous. Data submitted by commenters indicates that, while not common, operators do discover that some leaks have become more hazardous over time. Operators must reevaluate grade 3 leaks periodically to ensure that, if the leak now meets grade 2 or even grade 1 criteria, the operator will address the heightened risk appropriately. Moreover, smaller grade 3 leaks may grow to the point where they must be scheduled for repair. Refer to the discussion of grade 2 leak reevaluation above and the RIA for information on the costs and benefits of reevaluating known leaks.

Exceptions for Pipe Replacement Projects

This final rule adopts the GPAC recommendation to extend the timeline for the proposed pipe replacement project exception for grade 3 leaks. Operators will not be required to repair grade 3 leaks on pipeline segments scheduled for replacement (and that are actually replaced) within 7 years of leak identification. PHMSA acknowledges that pipe replacement programs can be long-term projects with significant lead time required for planning, permitting, and other steps in the replacement process, and a 7-year exception should further incentivize operators to complete replacement projects, especially on leak-prone segments. However, PHMSA disagrees with comments suggesting that a 10-year timeline is necessary to make this pipe replacement program exception useful for operators. Pipelines scheduled for replacement in the near future (insofar as 7 years constitutes the near future) still enjoy the benefits of the extension for repairs. Some pipe replacement projects may be scheduled many years in advance; however, this proposed extension was intended to reduce cost and unnecessary effort regarding pipelines that were scheduled for repair in the near future, not as an open-ended exception for repair for any pipeline that may be replaced. This extension was never conceived of as a replacement deadline, and PHMSA does not expect every pipe replacement program to be completed within 7 years. However, PHMSA does expect an operator to repair, or eliminate via replacement or formal abandonment, leaks in a timely manner as set out in this final rule. PHMSA aims to balance the value of planned pipe replacement projects with the need for near-term leak repairs (as expressed by many commenters recommending that PHMSA shorten or eliminate this replacement project exception); a 10-year timeline would conflict with the intent of the rulemaking by allowing for excessive deferral of leak repairs.

PHMSA is also adopting the GPAC-recommended exception for grade 2 leak repairs on gas distribution lines that are scheduled for replacement, and that are actually replaced, within 2 years of the discovery of the leak. Again, PHMSA seeks to leverage the value of replacement projects as an effective long-term solution for pipeline leaks, which can be especially impactful for gas distribution systems composed of cast-iron and other leak-prone pipe materials, with the negative short-term impacts of delayed leak repairs. The Committee recommended, and PHMSA is adopting in this final rule, a much shorter window for this exception than the grade 3 exception because of the heightened safety and environmental risks of grade 2 leaks. However, PHMSA expects that this is one more way in which this final rule provides flexibility to operators to focus their resources on the most cost-effective efforts to reduce gas pipeline leaks.

Extending Leak Repair Timelines

The NPRM proposed an operator would be able to request an extended repair deadline for grade 3 leaks where there was a strong safety or emissions reduction justification for delaying repair or when there were obstacles to timely repair that are outside of the operator's control. This final rule does not adopt this proposed notification and repair extension review. Conflicting comments called for no extensions to be considered, extensions with no notification requirements, or expanding the scope of the extension to grade 2 leaks. This final rule modifies the grade 3 leak repair criteria to include periodic reevaluation of leaks that must be monitored but may not require repair and a repair timeline that has been extended from 24 months as proposed in the NPRM to 36 months. Similarly, this final rule extends the repair timeline for grade 2 leaks to 12 months. Each of these repair timelines were found to be practicable during GPAC deliberation and were supported in public comments from industry stakeholders. These conditions should make leak repair practicable in most situations. As a result, PHMSA no longer believes that the provision for extending repair timing via a notification under 192.18 is necessary. This change reduces the anticipated burden on operators and PHMSA for the preparation and review of notifications, helps ensure a consistent standard for leak repairs, and keeps the notification program in § 192.18 focused on approvals for alternative compliance methods, rather than exceptions more appropriately addressed under PHMSA's special permit program. This change renders the timeline for no objection under § 192.18(c) moot for this purpose.

PHMSA acknowledges there may be a rare instance where this repair timeline is impractical, and if that occurs operators may apply for an emergency special permit as detailed in § 190.341 or a State waiver under 49 U.S.C. 60118, as appropriate. During GPAC deliberations, members raised specific concern about some instances where a 7-year repair timeline for grade 3 leaks scheduled for replacement may require ad hoc extensions. To the extent that an alternative pipe replacement program could achieve an equivalent or greater level of pipeline safety and environmental protection compared with the prescribed repair requirements, that can be accommodated via the existing special permit and State waiver mechanisms. PHMSA acknowledges that special permit and State waiver approval is a lengthier process compared with the § 192.18 notification process; however, the revised timelines provide ample time to submit requests for approvals, particularly for grade 3 leaks scheduled for replacement, which was the main area for concern. The special permit and State waiver process also addresses concerns raised in public comments and by members during the GPAC meeting. First, each special permit or State waiver requires review and approval, and existing procedures make information about special permits and State waivers available to the public, addressing key points of concern from public advocacy groups. Additionally, unlike objections to § 192.18 notifications under § 192.18(c), State program managers share decision-making authority in the State waiver process, addressing strident concern from some GPAC members about undermining the role of State program managers. Finally, unlike the proposed notification requirement which was an ad hoc request per leak, special permits or State waivers can be more flexible with respect to their scope; a fact that is likely to be advantageous to the older, larger operators that carry a disproportionate inventory of leak-prone pipelines subject to a 3- or 7-year repair timeline for grade 3 leaks.

PHMSA likewise did not incorporate a delay of repair provisions mirroring those in the EPA emissions monitoring requirements, such as at 40 CFR 60.5397b(h). At a baseline, for each fugitive emissions source found with leak detection equipment, the EPA requires an operator to make a first attempt at repair within 30 days and complete repair within another 30 days. The EPA repair standard, which applies to all covered fugitive emissions, is stricter than any repair timeline adopted for grade 2 or grade 3 leaks in this final rule, except for grade 2 leaks on gas transmission or regulated gas gathering lines in HCAs or Class 3 or Class 4 locations, for which PHMSA has provided delay of repair provisions for permitting and parts availability issues. The EPA permits a delay of a repair if the repair is technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, but such a repair must be completed during the next scheduled shutdown or within 2 years of discovery, whichever is earliest. Assuming an operator does not shut down the facility within a year, this provision provides up to an additional year to complete a repair compared with the repair requirement for grade 2 leaks. However, the characteristics of grade 2 leaks from gas pipelines regulated under part 192 justify the absence of a delay provision. Unlike fugitive emission components, which are virtually always located within operator-controlled property, part-192 regulated gas pipelines are often located in public places and pose potential risks to public safety in addition to the environment. Additionally, 9 out of 11 of the grade 2 criteria PHMSA is finalizing in this rulemaking involve flammability risks and other considerations of potential public safety risk, and relatively large releases from pipelines can similarly pose a risk to public safety. Further, multiple States have adopted the GPTC repair timelines for grade 2 leaks, demonstrating the practicability of repair of such leaks within 1 year. For grade 3 leaks, the repair timeline in § 192.760 is 3 years, compared with a potential maximum of 2 years under the EPA's delay of repair provisions in 40 CFR 60.5397b(h)(3). Accordingly, any change in this final rule on this basis is moot.

The EPA also permits a delay of repair in the case of parts availability issues. PHMSA has provided a similar provision for certain grade 2 leaks subject to a 30-day repair requirement; however, for all other leaks, PHMSA expects that 1 year or more provides a more than reasonable amount of time for an operator to order and procure replacement parts.

Preexisting Leaks

PHMSA appreciates concerns raised by operators of the potential burden for operators to grade or regrade leaks that are known to exist on their systems before the compliance date of this final rule. As described in greater detail below, this final rule provides additional clarification on managing leaks discovered prior to the compliance date of the rule and does not require operators to regrade most leaks discovered prior to the compliance date of the rule. The burden of re-investigating and grading the backlog of existing leaks was one of the main justifications raised by commenters for extending the effective date of this final rule. As described in the preamble of the NPRM and in section II.C.3, the backlog of existing leaks on a given operator's system could be substantial, depending in part on the quality of an operator's recordkeeping for grade determinations and how their procedures for leak grading differ from the criteria and timelines finalized in this rulemaking. Some operators will have few leaks in their backlog as they regularly repair all leaks discovered; others may have a large backlog if they never repair grade 3 leaks.

Considering these and other concerns, PHMSA has significantly extended the proposed compliance deadlines in this final rule (see detailed discussion in Section III.U). Moreover, PHMSA has extended the proposed repair timelines for leaks existing on or before the compliance deadline of January 1, 2028, to improve operators' ability to implement the grading criteria set forth herein and apply those criteria to existing leaks as needed.

Specifically, for leaks existing prior to January 1, 2028, operators must either comply with the requirements in § 192.760 or alternatively, grade, reevaluate, and repair existing leaks known to exist or discovered prior to the compliance date of this final rule in accordance with the operator's procedures and applicable Federal (i.e., § 192.760(c) as it existed before this rulemaking) and State requirements existing on **[insert date of publication of the final rule]**. Leaks known to exist that have been graded under the operator's procedures do not need to be regraded; however, leaks discovered between the effective date of the rule (**[insert effective date of the final rule])** and January 1, 2028, must be graded and managed accordance with those existing procedures or in accordance with § 192.760. For grade 2 leaks or leaks with an equivalent moderate-priority classification, operators must complete these repairs no later than 1 year after the compliance date of the rule (i.e., by January 1, 2029) or as specified in the operators' procedures, whichever date is earlier. This will help ensure that moderate-risk leaks are repaired in the near term without forcing operators to first regrade existing leaks in accordance with the revised requirements.

For all other leaks, the operator must reevaluate the leak no later than January 1, 2029, and have a grade established in accordance with this final rule's § 192.760 requirements. These remaining leaks must then be managed in accordance with the requirements in § 192.760 and repaired in accordance with deadlines set forth in § 192.760 unless the operator's procedures require an earlier repair date. For the purposes of establishing timelines for reevaluations and repairs, the date of discovery for these legacy leaks is the date that a grade was established under § 192.760(a)(3)(iii).

Delaying the requirement to make revised grading determinations on an operator's backlog of existing leaks will reduce the upfront compliance burden of this rulemaking and allow operators to focus their resources during the phase-in period of this final rule on complying with existing industry and State leak management standards, developing their ALDP and procedures, and preparing for full compliance with new leak grading and LDAR requirements beginning on January 1, 2028.

Prioritizing Repair of Leaks Within a Grade

PHMSA is generally finalizing the proposed grade 2 leak repair prioritization process and extending it to grade 3 leaks as well because of the added clarity that it can provide for operators looking to direct resources to the most hazardous leaks within each grade. This entails having and following a methodology for scheduling repairs based on factors indicative of potential risks to public safety and the environment, including the migration and estimated volume of gas emissions, proximity to buildings and subsurface structures, pavement extent, soil conditions, and scheduling with other planned maintenance and repair activities. This prioritization system is based on existing widespread industry practice under the GPTC Guide, supported by Committee recommendations, and recognizes that a 3-grade system is not particularly discrete; leaks can present a range of hazards even within a single leak grade. Operators can likewise incorporate existing analyses prepared under gas transmission or distribution integrity management programs. This amendment directs operators to prioritize within each grade repair and remediation efforts that would have the greatest impact on safety and environmental outcome with relatively minor upfront effort that builds on existing IM requirements and industry practices.

To address commenter concerns, PHMSA has simplified the prioritization requirement for operators by moving the requirement into § 192.760(e), such that it now applies generally to both grade 2 and, consistent with recommendations from the GPAC, grade 3 leaks. While grade 3 leaks do not pose as significant a risk compared with grade 2 leaks and above, there is still a benefit for operator to focus on eliminating those leaks with the greatest potential impacts to public safety and the environment when scheduling repair activities. This approach clarifies that operators can use a single set of procedures for planning when to schedule repair of grade 2 and grade 3 leaks, simplifying implementation. Since PHMSA has now adopted a quantified leak rate criterion for grade 1 leaks and has otherwise provided specific direction for operators on which grade 2 leaks are so hazardous that must be repaired within 30 days (i.e., those grade 2 leaks occurring on gas transmission lines in HCAs and transmission and Type A gas gathering lines in Class 3 and Class 4 locations), this final rule does not require operators to separately define their own 30-day repair criteria under this requirement. While this final rule does not require repair of all grade 3 leaks, this requirement establishes factors that an operator should consider when scheduling repair of larger grade 3 leaks and determining whether smaller grade 3 leaks should be scheduled for eventual repair or replacement.

J. *Leak Management (Investigation, Repair Rechecks, Upgrading, and Downgrading)—§ 192.760*

1. *Summary of PHMSA's Proposal*

Post-Repair Inspection (Recheck)—§ 192.760(g)

Under the NPRM proposal, an operator may typically only consider a leak repair as "complete" if the operator conducts a post-repair inspection and obtains a gas concentration reading of zero percent gas by volume at the leak location. The NPRM required operators to use leak detection equipment that meets the proposed 5-ppm sensitivity standard in § 192.763(a)(1)(ii) when conducting a post-repair inspection. PHMSA uses the terms "post-repair inspection" and "recheck" interchangeably throughout this final rule to refer to the process of confirming that repairs are complete.

PHMSA proposed that an operator must conduct a post-repair inspection between 14 and 30 days after the date of the repair. PHMSA intended the minimum 14-day interval before the post-repair inspection to help ensure that the inspection accurately reflects the condition of the repair, since repairs may have a zero percent reading at the moment of repair, but gas may leak over time from an incomplete repair, another unknown leak in the immediate vicinity of the repair, or the repair may fail. The 30-day maximum inspection time was intended to align with the monitoring timeline PHMSA proposed for grade 2 leaks in the NPRM. As proposed, if the operator was unable to achieve a zero percent reading, the repair would not be complete. If the post-repair inspection found gas concentration levels or evidence of gas migration indicating that the potential for a grade 1 or grade 2 condition exists, the operator would re-inspect the repair and take immediate and continuous action to eliminate the hazard and complete the repair. If the post-repair inspection detected a gas reading of greater than zero percent gas but did not indicate that a grade 1 or grade 2 condition exists, the operator would remediate the repair and re-inspect the repair within 30 days. The operator would then continue re-inspecting the repair at least once every 30 days until the operator obtained a gas concentration reading of zero percent at the repair site. As proposed, an operator would be required to complete the leak repair within the general repair deadline for a grade 3 leak (24 months from the date of initial detection) or within the repair deadline for a grade 3 leak that was downgraded under proposed § 192.760(g) (§192.760(i) in this final rule).

PHMSA proposed to exempt from the post-repair inspection requirement any grade 3 leak on aboveground pipeline facilities that is eliminated by routine maintenance work, such as adjustment or lubrication of aboveground valves, or tightening packing nuts on valves with seal leaks, since such repair or remediation of these routine types of leaks is expected to be successful, and a post-repair inspection would rarely detect any continued leakage.

Upgrading and Downgrading—§ 192.760 (h) and (i)

In the NPRM, PHMSA proposed to establish requirements for when and how an operator could upgrade a leak to a higher-priority grade or downgrade a leak to a lower-priority grade. Proposed § 192.760(f) (§192.760(h) in this final rule) would require an operator to upgrade a previous-graded leak to a new grade whenever the operator receives information that a higher-priority grade condition exists on that leak. For an upgraded leak, the proposed repair deadline was the earlier of the remaining repair deadline for the original grade, or the repair deadline under the new leak grade measured from the date the operator received the information that a higher-priority grade condition exists, to help ensure that operators would not be able to extend leak repair timelines by exploiting the upgrading process.

PHMSA proposed to allow an operator to downgrade a leak only if the operator had performed a temporary repair or attempted a permanent leak repair but did not obtain a zero percent gas reading during the post-repair inspection under proposed § 192.760(e) (§ 192.760(g) in this final rule). This proposal was intended to prevent an operator from artificially and temporarily removing grade 1 or grade 2 conditions, such as by venting to reduce the gas concentration, without an effort to actually repair the leak. If an operator downgraded a leak, the NPRM proposed that the period for repair would be the remaining time allowed for repair under its new grade measured from the time the leak was first detected, to incentivize timely completion of downgraded repairs and prevent manipulation of repair deadlines through nominal attempts at repair.

Recordkeeping

The NPRM proposed specific recordkeeping requirements for leak detection, investigation, grading, remediation, and repair activity, primarily at § 192.760(i) (§ 192.760(j) in this final rule). PHMSA proposed to require operators to retain records documenting the complete history of investigating and grading each leak, including documentation of grading, monitoring, inspections, upgrades, and downgrades, until 5 years after the date of the final post-repair inspection. The NPRM further proposed to require operators retain records associated with the detection, remediation, and repair of each leak for the life of the pipeline. This proposed permanent recordkeeping requirement applied to both piping and non-piping portions of the pipeline, including the date, location, and description of each leak detection, and the repair and remediation of each leak. If an operator detected a leak during a patrol, survey, inspection, or test, the operator would need to retain the pertinent portion of documentation for that activity pursuant to proposed § 192.760(i) (§192.760(j) in this final rule). This recordkeeping proposal was intended to support the periodic evaluation and improvement of operator ALDPs pursuant to proposed § 192.763(a)(4) and to facilitate regulatory oversight by PHMSA and its State partners.

2. *Summary of Public Comments*

Leak Investigation

In comments submitted after the May 2021 Public Meeting, AGA et.al. provided an example of a leak investigation procedure that included observations that occur prior to pinpointing the leak source and final classification or grading of the leak. The GPTC and some operators commented that some operators promptly repair all leaks, and therefore procedures for grading all leaks are not necessary if operators repair all leaks when found. The City of Adairsville stated that grading all leaks would delay leak repair and risk mitigation and that immediate repairs in lieu of leak grading should be encouraged. The Industry Trades and the NGA similarly requested that PHMSA provide operators with the flexibility to eliminate leaks with "immediate and continuous action" and without grading the leaks first.

An operator asked PHMSA to clarify the intent of the phrase "investigated immediately and continuously" in the proposed § 192.760(a)(3), as the operator stated they use mobile leak detection at night, and the literal interpretation of the phrase might require deployment of leak surveyors in driveways and yards late at night. The TPA and TCC urged PHMSA to remove this phrase, reasoning that it would be impractical for an operator to "immediately and continuously" respond to "any leak, regardless of how minor." As noted in the summary of comments on ALDP procedures in section III.E, several operators requested PHMSA clarify that leak investigation and grading may occur, or must occur, prior to pinpointing the location of the leak under § 192.760.

Post-repair Inspection/Recheck

The PST supported the proposed post-repair inspection requirement but commented that leaks eliminated by routine maintenance activity should not be exempted from the requirement as proposed in the NPRM. An operator supported post-repair leak inspections for below-ground leaks but suggested PHMSA should allow operators to schedule a recheck when soil conditions are appropriate rather than set a narrow, prescriptive window. The New York State Department of Public Service supported the proposed requirements at § 192.760(e) (§192.760(g) in this final rule), stating that the post-repair inspection would enhance public safety and minimize the impact of pipelines on the environment, noting too that leak rechecks are required within 30 days of repair in New York.

Atmos Energy Corporation suggested PHMSA use the phrase "post-repair reevaluation" instead of "post-repair inspection," reasoning it was more descriptive of the actions to be taken. Alternatively, the Industry Trades recommended the term "recheck" to differentiate the requirement from other "inspections" required in part 192.

Multiple operators opposed proposed § 192.760(e) (§192.760(g) in this final rule), reasoning the increase in post-repair inspections would divert resources from repairs without any demonstration of improvement to public safety or environmental protection. Similarly, PPL Corporation commented that leaks do not need to be re-inspected after repair, noting repairs by qualified personnel are not likely to leak again, and repetitive rechecks divert resources from more imperative repair efforts, particularly with the new proposed grading standards.

Multiple individual operators and the Industry Trades opposed the 14-day minimum leak recheck interval, stating that the delay of post-repair checks was only necessary to ensure repair and the elimination of residual gas in cases where leaks permeated the surrounding soil, as zero-percent readings can be made immediately after repairs in most other cases. Specifically, Philadelphia Gas Works commented that "the appropriate timing of a post-repair recheck is dependent on whether a repair can reasonably be confirmed to have eliminated the leak," and that generally only below-ground leaks where gas has permeated the soil require such a waiting period. Washington Gas suggested PHMSA remove the specified timeframes and clarify that below-ground repairs can be assessed through barhole testing based on decades of successful below-ground repairs. Multiple operators and the Industry Trades commented that PHMSA should require operators complete post-repair rechecks between 12 and 72 hours after a leak repair is completed, and that post-repair rechecks should not be required for leaks eliminated through routine maintenance work. These commenters added that re-inspections are needed only for completed repairs with sub-surface gas indicators.

Similarly, the GPTC and several operators commented that the proposed requirement would either require operators keep excavations open for 14 days, which particularly inconveniences the public when leaks are under roadways, or re-excavate the leaks, which incurs costs and carries a risk of damage to the pipeline. The commenters requested PHMSA clarify whether excavated repair sites had to remain open during the 14-day period. Multiple operators and an individual commenter said the 14-day period for post-repair leak inspection would cause resource constraints, inflate operating costs, and redundancy. The commenters suggested it be eliminated and that immediate repair confirmation be permitted through approved methods.

The GPA Midstream Association, et al. opposed the zero-percent threshold for requiring a repair be completed, reasoning it contradicts with the EPA's standard for compressor stations, ignores environmental sources of methane and temporary repairs, and requires operators to repair leaks under the detection threshold. The TPA and the TCC said that the zero-percent standard was contradictory, as operators would continue to make repairs even though leaks would be below the 5-ppm sensitivity standard proposed in § 192.763. The commenters suggested PHMSA revise proposed § 192.760(e) (§192.760(g) in this final rule) to account for this contradiction as well as environmental factors that may prohibit a reading of zero percent, such as swamp bogs.

Several commenters recommended specific exemptions from the proposed post-repair inspection requirements. The Industry Trades commented that leaks from construction activities and third-party excavators should not need post-repair inspection because the extent of damage is obvious. Vermont Gas Systems, Inc. added that leaks eliminated through equipment replacement also should not need post-repair inspection. NiSource Inc. provided recommendations for leak repairs that should be exempted from post-repair rechecks, including leaks eliminated by routine maintenance, grade 3 and aboveground leaks, and when pipelines are abandoned and replaced. The Industry Trades also expressed that offshore transmission and offshore gathering lines should be exempt from post-repair inspection requirements, as it would be challenging for operators to perform underwater post-repair checks. Enstor Gas and an individual commenter suggested PHMSA should only require post-repair inspections for grade 1 and grade 2 leaks. Conversely, the PST recommended PHMSA extend the proposed requirements at § 192.760(e) (§192.760(g) in this final rule) to aboveground facilities and grade 3 leaks repaired via routine maintenance to ensure leaks do not worsen and operators properly perform repairs. Encino Environmental Services expressed support for the proposed provision but suggested PHMSA allow operators to use OGI cameras instead of sensors or sniffers during post-repair inspections.

KOGA suggested that residual gas is most likely due to gas-impregnated soil rather than a failed repair, and therefore, instead of requiring operators re-attempt repairs, PHMSA should instead require operators to continue to monitor and assess the leak to confirm the state of the surrounding soil and the leak itself. The GPTC suggested leaks be considered "repaired" if gas migration has stopped, test hole readings are diminishing, and readings are below the LEL, as the hazard is eliminated.

The Industry Trades proposed PHMSA revise the rule to require operators take the following actions in response to a recheck: (1) If a zero-percent reading is obtained, the leak repair is complete; (2) if the gas concentration is shown to be lower than the previous reading, then the operator must schedule a follow-up within 30 days, repeating monthly until a zero-percent reading is obtained; (3) if the gas concentration reading is greater than the previous reading, the operator must investigate and repair the leak.

Several pipeline operators commented on the costs of the proposed post-repair inspection requirements, stating that the proposed post-repair inspections, especially the 14-day waiting period, will create additional burden that will draw resources away from repairs and other pipeline safety initiatives, such as IM and leak-prone pipe replacement programs. INGAA and the Industry Trades cited rechecks as one of the many sources of emissions and costs that would outweigh the environmental and safety benefits of repairing small-volume grade 3 leaks.

Upgrading and Downgrading

Regarding the proposed restriction against downgrading leaks prior to an attempted repair, multiple operators and the Industry Trades suggested that PHMSA allow operators to downgrade leaks that were initially incorrectly graded by operator personnel. The Industry Trades provided examples of situations where operator personnel were overly conservative with initial grade determinations but follow-up investigations found that the leaks were actually a grade 2 or grade 3 condition. The commenters suggested PHMSA require operators to address these types of errors under the OQ requirements in subpart N of part 192. Washington Gas opposed the proposed downgrading provision because it would require operators to excavate leaks before downgrading was permitted, and suggested, as an alternative, allowing operators to downgrade leaks based on re-surveys that occur at least 24 hours but no later than 48 hours after the initial discovery of the leak.

Atmos Energy Corporation commented that the proposed upgrading and downgrading requirements generally reflected their existing practices, though the commenter noted that leaks are not downgraded and instead each leak is repaired based on its original grade unless the leak is upgraded. Alexander City Gas Department added that the proposed prohibition on downgrading leaks ignored the fact that venting could lessen the severity of a leak.

KOGA noted that PHMSA proposed to prohibit leak downgrading unless a temporary repair had been made but said that temporary repairs would not be allowable for grade 1 leaks as proposed. The commenter suggested PHMSA clarify that temporary repairs would be allowed for grade 1 leaks.

Recordkeeping

Vermont Gas Systems, Inc. supported the application of the proposed recordkeeping requirements to buried gas pipelines but not for aboveground facilities, as their work management system does not include risers and regulators. Atmos Energy Corporation supported the proposed recordkeeping requirements applicable to this provision. KOGA said that the proposed recordkeeping provisions would require operators to create procedure manuals, provide updates, and train staff on the new procedures. Multiple operators and the Industry Trades opposed the proposed record retention requirements, reasoning the requirements are confusing and contradicted other record retention requirements.

The Industry Trades suggested that PHMSA modify the record retention timeframe for transmission and distribution lines to 10 years to better align with DIMP requirements. NAPSR suggested operators maintain investigation and grading records for the life of the pipeline if the repaired pipeline element remains in service. GPA Midstream Association, et al. suggested the recordkeeping requirement be limited to 5 years, the lifetime of a relief device, or the next reconfiguration of a relief device, reasoning that the proposed requirements were unjustified and burdensome. Alexander City Gas Department suggested operators instead be required to retain leak data for one interval "across the board."

NiSource Inc. requested confirmation from PHMSA that the lifetime recordkeeping requirements were prospective and expressed concern that some requirements of the NPRM could be applied retroactively. The commenter suggested PHMSA revise the final rule in a way such that proposed § 192.760(i)(2) (§192.760(j)(2) in this final rule) mirrors existing § 192.709 to prevent inconsistency.

3. GPAC Deliberation Summary

The GPAC was briefed on the NPRM with respect to the proposed leak grading, repair, and response requirements in proposed § 192.760 on November 29, 2023, during the first GPAC meeting for this rulemaking. PHMSA's briefing included a presentation of the proposed regulatory language, including a discussion of its costs and benefits, and an overview of material comments from stakeholders on the proposal. Following the briefing by PHMSA staff, the GPAC provided an opportunity for statements from stakeholders in attendance. Individuals representing distribution operators provided a few comments related to other leak management topics in § 192.760. Regarding post-repair rechecks, industry representatives argued that delayed post-repair rechecks were unnecessary for leaks caused by third-party damage, leaks eliminated by pipe replacement, and leaks eliminated by tightening, lubrication, or adjustment since the extent of the damage and efficacy of repair is immediately apparent. A representative of a gas gathering pipeline trade association commented that a "zero percent" criterion for post-repair rechecks was impracticable and that the threshold should be based on the leak detection equipment detection limit (see discussion in III.D) in order to account for background methane readings and the capability of leak detection equipment.

GPAC members proceeded to discuss the leak management requirements at § 192.760 on December 1, 2023, culminating in recommended revisions to the requirements for leak repair reevaluations (recheck) and weather-related repair of grade 2 leaks following environmental changes. Discussion and votes on these topics focused on scenarios where an immediate reevaluation would be appropriate and where a follow-up reevaluation would be required.

The Committee then discussed, at length, the requirements proposed in the NPRM for an operator to recheck a leak repair after 14 days. Members representing industry, including those with gas transmission, gathering, and distribution assets, expressed concern with the recheck requirement blanket application on all repairs completed on all asset types. The members representing industry felt this was an inefficient use of resources, would result in increased emissions from the responses, and that resources would be better used to complete additional leak repairs.

A government member stated that a recheck is required in their State regulations for grade 1 leaks. A member representing the public supported the rechecks especially for grade 1 and 2 leaks. Another member representing the public provided a summary of a PHMSA-funded research project conducted on a distribution system in the Boston area that found leak repairs had a 20 percent failure rate, with most failing within the first year of the repair. A member representing the public and an industry member expressed support for concentrating on distribution systems, rather than repairs on gas transmission and gathering lines, with both stating that repairs on gas transmission and gathering systems are usually confirmed complete at the time of the repair.

An Industry member, representing a gas transmission and distribution operator, proposed a compromise position for consideration that allowed exceptions in instances where a recheck is unwarranted. Multiple industry members and a member representing the public discussed that, even with proposed exceptions, with the expedited leak survey frequency, the repair would be validated at the next leak survey. The GPAC discussion continued with members requesting and providing clarification for the proposed exceptions. A member representing the government discussed current State requirements for grade 1 leak repairs and that, if a repair is completed by a method other than pipe replacement, the operator would have to wait until the excess gas leached from the soil prior to the recheck. A member representing the public was comfortable with such a State requirement becoming the basis for the Committee recommendation. An additional proposal was provided by the member representing a State, and the two proposals were successfully combined.

The GPAC discussed, at length, the exceptions proposed and provided insight as to why certain repairs completed by pipe replacement, abandonment, or routine maintenance would not require a recheck due to the repair's ability to be confirmed at the time of completion. The Committee noted that, in other instances where a facility was damaged due to excavation damage or on an aboveground facility, the extent of the damage is known for repair. A member representing industry transmission and distribution assets specified that, regarding other instances, if a zero-percent reading is achieved immediately after repair, a recheck would not be necessary given there was no residual methane in the soil. The commenter continued that where a zero-percent gas reading could not be achieved at the time of repair, the soil would need to time to release the methane, and the operator would return to validate the repair in 30 days.

The GPAC then began to discuss the investigation of repairs of leaks following environmental changes contained at proposed §§ 192.723(e) and 192.760(c)(5). PHMSA staff communicated that this would be instances where an environmental condition would alter the gas migration pattern and could increase the severity of a leak to the point where immediate repair would be necessary. Members representing industry and government agencies expressed concern that if a weather event is coming (if advance notice is available), the operator would be preparing for the event and should not be worried about fixing a grade 2 leak. Industry members representing transmission and distribution assets pointed out that, as written, all grade 2 leaks would need to be repaired prior to the event, which is not practical or even physically possible.

These members mentioned that current practice involves a patrol after an event to determine where their facilities may have been damaged, followed up by leak surveys, as appropriate, in those locations.

Multiple members representing the industry felt as though an IM, risk-based approach was the best way to manage repairs prior to an event. A member representing the public agreed that investigating leaks is a logical thing to do after environmental changes and supported prioritizing investigations and repairs based on risk. Multiple members representing both the public and the industry mentioned the confusion between what appear to be duplicative requirements requiring inspection before and after an event, as well as repair before an event. A member representing the government mentioned that weather events are not easy to predict and that this is "situationally-based for the State regulator to work with the operators." Multiple members representing the public and the industry mentioned that PHMSA could leverage the extreme weather events referenced at § 192.613 in these requirements. Additionally, government and industry representatives mentioned the challenge of defining what a weather-related event is, with a member adding that they should defer to the State authority when defining extreme weather. These commenters added that location, personnel safety, and environmental conditions need to be considered when making these decisions. Multiple public and industry representatives provided language to be incorporated into the GPAC's recommendation.

4. GPAC Recommendation

The Committee did not make any recommendations to PHMSA regarding the upgrading, downgrading, and recordkeeping proposals.

The Committee engaged in lengthy discussions regarding post-repair inspections, which the Committee referred to as post-repair "rechecks." While the GPAC did not provide specific recommended changes, they unanimously recommended PHMSA reconsider the scope of the recheck requirements for certain types of leaks, considering the following:

The GPAC recommends PHMSA consider the public safety and environmental implications of the following considerations based on the mandates from Congress, the GPAC discussion, State programs, other provisions from the NPRM, and public comments:

i) exceptions for 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;

ii) exceptions for grade 3 leaks;

iii) exceptions for leaks on aboveground pipeline facilities;

iv) exceptions for repairs for excavation damages;

v) exceptions for remediating leaks through pipeline replacement;

vi) exceptions for remediation where the leaking pipeline is abandoned; and

vii) post-repair rechecks to all subsurface leaks on a gas distribution pipeline that is repaired, other than by the replacement or abandonment of the affected section of pipe, must be conducted after allowing the soil to vent and stabilize but not more than 30 calendar days after the repair, unless a zero percent gas reading was taken at the time the repair was complete.

The Committee unanimously recommended that the NPRM, as published in the Federal Register and as supported by the PRIA and Draft Environmental Assessment, regarding leak grading and repair requirements was technically feasible, reasonable, cost-effective, and practicable if the following changes were made:

- PHMSA consider a risk-based approach for the repair of grade 2 leaks following environmental changes that affect gas migration (e.g., freezing ground, heavy rain, flooding, or other changes).
- PHMSA provide for the consideration of local safety and environmental conditions.

5. PHMSA Response

Leak Investigation

PHMSA appreciates the concerns raised by commenters on the proposed requirement to investigate leaks immediately and continuously until a grading determination has been made. This requirement was intended to address the potential for hazard that exists when a leak has been discovered but the operator has not yet determined the leak grade. Prompt grading helps ensure that an operator addresses the hazards of a grade 1 leak before the leak leads to an incident. However, commenters noted that the phrase "continuous investigation" was unclear. To clarify, PHMSA has revised this final rule to be consistent with the suggestion from the Industry Trades to require operators to investigate each leak or indication of a leak immediately and grade them as a part of an operator's leak investigation procedures. PHMSA still expects operators to determine the grade of leaks as soon as practicable to determine if conditions that are hazardous to public safety are present; however, PHMSA believes removing the phrase "continuous monitoring" will avoid some of the burdens described in public comments, such as requiring operator crews on private property overnight. Regarding the comments concerned about the burden of grading leaks for operators who promptly repair all leaks when found, as described in the discussion of the grade 1 and grade 2 leak criteria in section III.H.4, if an operator uses the "judgment of operating personnel" to rapidly classify leaks as grade 1, further investigation is not required after making a determination based on that criterion.

Similarly, after ruling out a grade 1 leak, an operator may use the "judgement of operating personnel" criterion to grade all remaining leaks as grade 2 without having to first determine if the leak met other grade 2 criteria. An operator is free to promptly repair all leaks when found without further grade determination or otherwise establish a default minimum priority grade as part of their O&M procedures. PHMSA considered the impact that an operator's policy of establishing a minimum priority grade could have on leak performance measures. For example, if an operator promptly repairs all leaks when found, annual report data would indicate that the operator has a large number of grade 1 leaks, making the system appear higher risk despite this proactive behavior. As described in the discussion of reporting in section III.L, PHMSA has revised the annual report form to allow operators to indicate if they use a minimum priority grade as part of their procedures. This permits PHMSA and other users of PHMSA data to correct for operator procedures when comparing LDAR data between operators.

In response to comments opposing the implication that locating the source of a leak must occur before leak grading, PHMSA has revised the requirement to specify that each leak or indication of a leak must be investigated and graded. Adding "or indication of a leak" clarifies that an operator does not necessarily need to pinpoint the source of a leak prior to establishing a leak grade. For example, if an operator detects gas at the outside wall of a building, this leak may be graded without first having to find the source of the leak in accordance with § 192.763.

Post-Repair Inspection (Rechecks)

This final rule retains the proposed general requirement that operators use leak detection equipment after repairing a leak to validate that gas is no longer being released to confirm that the repair was successful, that there are no other undiscovered leaks in the immediate vicinity, and that potential hazards to public safety and the environment have been eliminated. PHMSA refers to this process as a "recheck" in this final rule (instead of the "post-repair inspection" term used in the NPRM) to differentiate the validation of leak repairs from other inspections required by part 192. PHMSA does not use the term "reevaluation," as suggested by some commenters, because of the potential confusion with the process for periodically monitoring grade 2 and grade 3 leaks under § 192.760(e) of this final rule.

PHMSA has narrowed the scope of the post-repair recheck requirement in this final rule to provide exceptions where rechecks are not necessary and to allow operators to immediately perform rechecks without a waiting period where the likelihood of or consequences of a failed or missed repair is expected to be minimal. For example, PHMSA is finalizing the proposed exception for leaks that are eliminated through routine maintenance work, due to the likelihood that these routine leak repairs will be successful. Consistent with the GPAC recommendation and public comments, PHMSA is expanding the proposed exception to apply to any leak eliminated through routine maintenance work, regardless of grading or location, again due to the high probability of successful repair. The impact of this change is likely minimal since a significant portion of leaks that can be eliminated through lubrication, tightening, or adjustment are likely to be small leaks on aboveground facilities covered under the proposed scope. PHMSA is similarly not requiring operators to recheck a leak that is eliminated by replacing the affected pipeline segment or through permanently abandoning the pipeline. Since the leaking pipe segment is no longer operating in either of these situations, a recheck is simply not applicable.

Under this final rule, an operator can perform a recheck with no waiting period after the repair for certain leaks where the likelihood of unknown leaks being present is relatively low, specifically leaks located on an aboveground or submerged pipeline segment, or leaks caused by excavation damage and the extent of the damage is known. For submerged pipelines, it should be immediately visually apparent to an operator if there is still leakage immediately after an attempt at repair. This change eliminates potentially significant costs for performing unnecessary follow up dives to confirm the successful repair of leaks on submerged pipelines, including offshore transmission and gathering lines submerged below the waterline. Similarly, and consistent with the GPAC recommendation, this final rule allows an operator to perform a recheck immediately after repairing any grade 3 leak due to the comparatively low risk associated with such leaks. PHMSA considered providing full exceptions to the post-repair recheck requirement under these circumstances, but after considering the safety and environmental implications of these changes, PHMSA determined that allowing for immediate rechecks (i.e., eliminating the proposed 14-day waiting period) will best address the concerns raised by commenters and members of the Committee by minimizing the costs and burdens on operators (since operator personnel will already be onsite performing the leak repair), while still protecting against the hazards from failed repairs, including undiscovered leaks. Eliminating the required waiting period for these rechecks will also avoid any potential environmental and safety impacts that might result from pulling operator personnel away from other tasks to perform rechecks later.

This final rule retains the requirement that operators to wait for at least 14 days, and up to 30 days, before performing a recheck to validate a successful repair or until the operator has otherwise determined that the soil has vented and stabilized. This waiting period is intended to allow time for gas to vent through soil and stabilize so that operators will not receive false-positive indications of leaks, which is especially critical for high-volume grade 1 and grade 2 leaks that may have emitted significant quantities of gas into the surrounding soil. However, as an alternative, PHMSA will also allow an operator to perform a recheck on a shorter timeline if the operator determines that the soil has adequately vented and stabilized after the attempted repair. Allowing the soil conditions to stabilize before an operator performs the post-repair recheck helps ensure that the recheck accurately reflects the completeness of the repair. PHMSA recognizes the concerns regarding the prescriptive wait period, and therefore, while a 14 day-wait period is similar to existing standards in the State of New York and is the default timeline in this final rule, an operator may perform a recheck earlier (or later) based upon a determination by the operator that the soil has adequately vented and stabilized. This change helps ensure rechecks are performed accurately while addressing concerns about a prescriptive time limit. If an operator performs a recheck of a repair after determining that the residual gas has dissipated and the operator has returned the soil or environment to its original state (i.e., backfilled, paved, etc.), that will satisfy this requirement to confirm the completeness of the repair by providing a timeframe for any potential remaining leakage to present itself. An operator must retain documentation supporting this determination in accordance with the recordkeeping requirements in § 192.760(j).

Under this final rule, a successful post-repair recheck need only show a gas concentration reading of less than 1 percent LEL (500 ppm for natural gas) instead of the proposed zero percent gas reading. For buried pipelines, this can include barhole testing at the repair location. This is consistent with the ALDP standards for handheld leak detection equipment for aboveground and indoor facilities in § 192.763(b) as described in section III.D. PHMSA has not adopted the 5-ppm standard for handheld leak detection equipment used for leak surveys of buried pipelines for this purpose. Unlike for leak surveys of possible leaks, the source of the potential leakage is already known and likely exposed in these scenarios, reducing the need for operators to use more sensitive equipment for this particular application. Additionally, operators commonly use CGIs for repair inspections, and a 1 percent LEL reading is significantly above background methane concentration, addressing a concern from commenters. Finally, this policy is consistent with the definition of a fugitive emissions source when using EPA Method 21 to comply with EPA emissions monitoring standards, which is similarly based on direct measurement at the source of a known leak. PHMSA is providing additional flexibility for grade 2 and grade 3 leaks where gas is slow to dissipate by allowing operators to continue conducting rechecks in 30-day (or shorter) increments, so long as the measured gas concentration is lower each time than it was during the preceding recheck, until is the operator obtains a gas concentration reading of less than 1 percent LEL and the repair is complete. This provision should help ensure that operators do not re-attempt repairs unnecessarily where repairs have been successful but where gas is lingering due to slow venting of the soil. However, if the gas concentration detected during a subsequent recheck is higher than or equal to the measurement from a prior recheck, indicating that gas is not dissipating faster than it is being replaced via leakage, the operator is required to investigate the repair to determine the source of potential leakage and, if applicable, correct the repair or begin managing any newly discovered leaks in accordance with § 192.760. The operator must upgrade the leak under § 192.760(h) if, at any time during a subsequent recheck, the operator detects a gas concentration or other information indicating that a higher-priority grade exists. Operators must complete repair prior to the repair timeline applicable to the leak in § 192.760.

This final rule does not adopt the suggestion to consider the initial attempt at repair the date that the repair has been completed, rather than when an operator performs the final recheck. First, such a change would raise the question of what PHMSA expects when an operator completes repair of a leak but subsequent rechecks find the repair was unsuccessful, potentially after the repair deadline. A definitive repair timeline is necessary for the repair requirement to be meaningful, including to allow for effective enforcement by PHMSA and its state partners. Additionally, while a likely outcome of an unsuccessful recheck is the presence of an additional leak, it is also likely that the additional leak was present during the initial survey; operators can reduce the risk of undiscovered leaks with improvements to leak survey procedures and careful investigation of leaks. Grade 1 and grade 2 leaks may be downgraded after an attempt at permanent repair, effectively granting additional time for repair. Finally, as described in section III.I, this final rule adopts extended repair timelines and additional options for delaying repair compared to the NPRM, in part to address these circumstances and other situations where more timely repairs may not be practicable.

Based on analysis in the final RIA, adopting the recheck requirement in § 192.760(g) as specified above does not significantly affect the costs and benefits of the final rule. In the RIA, PHMSA estimates the incremental cost of a post-repair recheck, beyond the cost of the repair, at $109 per leak. This is based on 2 hours of a technician's time, i.e., one hour to mobilize/demobilize and travel to the location, and one hour to conduct the measurements needed to confirm the repair and document the activity.

Reevaluation of Leaks Following Environmental Changes (§ 192.723(e))

PHMSA appreciates the public comments noting a potential for discrepancies between the proposed requirement at § 192.723(e) to investigate leaks after environmental changes that could affect gas migration and the proposed requirement to immediately repair grade 2 leaks in § 192.760(c)(5). PHMSA agrees that this potential for discrepancies is most appropriately addressed under the leak grading and repair requirements in § 192.760 rather than under the requirements for gas distribution leak surveys in § 192.723.

In this final rule, PHMSA has merged these requirements into a requirement at § 192.760(f) to reevaluate known, below-ground grade 2 and grade 3 leaks when the operator becomes aware of changes to the environment near the existing leak, including but not limited to freezing ground, heavy rain, flooding, or new pavement, that could affect gas migration and could allow gas to migrate to the outside wall of a building. PHMSA concurs with comments that treating all leaks as grade 1 leaks when such conditions occur unnecessarily increases costs if, upon investigation, the leak has been found to remain lower risk to public and environmental safety. The reevaluation of known leaks addresses the intent of these requirements, which was to identify leaks that are found to have become more hazardous due to changes in the environment around the existing leak. If an operator finds a more hazardous condition exists during such an investigation, the operator would be required to reevaluate the grade determination, and if necessary, upgrade the leak as intended by this revision according to § 192.760(h). On the other hand, if an operator performs a reevaluation and the leak remains at its original grade (i.e., a grade 2 or grade 3 leak), then the leak does not need to be repaired to a grade 1 standard and on a grade 1 timeframe. This final rule addresses commenter concerns about the scope of this inspection requirement by specifying that operators must inspect leaks that could cause gas to migrate into nearby buildings and adopts clarifying language suggested by the Industry Trades specifying that an operator may conduct such a reevaluation as part of its general procedures for evaluating weather-related impacts.

Additionally, PHMSA agrees with concerns raised by public comments that requiring operators to reevaluate leaks when changes to the operating environment that could affect gas migration "are anticipated" rather than "have occurred" is both difficult to implement and potentially limited in value. Therefore, this final rule clarifies that operators must only perform this reevaluation after a more hazardous condition is found to exist near the existing leak. This change also more clearly differentiates the requirement for operators to investigate known leaks after environmental changes that could affect gas migration from the requirement to perform a leak survey to search for potential new leaks after extreme weather events with the potential to cause damage to a gas distribution pipeline facility as described in section III.A.

Upgrading and Downgrading

PHMSA is generally adopting the leak upgrading and downgrading provisions as proposed in the NPRM, which were largely supported by operators and the Committee, with a few clarifications to the downgrading provisions to address issues raised by commenters.

First, this final rule clarifies PHMSA's proposal that an operator may downgrade a leak after a temporary repair, including a temporary repair of a grade 1 leak. Leaks downgraded in this manner are ineligible for the repair exception of certain grade 3 leaks to help ensure a timeline for permanent remediation of temporary repairs and to avoid incentivizing ineffective repair procedures. This is described in greater detail in section III.I. The proposed requirement to condition downgrading on an attempt at repair, rather than simply venting the soil, was intentionally designed to help ensure that operators take steps to eliminate the underlying source of potential hazards to public safety and the environment on an appropriate timeline. PHMSA is aware that venting surrounding soil or opening underground structures can reduce gas concentration, but this does not address the source of the hazard. Therefore, venting was intentionally excluded from the conditions for downgrading a leak. PHMSA did not propose, and is not finalizing in this rulemaking, downgrading based on subsequent surveys without an attempt at repair for the same reason.

If an operator initially graded a leak incorrectly based on the information available at the time of discovery or leak grading, that operator will be permitted to downgrade a leak under this final rule, even if no repair was attempted. This provision only applies in those narrow circumstances where operator personnel erred in initially grading the leak based on the operators' procedures and information available at the time the grade was made. However, PHMSA is not requiring operators to address these types of errors under subpart N, as suggested by some commenters, because conservatism on the part of operating personnel on the scene does not necessarily indicate a systematic issue with following procedures or the qualification of operator personnel. Nevertheless, an operator should consider whether grading errors represent a deeper issue with knowing and following the operator's procedures when the operator evaluates its individual and OQ programs under subpart N, especially when leaks are incorrectly classified at a lower-priority grade.

Recordkeeping

This final rule largely finalizes, with a few clarifications, the proposed requirements for operators to maintain for 5 years records of leak grading and related tasks, such as reevaluations, rechecks, and upgrading and downgrading, and for operators to retain for the life of the pipeline records of the leak repair or remediation, including date, location, and description. These records are necessary to demonstrate compliance during an inspection or investigation, particularly for grade 3 leaks with a multi-year (or indefinite) repair timeline. This information is especially important for pipe and facilities subject to IM requirements, and therefore this final rule requires lengthier retention requirements for this subset of information. Information about repairs is important information for operators to have sufficient information to know about and address safety risks. In the worst-case scenario, inadequate or incorrect information can cause an operator to miss critical threats to pipeline integrity issues, fail to use assessment methods to detect those issues, and fail to take appropriate preventative and mitigative measures, potentially resulting in an incident.

PHMSA is clarifying in this final rule that operators must maintain for 5 years records documenting the grade determination, reevaluations, rechecks, upgrades, and downgrades made in accordance with § 192.760. PHMSA will not exclude records for reevaluations and rechecks, as requested by some commenters, because these records are necessary for an operator to demonstrate compliance with the requirements of this section. PHMSA also disagrees with comments suggesting that the previously existing DIMP recordkeeping requirements address and are duplicative to the per-leak grading and investigation records of this requirement. Section 192.1011 is a general requirement for operators to maintain for 10 years records demonstrating compliance with DIMP. While information on leak grading, either on an individual basis or as higher-level summary statistics, is likely to be used to inform system knowledge, threat identification, and performance measures under DIMP, subpart P itself does not prescribe the per-leak detailed recordkeeping that is necessary for operators to be able to demonstrate compliance with § 192.760. However, if an operator does use records generated under this section to demonstrate compliance with DIMP, then they must retain those records for 10 years as specified under § 192.1011.

PHMSA has also clarified in this final rule that the records of repairs of leaks on non-pipe components on gas transmission and regulated gas gathering lines may be retained for a shorter period if such an interval is permitted under § 192.709. Thus, operators to whom § 192.709 applies may retain records of the date, location, and description of leak repairs (other than repairs to pipe) for 5 years after the repair or until the next patrol, survey, inspection, or test is completed, whichever is longer. However, operators must retain records of all leak repairs on distribution lines and records of repairs to line pipe on gas transmission or regulated gas gathering lines, including repairs of pipe-to-pipe connections, for the life of the pipeline in accordance with §§ 192.760 and 192.709(a) as applicable. This change avoids conflicting recordkeeping requirements for transmission lines between §§ 192.760 and 192.709 and addresses public comments concerning contradictory or burdensome record retention requirements. Section 192.709 requires permanent retention of pipe information necessary for IM while ensuring sufficient retention requirements to demonstrate compliance with repair requirements for non-pipe components during periodic inspections.

Finally, PHMSA has also clarified in this final rule that the new recordkeeping requirements apply to activities performed in accordance with § 192.760 and therefore do not apply retroactively.

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

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to add a new § 192.769 to specify that only individuals qualified under subpart N of part 192 may conduct leak survey, investigation, grading, and repair activities required by the NPRM, clarifying that such activities are covered tasks under subpart N. PHMSA also proposed to require that such qualified personnel must possess training, experience, and knowledge in these tasks, including documented work history or training associated with these tasks. The proposed § 192.769 applied to gas transmission, distribution, offshore gathering, and Type A regulated onshore gathering pipelines. PHMSA also requested comments on whether, within a final rule in this proceeding, it would be appropriate to apply the proposed OQ requirements in § 192.769 to Type B and Type C regulated onshore gas gathering lines or UNGSFs, none of which have been previously required to comply with subpart N.

2. Summary of Public Comments

NAPSR and multiple operators supported the provisions. The Alexander City Gas Department commented that well-trained employees are beneficial to the "integrity of the department" and are worth the cost of additional training. The New York State Department of Public Service expressed support for the proposed provisions, observing that New York State already requires personnel to meet PHMSA's proposed training and OQ requirements.

The Industry Trades, GPA Midstream, et al., and multiple operators claimed that § 192.769 is duplicative and unnecessary because leak survey, grading, and repair activities already constitute covered tasks under § 192.801(b). GPA Midstream, et al. added that subpart N already provides a "comprehensive framework" for personnel qualification and that there was no reason to add leak-specific requirements to the OQ program. However, other comments, such as Producers Midstream and Air Liquide Large Industries U.S. L.P., took the position that leak investigation and grading are not covered tasks and stated that requiring leak investigation and grading to be performed by qualified personnel would be highly burdensome on operators. Air Liquide Large Industries U.S. L.P. suggested PHMSA provide an 18-month development period for the OQ portion of the rule. Multiple industry representatives commented that proposed § 192.769 should not have lumped leak survey, investigation, grading, and repair all together, since leak detection personnel might only participate in some, but not all, of these activities. As drafted, proposed § 192.769 implied that these personnel must be trained on each of the listed tasks to perform any of them.

The Industry Trades and multiple industry representatives expressed concern that proposed § 192.769 would eliminate the ability for unqualified individuals to perform these activities under the observation of qualified individuals, as currently permitted for covered tasks under subpart N. The Industry Trades also argued that training documentation is not always required under subpart N and observed that personnel training, and documentation thereof, is currently only required as part of an OQ program "as appropriate" to ensure that individuals performing covered tasks have the necessary knowledge and skills to perform the tasks in a manner that ensures the safe operation of pipeline facilities.[363] Commenters suggested that the proposed § 192.769 could lead to confusion as to whether the covered tasks listed in that proposed section would be held to a different standard than other covered tasks under subpart N. National Grid noted a new training requirement would have significant implications and high estimated costs. The Industry Trades suggested that it would take months for operators to develop and implement revisions to OQ procedures to include new training requirements.

[363] 49 CFR § 192.803(h).

Several commenters provided suggested changes to the proposed regulatory language of § 192.769. The TPA and the TCC suggested PHMSA remove the proposed requirement for personnel to have "experience" in leak grading, reasoning that only a limited number of personnel would have actual experience in the area at the time the rule is finalized. The Industry Trades recommended that the term "leak investigation" be distinguished from the term "leak survey" or deleted from the proposed amendments altogether.

The NPRM requested comment on whether PHMSA should apply proposed § 192.769 regarding clarifications to OQ requirements to UNGSFs. The Industry Trades and multiple operators said § 192.769 or subpart N should not be extended to cover UNGSFs, stating that UNGSF OQ requirements are already addressed sufficiently in API Recommended Practices 1170 and 1171 (currently incorporated into part 192 by reference), which are properly tailored to UNGSFs.

3. GPAC Deliberation Summary

GPAC discussion of NPRM proposals relative to OQ and other miscellaneous topics occurred on March 27, 2024. PHMSA's presentation on the topics began with a summary of the current regulations on OQ, followed by proposed regulatory language and its supporting reasoning, and an overview of received comments on the proposals in this area. PHMSA noted that several commenters were concerned that the proposal would require workers to be qualified for work that they did not perform and that the proposal would also prohibit unqualified individuals from conducting work under the observation of qualified individuals. PHMSA explained that these two concerns were not consistent with PHMSA's intent and that it would clarify those items in the final rule. The GPAC then provided opportunities for stakeholders present at the meeting to present their feedback. Among the handful of stakeholders who provided feedback were operators, representatives of large transmission pipeline operators, the gas gathering industry and publicly owned gas distribution utility trade associations. Commenters referenced their written comments and highlighted member concerns regarding the additional OQ requirements at the proposed § 192.769. One commenter, a State safety representative, noted that gas gathering operators of Type B and Type C pipelines are not subject to the OQ requirements. The commenter continued that operators of Type B and Type C gas gathering pipelines should be held to the same requirements as Type A gas gathering pipelines and transmission pipelines and be required to use qualified people for leak surveys and repairs.

GPAC members then discussed PHMSA's proposed regulatory language. One GPAC member representing industry operators, including those with significant gas transmission, gathering or distribution assets, felt that the language at the proposed § 192.769 seemingly referred to subpart N as the governing structure for OQ, which was consistent with his understanding of the preexisting regulations on this topic. The member also mentioned the comment regarding qualification requirements for individuals who did not perform the covered tasks; the member stated that individuals would still only be required to be qualified only for the tasks they performed. PHMSA affirmed this stance. A public member was supportive of the State safety representative's comment on OQ requirements for Type B and Type C gas gathering pipelines.

4. GPAC Recommendation

The GPAC did not provide a specific recommendation relative to § 192.769.

5. PHMSA Response

PHMSA appreciates commenters' explanations of why proposed § 192.769 could introduce confusion into the existing subpart N OQ requirements. PHMSA did not intend to create new requirements for the qualification of personnel performing leak survey, investigation, grading, or repair tasks. Nor did PHMSA intend to remove the ability of operators to use unqualified personnel under the supervision of qualified personnel in accordance § 192.805(c). Rather, PHMSA simply intended to clarify that the listed activities (leak survey, investigation, grading, and repair) constitute "covered tasks" under subpart N since they are specified in the O&M requirements in part 192. PHMSA agrees with the large number of commenters that § 192.769 would be duplicative with the existing subpart N. In addition, PHMSA did not receive comments specifying the benefits of applying to OQ requirements in § 192.769 to UNGSFs. Therefore, PHMSA is not finalizing proposed § 192.769 in this rulemaking. PHMSA clarifies that the status quo is being maintained with respect to the requirements of subpart N, including its applicability (i.e., subpart N is not applicable to Type B and Type C gathering lines nor UNGSF).

Based on PHMSA's decision to not incorporate the proposed § 192.769, PHMSA did not conduct an analysis of this specific provision in the final RIA.

L. Reporting—§§ 191.3, 191.9, 191.11, 191.17, 191.19, 191.23, and 191.29

1. Summary of PHMSA's Proposal

To collect more data on pipeline leaks and other emissions, the NPRM proposed new and revised reporting requirements. The most significant of these proposals would create a large-volume gas release (LVGR) report to supplement existing incident reporting requirements. As is the case for incident reports, PHMSA proposed that this requirement would apply to any gas pipeline facility covered under part 191, including jurisdictional storage and part 193 LNG facilities. Additionally, PHMSA proposed to revise the annual report forms for gas transmission; offshore gathering; Types A, B, and C gathering; and distribution operators to include each of (1) the estimated aggregate emissions from all leaks existing on a given system within the calendar year by grade (including emissions within the calendar year from leaks discovered in prior years), (2) other methane emissions by source category, and (3) the number of leaks detected and repaired by grade.

At § 191.19, PHMSA proposed to require a new report for intentional and unintentional releases from a gas pipeline facility with a volume of 1 MMCF or greater, excluding certain events that had been reported as incidents under §§ 191.9 or 191.15. As proposed, operators would be required to submit a report within 30 days from the date that a release of 1 MMCF or more was detected, or 30 days from the date that a previously detected release became reportable. If the time that a leak started was unknown, an operator would base its calculation on the estimated release volume from the date of the most recent leak survey. PHMSA proposed that events that were reported as LVGRs would be exempted from § 191.23 SRC reporting requirements.

PHMSA explained that operators of all gas pipeline facilities would still be required to submit incident reports if unintentional releases reported under the proposed new LVGR requirement also met incident reporting criteria. Per the proposal, operators who already submitted an incident report would not need to file a LVGR report under § 191.19 for the same event so long as the release volume in the incident report was within 10 percent of the total release volume when the release ended.

PHMSA proposed to clarify what it considers as "property damage" for the purpose of determining whether a release is reportable as an incident pursuant to §§ 191.9 or 191.15. Specifically, PHMSA proposed that the definition of "incident" at § 191.3 would be revised to exclude costs associated with obtaining permits or the removal or replacement of infrastructure undamaged by the event (e.g., pavement needed for access and repair activity) in connection with an event from the calculation of estimated property damage. Under the proposal, operators would still report these costs as incident consequences on the applicable incident report forms; however, those costs would not be included when calculating whether a given release exceeded the property damage threshold to be reportable as an incident.

PHMSA also proposed changes to the gas distribution, transmission, offshore gathering, and regulated onshore gas gathering annual reports required by §§ 191.11 and 191.17, consistent with other changes proposed in the NPRM regarding leak grading and repair on those facilities and to improve information collection on estimated total emissions from pipeline facilities.

PHMSA specifically proposed to revise the annual report forms for operators of gas distribution, offshore gathering, regulated onshore gathering, and transmission pipeline facilities to collect data on each of the following: the number of leaks detected and repaired by grade (see § 192.760), the estimated aggregate emissions from all existing leaks (whether detected in the reporting year or not) by grade, and estimated emissions from other sources by source categories. Since the NPRM did not provide leak grading requirements for LNG facilities, operators of those facilities would be required, per the proposal, to report data on the number of methane leaks detected and repaired during the annual reporting period pursuant to § 193.2624, the number of unrepaired leaks at the end of the annual reporting period, and the estimated fugitive methane emissions from all methane leaks identified pursuant to § 193.2624 (each by GHGI source category).

The proposed source categories for emissions reporting generally mirrored the categories in the GHGI and are summarized in section II.C.2. of the NPRM. Per the proposal, in developing aggregate emissions estimates, PHMSA recommended that operators employ direct measurement or top-down methodologies along the lines of those discussed in section III.C.2. of the NPRM.

In the NPRM, PHMSA also proposed to require operators to submit geospatial data about offshore gas gathering and Type A, Type B, and Type C gathering pipelines to the National Pipeline Mapping System (NPMS). The NPMS is a geographic information system (GIS) that contains the locations and related attribute data for a variety of pipeline facilities. The proposed requirement to submit data to the NPMS would provide valuable information to improve emergency response and would help facilitate gathering pipeline operators' efforts in developing and maintaining adequate maps and records of their systems. See section III.P. for the proposed NPMS requirements for regulated gas gathering pipelines.

2. Summary of Public Comments

Definition of Large-Volume Gas Release

Throughout the public comment process, PHMSA received feedback on the definition of a large-volume gas release. GPA Midstream et al. suggested that PHMSA should clarify that a reportable large-volume "release" of gas does not include gas that is burned through flaring or consumed as fuel. The MD Attorney General et al. supported PHMSA's proposal to establish a reporting requirement for both intentional and unintentional large-volume releases that is separate from the definition of an "incident."

Southern Company Gas opposed the flow-rate standard. The commenter instead supported a total volume criterion set at 2 MMCF, arguing that environmental impacts to the atmosphere are tied to the volume of methane released, not the flow rate of that release. The commenter noted that leaks caused by excavation damage on every main and service operating at 60 or 300 PSIG would be reportable with a 100 kg/hr flow rate. Further, they noted that all releases from relief valves and regulator stations would be reportable if a 100 kg/hr flow rate was adopted.

RMI and Carbon Mapper further recommended that PHMSA align its LVGR reporting requirements with the EPA's proposed revisions to its Greenhouse Gas Program in 40 CFR part 98, subpart W, to the extent possible. This comment recommended that PHMSA adopt the 100 kg/hr instantaneous flow-rate criterion proposed by the EPA and use the same rate standards and default leak duration assumptions for calculating the total release volume of LVGR reporting that the EPA uses, including the EPA's rules for persistence[364] when the date the leak started is not known. Williams Companies, Inc. implied that PHMSA should use the 3 MMCF threshold for LVGRs as well.

After the March 2024 GPAC meeting, multiple commenters submitted additional comments regarding the proposed reporting threshold for the LVGR report. Multiple commenters, including the Industry Trades, Southern Company Gas, Williams Companies, Inc., and Northeast Gas Association, asked for PHMSA to remove the proposed flow-rate standard of 100 kg/hr. These comments argued that while this standard may be appropriate for uncontrolled releases and leaks of unknown duration, imposing this criterion on all releases could require operators to report controlled releases of high flow rate but short duration that emit relatively small total volumes of gas. Williams Companies, Inc.'s April 2024 comment noted that, while "[t]he 100kg/hr threshold is important for leak grading and repair timelines and ensuring that once an operator is aware of a high leak rate it quickly addresses the leak," a short-duration release measured instantaneously at 100 kg/hr could result in very small total releases that have relatively small environmental impact, and therefore flow rate alone should not trigger the need for an operator to file a LVGR report.

Large-Volume Gas Release Report

[364] Persistence refers to the EPA requirement for helping operators determine leak duration should there be an absence of data.

The GPTC, KOGA, and other commenters mistakenly claimed that the proposed form and instructions were not accessible for review. PHMSA uploaded all proposed new and modified forms and associated instructions to the public docket for review before May 25, 2023.[365]

NAPSR supported the new 49 CFR 192.19 as proposed. Several commenters, such as Young Evangelicals for Climate Action, supported the new requirements in the interest of greater transparency and accountability. Multiple commenters, including the PST, the Joint Environmental comment, Rep. Rick Larsen et al., State Rep. David Michel, and Citizens for a Healthy Community, generally supported proposed 49 CFR 192.19 but recommended that PHMSA align its standard with the EPA's proposed amendment to its 40 CFR part 98, subpart W, Greenhouse Gas Reporting Program, which has proposed a new "other large release event" reporting category with two separate reporting thresholds of 100 kg/hr and 250 mt CO_2 equivalent (approximately equal to 500,000 SCF of natural gas). Another commenter, Encino Environmental Services, supported a 1 MMCF threshold but believed that PHMSA should add another criterion based on flow rate to ensure that all significant releases of gas are appropriately captured. The MD Attorney General et al. urged PHMSA to consider a lower threshold than 1 MMCF and noted that the State of New York has a standard of 10,000 SCF to trigger reporting requirements regarding planned and unplanned blowdowns. The Joint Environmental comment argued that PHMSA should modify its proposal to set a threshold of 0.5 MMCF for reporting

[365] These documents were posted to the public docket at PHMSA-2021-0039-0018 and PHMSA-2021-0039-0024. Specifically, the proposed changes to the forms were published on May 25, 2023, and the associated instructions were published in the docket on May 13, 2023.

LVGRs. Xcel Energy supported the proposed requirement but requested that the flared volume be reported separately, since the carbon equivalent values would differ. Similarly, GPA Midstream and Williams Companies, Inc. requested that PHMSA clarify that gas that is flared or otherwise combusted as fuel should not be counted towards LVGRs. NiSource Inc. and Kinder Morgan, Inc. also suggested that PHMSA should remove as duplicative the proposed requirement for operators to submit an LVGR report for releases that exceed 10 percent of a previously reported incident, since supplemental incident reports required under §§ 192.9(b) and 192.15(d) will already capture this information.

Kinder Morgan, Inc. requested that PHMSA provide an exemption for releases equal to or greater than 3 MMCF, to avoid duplication with incident reporting requirements. Multiple commenters, including Williams Companies, Inc., INGAA, the Industry Trades, Philadelphia Gas Works, and Kinder Morgan, Inc. asked PHMSA to provide a way for operators to rescind a LVGR report if a single release event that is first reported as a large-volume gas release later develops into an incident by exceeding 3 MMCF.

KOGA opposed the LVGR report, believing it was unnecessary and would impose a heavy administrative burden, noting that PHMSA could collect the requested data through existing annual report and incident forms. The commenter estimated the approximate annual cost of compliance for these reports at an additional $50,000 in administrative costs and $25,000 in field labor.[366] INGAA urged PHMSA to reevaluate the estimated paperwork burdens, as it argued that PHMSA's estimate is not clear and at times inconsistent. INGAA suggests that the

[366] The commenter did not state what their current costs are to comply with existing forms.

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 PHMSA would take longer than the 4 hours estimated in the NPRM. The GPTC believed that this report would dilute the designation of an incident and asked PHMSA to consider the potential conflicts with existing State and Federal reporting requirements. Some commenters suggested that if an operator has already reported a particular gas release event to the EPA or a State agency acting pursuant to the EPA reporting requirements, then the operator should not have to submit a LVGR report to PHMSA. Multiple commenters, including GPA Midstream et al., INGAA, and Kinder Morgan, Inc., and April 2024 Industry Trades, emphasized that PHMSA should be careful not to create duplicative reporting requirements with other agencies.

The Joint Environmental comment argued that operators should be required to use 1 day after the last date the leak location was surveyed as an estimated start date for the leak as this would motivate operators to strive for greater leak survey frequency. On the other hand, multiple commenters, including Kinder Morgan Inc., the Industry Trades, Philadelphia Gas Works, INGAA, and Williams Companies, Inc., requested that PHMSA allow operators to calculate the volume of gas lost from a leak based on the date of discovery, where the initiation of the release is unknown, rather than based on the date of the last leak survey. Commenters argued that PHMSA's proposal to use the date of the last leak survey could significantly over-estimate emissions, and that using the date of discovery would result in more accurate estimates, as "it is far more likely that a leak began when it was first detected than at the time of the last survey date."[367] Additionally, INGAA pointed out that PHMSA did not include this information in the proposed instructions for the LVGR Report. Williams Companies, Inc. argued that in some cases (such as releases on Type R gathering lines), operators may not have ever performed a leakage survey on a given segment and would have no basis for estimating total emissions under PHMSA's proposal. The commenter requested PHMSA revise the final rule to account for this situation. Furthermore, Williams Companies, Inc. argued, even if there was a recent leak survey for such pipes, assuming the leak started at the conclusion of that last survey is not a reasonable assumption. They continued that, if the start of a leak was unknown, then PHMSA should let the operator base its leak calculations on the date the leak was first discovered or the date of the first indication of the leak.

Multiple commenters, including the Industry Trades, INGAA, Philadelphia Gas Works, and Williams Companies, Inc. requested that PHMSA permit operators to use a tabular reporting process in order to streamline reporting and allow operators to populate and revise data more efficiently. Similarly, in their April 2024 comments, Industry Trades, Northeast Gas, and Williams Companies, Inc. asked for the ability to submit LVGRs in a batch reporting structure to further reduce the reporting burden on operators and improve the efficiency of quarterly reporting (as recommended by the GPAC).

The Joint Environmental comment supported quarterly reporting for the LVGR report but asked PHMSA to consider updating these requirements in the future such that operators will eventually be required to report such releases at the time of the event. The commenter also asked

[367] (PHMSA 2021-0039-26287) August 17, 2023. pp. 5

that PHMSA require operators provide narrative descriptions of how they calculated the volume of released gas in order to promote accountability and foster industry-wide familiarity with best practices for quantifying released gas.

Reporting Granular Leak Data

Many individual commenters participated in a letter-writing campaign that asked PHMSA to expand reporting requirements for pipeline operators. The commenters argued that more data and transparency from operators would help mitigate current harms from pipelines as well as better inform future agency actions. Thermo Fisher Scientific supported requiring operators to submit more granular leak data as part of annual reports, arguing that this would lead to improved detection and attention of leaks and leak-prone infrastructure; and therefore, would generally result in greater reductions in methane emissions and improved public and environmental health. The Joint Environmental comment urged PHMSA to require operators to report leak location, leak grade, leak flow rate (if known), date of leak identification, date of repair, and the last date the leak was surveyed prior to the date of leak identification, explaining that this data would enhance accountability and transparency surrounding leak management practice of operators. Additionally, the Joint Environmental comment argued that the collection of these dates (date of leak identification, date of repair, and the last date the leak was surveyed prior to the date of leak identification) would allow an operator to calculate the estimated total methane emissions associated with the leak. However, the Industry Trades stated that operators reporting more granular data on leaks would be "wholly impractical" based on personnel skills, resources, and technologies currently deployed by operators in pinpointing and repairing leaks.

Air Liquide Large Industries U.S. L.P. suggested that PHMSA should consider whether State-level regulatory agencies would require differing data elements, also suggesting that the labor hours required to comply as well as the costs may be substantial.

Boston University School of Public Health and Physicians/Scientists and Engineers for Healthy Energy asked PHMSA to require the reporting of natural gas composition, including specific VOC content, explaining that many VOCs are hazardous air pollutants identified by the EPA as being known or suspected to cause cancer or other serious health effects. The commenter argued that data on VOC content is necessary to fully evaluate and understand the air quality, public health, and environmental consequences of pipeline leaks.

Annual Report

Several commenters, including the Philadelphia Gas Works and INGAA, asked for PHMSA to change the March 15 annual reporting deadline for the Gas Transmission Annual Report form to June 15, in light of increased information required to be included with each annual report. The Industry Trades, Southwest Gas, and the Great Basin Gas Transmission Company supported the aforementioned request and similarly asked PHMSA to change the deadline for the Gas Distribution, LNG, and UNGSF Annual Report forms.[368] These commenters noted that hazardous liquid operators have until that date to submit their annual reports, and aligning these dates would be beneficial for entities that operate both gas and hazardous liquid pipelines. Williams Companies Inc. claimed that the proposed changes to the

[368] The Differentiated Gas Coordinating Council supported switching the "gas reporting deadline" be extended from March to June, but did not specify, which natural gas forms (i.e., Transmission or Distribution or Type R) should be affected. (PHMSA-2021-0039-26353). August 17, 2023. p. 5

annual report would add strain to their workforce. In their April 2024 comments, the Industry Trades and the NGA also asked for the Type R annual report (OMB Control No. 2137-0522) to be submitted on June 15.[369]

NAPSR requested that PHMSA explain and clarify how operators should estimate annual emissions to better ensure the accuracy of operator estimates. Similarly, the Industry Trades stated that its member organizations have varying levels of ability to estimate total emissions, and that most operators are not able to deploy comprehensive and advanced top-down methodologies to estimate total emissions, nor to perform direct measurement of individual leaks. Therefore, the Industry Trades recommended that operators be given an option for estimating emissions in both the aggregate and for individual leaks. Additionally, the commenter requested that PHMSA align its options for reporting emissions with the methodology proposed in the EPA's Greenhouse Gas Reporting Program SNPRM, which proposed to permit operators to make direct measurements of equipment leaks and other emissions sources and report those measurements in lieu of using default GHGI emissions factors.[370] Eversource Energy asked PHMSA to reconsider collecting the estimated aggregate emissions from pipelines as it does not provide additional safety to consumers.

[369] Northeast Gas Association's August 2023 comment did not opine on this issue. Their April 2024 comment also supported adjusting the date to June 15th for the natural gas distribution, transmission, and LNG annual reports. (PHMSA-2024-0005-0378). April 29, 2024. p. 18

[370] See EPA SNPRM, 88 FR 50282 (Aug. 1, 2023), subsequently finalized in 89 FR 42062 (May 14, 2024).

Multiple commenters, including the Industry Trades, INGAA, and Philadelphia Gas Works, stated that PHMSA should update the burden hours associated with completing an annual report and contended that PHMSA's estimates of 21.5 hours for the burden was incorrect.

The PST and the Joint Environmental comment supported the proposed changes to the annual report forms and requested that they be expanded to cover Type R gathering lines.

KOGA noted that the proposed modifications to Form F 7100.2-1, specifically for the data on leaks detected, leaks by grade (repaired or unrepaired), and aggregate emissions, would require operators to comply with additional reporting and tracking requirements. The Industry Trades suggested that PHMSA should remove the distinction from leaks discovered and leaks repaired on the proposed annual reports because leak cause can be unknown until repaired (and may never be known if a segment is replaced before a leak is repaired), and therefore the number of leaks discovered and repaired will not line up. Multiple commenters, including INGAA, Philadelphia Gas Works, and the Industry Trades, asked PHMSA to consider adding back to the annual report instructions statements suggesting that releases that can be eliminated by routine maintenance (such as lubrication, tightening, or adjustment) need not be reported as leaks. Commenters suggested that releases of gas that can be eliminated by routine maintenance should not be considered "leaks." The Industry Trades expressed concern with part C1 on the Gas Distribution Annual Report as it might introduce confusion. They suggested that PHMSA clarify that operators need only report leaks that occurred on piping jurisdictional to the operator, since public reporting is likely to include leaks on customer-owned piping and false positive reports.

In the Joint Environmental comments, the commenters requested that PHMSA require operators to include in their annual reports a list of all grade 3 leaks operators are monitoring (rather than repairing) as well as a list of all notifications operators are making to PHMSA in order to extend leak repair deadlines under §§ 192.760(d) and 192.760(h).

Safety-Related Condition

The GPTC asked PHMSA to clarify the intent of the proposed addition of the phrase "to public safety" in § 191.23 expressing concern that this addition appears to narrow the scope of an SRC. NAPSR expressed general support for SRC reports in § 191.23 and did not provide further detail.

Williams Companies, Inc. requested clarification as to whether an operator would need to report a leak that also qualifies as an "incident" on both a 30-day report and in the list of leaks on an operator's annual report, and similarly whether a leak initially reported on an operators' annual report that later develops into an SRC or LVGR is expected to be reported twice.

Third-Party Reporting

In the NPRM, PHMSA solicited comments on how to best incorporate third parties into the leak detection and reporting regulations and whether PHMSA should revise § 192.605 to address operators' procedures for responding to third-party reports of gas releases or otherwise incorporate elements from the EPA's Super Emitter Program. Multiple commenters, including Physicians for Social Responsibility Pennsylvania, Clean Air Council, and Pennsylvania State Senator Katie Muth, suggested that PHMSA establish a structure to receive third-party air monitoring data similar to the EPA's Super Emitter Program, noting that additional air quality monitoring around pipelines and related storage facilities will allow operators to more quickly find and fix leaks. Pennsylvania State Senator Katie Muth suggested PHMSA make that real-time data available on a public-facing website. Carbon Mapper and RMI suggested that PHMSA coordinate with other agencies to align third-party standards and reporting pathways for high-emission events. Specifically, the commenter noted that harnessing remote sensing technologies and coordination among key Federal agencies would allow for opportunities to quickly identify and mitigate large methane release events.

Bridger Photonics, Inc. recommended that gas sensing technologies be qualified based on third-party testing according to standardized testing protocols, reasoning that this would increase transparency and uphold high scientific standards.

Atmos Energy Corporation did not support PHMSA revising § 192.605 to require procedure manuals to address operators' procedures for responding to third-party reports of gas releases, as operators are already required by PHMSA to have public awareness programs that include providing information to the public about how to notify the operator of suspected gas releases. This commenter and Sanders Resources stated there are existing methods for third parties to communicate with PHMSA about potential concerns regarding compliance, and that these notifications need not be codified in regulation. The Industry Trades opposed PHMSA revising § 192.605 out of concern that this would create distractions from operators' primary objective of ensuring public safety, both due to the lack of familiarity of third-party reporters with the system or operational knowledge necessary to reliably identify gas releases from operators' jurisdictional facilities and potentially even due to malicious operational disruption by bad actors.

Incident Threshold

In the NPRM, PHMSA solicited comment on whether alternative reporting thresholds for incidents or LVGRs, including thresholds below 1 MMCF, would be advantageous. Williams Companies, Inc. urged PHMSA to retain the existing 3 MMCF threshold for incidents, as the proposed 1 MMCF threshold for LVGR reports could be triggered frequently by blowdowns on large-diameter, Class 1, Class 2, or Class 3 pipelines operating at 700 psig or greater due to the amount of gas likely to be located between valves due to valve spacing requirements. Conversely, RMI and Carbon Mapper requested that PHMSA lower the incident reporting threshold from 3 MMCF to 1 MMCF.

The April 2024 comments from the Industry Trades, the NGA, and Williams Companies, Inc. requested that PHMSA revise § 191.3 to eliminate the unintentional 3 MMCF gas loss criterion, since these events would be reported through the LVGR report. These commenters suggested that this revision would ultimately result in incident reports being focused on safety-related events and separate environmentally significant releases are separated from safety-related events.

The PST stated that the property damage criterion for determining whether a release event should be reported as an incident should continue to include the cost of permits and removal or replacement of infrastructure undamaged by an event. The commenter recommended rescinding a 2021 amendment that adjusted the previous $50,000 threshold for property damage criterion in the definition of an incident for inflation. The commenter continued by stating that this revised criterion, \$139,700 in 2023,[371] is significantly higher than the hazardous liquid pipeline accident definition, which remains at \$50,000 in accordance with § 195.50(e).

The New York State Department of Public Service expressed concern that the proposed modifications to the definition of "incident" could result in similar leaks triggering incident reporting in some localities but not in others due to the differences in the cost of operating in those localities. This commenter was also concerned with comparing "incidents" reported before the adoption of these changes with those reported after these changes are made.

General

The MD Attorney General et al. supported the proposed reporting requirements by stating that PHMSA has the broad authority to make such changes, and changes to reporting will provide important information at a more accurate level, which will enhance their understanding of public health and environmental risks.

The PST requested that annual reports be made available on the PHSMA website without a Freedom of Information Act (FOIA) request. Federal Hermes Limited requested that PHMSA establish a transparent, credible, and empirically based methane emissions reporting framework to improve the accuracy and credibility of reported emissions data to enable investors and customers to clearly differentiate between leaders and laggards.

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[371] The property damage criteria are updated annually; beginning July 1, 2024, it is \$145,400. See "Gas Property Damage Reporting Threshold—Part 191 Appendix A" (Feb. 15, 2024). phmsa.dot.gov/incident-reporting/2024-gas-property-damage-reporting-threshold-inflation-adjustment.

An individual commenter, Kirk Frost, requested a complete pipeline inventory and audit status repository that tracks every foot of pipelines as well as updates from pipeline owners and PHMSA field agents.

Comments addressing LNG facilities are discussed in section III.G.

3. GPAC Deliberation Summary

GPAC discussion of existing §§ 191.11, 191.17 and NPRM proposals for reporting pursuant to §§ 191.3, 191.23, and 191.19 occurred on March 26, 2024. It began with PHMSA's summary presentation of the proposed regulatory language and its supporting reasoning, including a discussion of its cost and benefits, and an overview of material comments from stakeholders on the proposal. The GPAC then provided an opportunity for stakeholders present at the meeting to comment, where representatives of gas transmission and distribution pipeline operators, individuals representing environmental non-profits, and a public interest environmental lawyer shared feedback. Multiple industry commenters referenced their written comments and emphasized their desire for a quarterly reporting deadline for the LVGR report; the ability to submit the LVGR report in a tabular format; a later annual report deadline; and avoiding duplicative reporting with existing incident reports and EPA 40 CFR part 98, subpart W, requirements. Individuals representing environmental non-profits expressed support for requiring gathering pipeline mileage be reported to NPMS,[372] the collection of more granular data on the annual report, requiring that operators report the number of leaks detected and repaired by grade, reporting requirements for Type R gathering lines, harmonizing the LVGR

[372] PHMSA notes that discussion of gas gathering and NPMS is located in section III. P.

definition with EPA requirements, and reporting on hydrogen blending with distribution systems. Furthermore, there was a request that PHMSA collect data on grade 3 leak repair extensions and grade 3 leaks being monitored rather than repaired.

Subsequently, the Committee discussed the NPRM with respect to reporting at length. Committee members representing the industry and the government supported the differentiation of safety incidents from environmental incidents, as the response time is different. A member representing the public highlighted the importance of reporting to increase access to information about the country's energy infrastructure, which will allow both the public and regulators to understand equity impacts and make better decisions. A Committee member representing the gas transmission industry raised changing the annual report deadline from March to June. The majority of the discussion was focused on settling on an appropriate LVGR threshold and whether the standard should be based on total volume or flow rate.

A Committee member representing the public supported a LVGR threshold of 100 kg/hr because an operator would be able to easily calculate the volume released. In consideration of the previously discussed the leak grade criteria and what constitutes a notable event, a Committee member representing the public expressed support for a threshold of 500,000 SCF, aligning with an EPA proposal that has since been finalized. A member representing industry contemplated the difference between a 100 kg/hr leak for 30 minutes versus a 100 kg/hr leak for a year. There was desire from both members representing the public and industry for alignment with EPA's reporting thresholds, and it is during this line of conversation that a discussion of a total-volume criterion with an associated time delineation arose. A public member raised an openness to a longer time frame (i.e., quarterly reporting deadline) for the LVGR report as a compromise since the reported data is so valuable. There was support from Committee members representing both the industry and the public on a flow-rate-over-time criterion, specifically 100 kg/hr for a week. A Committee member representing the public noted that a leak of 0.5 MMCF over 4 days would be equivalent to a 100 kg/hour leak. A public member raised having a nearer-term notification that would precede the more detailed quarterly LVGR report in order to increase access to information. A Committee member representing industry raised placing a time delineation on the flow-rate standard; however, a Committee member representing the public noted it was not necessary since the two options had an "or" between them, so operators would only need to satisfy one of the options. Subsequently the public member noted that the flow rate standard of 100 kg/hr did not need a time delineation, as operators will report the duration of the leak.

4. GPAC Recommendation

The GPAC's recommendations on reporting reflect a unanimous consensus among Committee members regarding how PHMSA could adjust its proposal to navigate the different considerations described above. The Committee stated that the NPRM, as published in the Federal Register and supported by the preliminary RIA and Draft Environmental Assessment, was technically feasible, reasonable, cost-effective, and practicable with regards to LVGR reporting if the following changes were made:

- PHMSA adopt criteria consistent with the EPA's standards for 40 CFR part 98, subpart W reporting requirements.

    - In particular, the Committee recommended that PHMSA revise the total volume reporting criterion from 1 MMCF to 500,000 SCF within 4 days, or adopt a 100 kg/hr flow-rate criterion
- Establish a reporting timeline of quarterly.

During the November 2023 GPAC meeting, the GPAC recommended to push certain topics to the reporting portion of the discussion, which was eventually held during the March 2024 Committee meeting. The deferred topics included:

- In the context of blowdown mitigation, the reporting of blowdowns excepted from mitigation requirements due to significant impacts from outages and significant rate shocks.
- Reporting for transmission patrols in accordance with § 192.705.

Ultimately, the Committee did not vote or make recommendations on these deferred topics during the March 2024 Committee meeting during their review of the reporting requirements of the NPRM. However, PHMSA carefully reviewed the transcript of the Committee's discussions of these topics when developing this final rule.

Much of the discussion centered around comprehending a flow-rate versus a total-volume criterion; the Committee members representing industry and the public wanted the large-volume gas threshold to be consistent with EPA's final 40 CFR part 98, subpart W, rule. Woven throughout the conversation was an expressed desire for any and all reporting to be done efficiently and general support for its accuracy and consistency. Ultimately, individual Committee members' requests to have a nearer-term notification in advance of the quarterly

LVGR report and to adjust the gas transmission annual report deadline were not included in the GPAC's voting language.

5. PHMSA Response

Definition of Large-Volume Gas Release

In this final rule, PHMSA adopts the Committee-recommended LVGR threshold of 500,000 cubic feet of gas or greater released within a period of 96 hours. However, this final rule does not adopt the Committee recommendation of a separate LVGR flow-rate threshold of 100 kg/hr or greater. PHMSA received several public comments after the March 2024 GPAC meeting that advised against adopting the Committee-recommended flow-rate standard. These commenters observed that a release of 100 kg/hr sustained over a period of 96 hours, such as through a leak or other uncontrolled release, would emit roughly 500,000 cubic feet of gas, and therefore a sustained release of 100 kg/hr would already be captured by the other criteria for LVGR reporting. In contrast, a short-duration release of 100 kg/hr that was not sustained for 96 hours or more, such as through a controlled blowdown, would release a relatively small volume of gas despite a high instantaneous release rate over a short duration. As PHMSA stated in the NPRM, the purpose of this new LVGR reporting requirement was to capture better information on large-volume releases (not releases of high flow rate but relatively short duration) and the attendant public safety and environmental risks of those releases.[373] In particular, PHMSA sought to address the information gap between unintentional and intentional large-volume releases that had previously existed under part 191 reporting requirements, as the public safety and

[373] 88 FR 31890, at 31945. (May 18, 2023).

environmental risks that result do not depend on operator intent. PHMSA also noted that an LVGR reporting requirement supports Congress's direction in section 114 of the PIPES Act of 2020 for operators to update their inspection and maintenance procedures to provide for the minimization of releases of gas from their pipeline facilities. Adopting a purely flow rate-based reporting requirement, on the other hand, could burden operators with reporting routine, controlled events that do not actually emit large volumes of gas: for example, a relief device on a high-pressure line operating as intended to briefly relieve pressure could be reportable under a 100 kg/hr criterion. Uncontrolled leaks exceeding 100 kg/hr present significant public safety risks and, as grade 1 leaks, will require prompt remedial action, and annual reporting, from operators, in accordance with this final rule.

The Committee-recommended requirement that PHMSA is finalizing in this rulemaking limits the reportable large-volume releases to those that emit 500,000 cubic feet of gas or more over a period of 96 hours, avoiding concerns with PHMSA's original proposal that had no defined duration. Without a defined duration, operators would likely be required to report many relatively small leaks that persist on their systems over months or years. Commenters pointed out that information on aggregate emissions will already be captured and reported to PHMSA with the proposed changes to operator annual reports. A defined measurement duration for LVGRs also addresses comments concerned that assuming the release initiated following the most recent leak survey, if the time the release began was unknown, would lead to operators overreporting small releases. As finalized in this rulemaking, for the purposes of determining whether a release is reportable, an operator is not required to project emissions beyond 4 days. However, when reporting the total emissions from an LVGR, operators should consider the time of the most recent leak survey and other available information when estimating the total emissions from the release. The final LVGR threshold volume may also be easier for operators to implement than a purely flow rate-based threshold, as operators can measure or estimate the release using different types of detection equipment.   PHMSA will not be adopting commenters' suggestions that PHMSA use a higher total volume-based threshold, such as 2 MMCF for the same reasons that PHMSA did not, consistent with parallel EPA reporting requirements, adopt a total volume threshold for the LVGR. Furthermore, this standard would not be a stringent enough standard to achieve PHMSA's goals of the large-volume gas release report. Specifically, knowledge of smaller releases and the circumstances surrounding them are essential to PHMSA carrying out its mandate to ensure public safety and to protect the environment. A higher volume-based threshold would result in these smaller releases not being reported Finally, these recommendations are inconsistent with the GPAC recommendations for a volume-based threshold range from 0.5 MMCF to 1 MMCF over 4 days.

PHMSA's final reporting threshold is not consistent with EPA's final 40 CFR part 98, subpart W, reporting requirements for "other large release events" in the GHGRP, as the EPA adopted a purely flow rate-based reporting requirement and ultimately did not finalize its proposal to require reporting of releases based on volume.[374] However, as EPA states in its final rule, its goal was to ensure that its GHGRP program captures emission events that are not fully accounted for using existing methods in 40 CFR part 98, subpart W, while still being

[374] 89 FR 42062, preamble discussion on other large release events begins on page 42078. (May 14, 2024).

straightforward for operators to implement. Thus, EPA's final rule only required operators to comply with a flow-rate based reporting threshold, and EPA determined that its proposed total volume-based threshold would not have captured meaningfully more emissions events. PHMSA is similarly finalizing a single reporting threshold in this final rule, which will be easier for operators to implement than two separate thresholds, and as discussed above, a 100 kg/hr flow rate threshold would not have captured meaningfully more LVGRs than will already be reported under the requirements finalized herein. In response to a concern from Southern Company Gas, this final rule ultimately adopts a total-volume criterion (albeit over a limited duration) rather than a flow-rate standard.

In this final rule, PHMSA is clarifying in § 191.3 that gas that is intentionally combusted via flaring or as fuel should be excluded when considering if a release is reportable as an LVGR, since gas combusted intentionally in a flare is not released to the atmosphere as such. While PHMSA acknowledges concerns raised by stakeholders concerning the impacts of flares, gas combusted intentionally in a flare contributes less to the public safety and environmental risks motivating PHMSA's reporting requirements compared with gas released directly to the atmosphere. However, gas that is not combusted remains reportable, and operators should consider the efficiency of their flares when determining whether a release that is flared is reportable as an LVGR. Additionally, for events that are reportable, PHMSA requires operators to report the volume of gas that is combusted in a flare. As explained on the LVGR report instructions, operators are instructed to report the estimated volume of combusted gas separately from the volume of gas released intentionally or unintentionally. Operators should again consider the efficiency of flares when reporting the estimated volume of gas released or consumed by fire.

Large-Volume Gas Release Report

This final rule implements the Committee's recommendation to establish a quarterly timeline for submittal of LVGR reports, which responds to queries requesting changing the deadline.

PHMSA also plans to enable the submittal of individual LVGR reports and the submittal of multiple reports in a batch or tabular format. PHMSA expects that these changes will reduce the reporting burden on operators with respect to time and money.

PHMSA considered whether to exempt events reported to EPA from the large-volume gas release report, but ultimately declined to adopt that approach. The two agencies have different aims in their data collection efforts. EPA's Greenhouse Gas Reporting Program aims to improve its estimates of aggregate, nationwide greenhouse gas emissions, whereas PHMSA's reporting goals are to better understand and help operators mitigate and prevent specific releases of gas that present safety and environmental risks. In keeping with these goals, PHMSA's LVGR report provides more granular information than the EPA's requirements, such as requesting the cause of the release and location on the pipe facility. If a release is from blowdown, venting, or purging, operators must report all methods used to mitigate the release.

As previously mentioned, the LVGR criterion includes a total volume of gas over a specific duration. In response to concerns regarding whether a flare volume is expected to be reported separately, PHMSA has clarified in the instructions for the LVGR report that operators should not report the volume of intentionally combusted natural gas. PHMSA agrees with public commenters that, if a given release of gas continues after an operator has submitted an incident report, the operator must later submit a supplemental incident report with updated final release volume estimates once the release ends, in accordance with §§ 191.9(b) or 191.15(d). Therefore, PHMSA has clarified in this final rule that no LVGR report will be required if an incident report has already been submitted for the same release, since the final release volume will already be reported to PHMSA.

Similarly, PHMSA did not intend for operators to submit both an LVGR report and an incident report for an unintentional release equal to or greater than 3 MMCF. Each incident report form includes comprehensive information concerning unintentional releases that meet the definition of an incident, including all of the information on the LVGR report form for unintentional releases. Therefore, submitting both a LVGR report and an incident report is not necessary. If an operator detects an unintentional release of this magnitude, the operator should only submit an incident report. However, should an unintentional release initially trigger only the LVGR reporting requirement but eventually trigger the incident reporting requirement after the operator has submitted the LVGR report, the operator must still submit an incident report. The instructions for the proposed LVGR report allowed operators to rescind or retract the report if the event did not meet the criteria for an LVGR as defined in § 191.3. For clarity, and to reduce double counting reportable events, PHMSA has updated the final form instructions to add that, should an LVGR event develop into an incident as defined in § 191.3, the operator is allowed to rescind their LVGR report.

In response to comments from KOGA suggesting PHMSA could incorporate the data submitted on the LVGR report into the existing annual report and incident forms, these forms have distinct purposes, and it would be untenable to implement the commenter's suggestion to leverage the existing annual report and incident forms. While incident reports provide valuable information on major emissions events with critical safety consequences, existing incident reporting criteria and the exclusion of intentional releases from reporting requirements means the current reporting scheme does not capture data on many significant emissions events, which the LVGR report collects. In response to the GPTC's concern with existing data collection efforts by State-level agencies, PHMSA works to reduce duplication at this level but understands from a feasibility perspective that there are limitations in these efforts due to the wide array of policies and data collection efforts. The Paperwork Reduction Act calls upon PHMSA to ensure that its information collection activities are not duplicative with other Federal agencies.

The issue raised by commenters regarding calculating the volume of gas loss from a leak from the date of discovery versus the date of the last leak survey is rendered moot given the Committee recommended the LVGR criterion is based on a period of 96 hours.

In response to comments regarding how PHMSA estimated the number of LVGR reports that would be submitted, PHMSA has updated the final RIA for this rulemaking to clearly explain how it arrived at its estimated annual number of LVGR reports (which is now based on the new criterion of 500,000 SCF or more released over 96 hours).

Part D of the LVGR report calls for operators to describe the release, including the facts, circumstances, and the conditions that may have contributed directly or indirectly to causing the release. Operators may use this section to clarify or explain unusual conditions and any estimated data. PHMSA expects that operators will leverage their existing procedures for calculating total release volume for incident reporting purposes when developing new procedures to comply with the new LVGR reporting requirement.

The NPRM proposed an exception from SRC reporting for events that were reportable as LVGRs, since the proposed 30-day reporting deadline would help ensure that any SRCs would be promptly reported to PHMSA. However, the quarterly reporting structure adopted in this final rule would not get this vital and time-sensitive safety information to PHMSA quickly enough, and PHMSA has therefore removed the proposed exception from this final rule. Should an LVGR be associated with an SRC, an operator would be required to submit an SRC report within the timeframe laid out in § 191.25 in addition to the quarterly reporting deadline of LVGRs. SRC reports and LVGR reports request different data elements and serve unique purposes; therefore, PHMSA retains both reports in this final rule. Specifically, SRCs are less-detailed than a LVGR report. Operators must report the description of the condition, including the circumstances leading to its discovery, any significant effects of the condition on safety, and the name of the commodity transported or stored. Additionally, the operator must include the corrective actions taken (including reduction of pressure or shutdown) before the report is submitted and action planned follow-up or future corrective action, including the anticipated schedule for starting and concluding such action.

Reporting Granular Leak Data

PHMSA appreciates the many comments in response to its solicitation of public input on the potential utility of collecting more granular leak data from operators. However, in this final rule, PHMSA has decided not to require operators to report more granular leak data in the NPRM, as finalizing the new LVGR report and other proposed updates to annual reports will help ensure that operators are not overburdened by new reporting requirements while improving the agency's understanding of leaks and other releases that present risks to safety and the environment.

In response to the comment regarding existing data collection efforts by State-level regulatory agencies, the Paperwork Reduction Act calls upon PHMSA to ensure that its information collection activities are not unduly burdensome or duplicative with other Federal agencies. As such, PHMSA is statutorily required to reduce the compliance burden on operators associated with collecting and reporting data at a Federal level. Due to the patchwork of policies and data collection efforts at the State level, PHMSA works to reduce duplication at this level but understands from a feasibility perspective that there are limitations in these efforts.

PHMSA also appreciates comments recommending that operators be required to report the composition of gas releases, including VOC content, and PHMSA may consider future changes to reporting requirements to address the increased safety risks from gas releases that contain VOCs.

Annual Report

In this final rule, PHMSA has changed the deadline for operators to submit the Natural and Other Gas Transmission and Gathering Pipeline Systems Annual Report (OMB Control No.

2137-0522) to June 15 for all transmission and gathering line operators, other than Type R gathering line operators. Additionally, PHMSA changed the deadline for operators to submit the Gas Distribution Annual Report (OMB Control No. 2137-0629) from March 15 to May 15. PHMSA recognizes that the annual report forms, particularly Gas Transmission and Gas Gathering annual report forms, have become more complicated over time, including through new requirements introduced with this final rule. Providing operators with additional time to submit these reports will make it easier for them to prepare accurate annual report data submissions. PHMSA is finalizing staggered deadlines in this rulemaking for different reports because the Gas Distribution Annual Report form is not as complicated as the Natural and Other Transmission and Gas Pipeline Systems Annual Report (6 pages versus 25 pages, respectively), and therefore, it should not take as much time for operators to complete. Furthermore, staggering the deadlines for the Natural and Other Transmission and Gas Pipeline Systems Annual Report and Gas Distribution Annual Report allows the agency to provide better technical support to operators. PHMSA has declined to alter the deadline for the Type R Annual Report (OMB Control No. 2137-0522), which remains March 15, as this form is short and less complicated than the other forms, and PHMSA is not making any changes to the content of this form. Similarly, the LNG Annual Report (OMB Control No. 2137-0522) will retain its existing deadline of March 15, as this is also a relatively simple form in comparison to the other annual report forms.

To reduce duplicative reporting for total emissions reported under the EPA GHGRP, PHMSA has decided to strike the applicable parts[375] of PHMSA's annual report forms for gas distribution, gas gathering, and gas transmission pipelines. PHMSA is deferring to the EPA for these reporting requirements and has updated PHMSA's annual report forms to request operators that submit data to the EPA's GHGRP to provide their complete GHGRP ID number to PHMSA. This data field will allow PHMSA to match PHMSA's operator IDs and the EPA's identifying numbers to obtain data. Unlike the LVGR report, the changes PHMSA proposed to the annual report in the NPRM were data already being collected by the EPA. The incident report form, in tandem with the new LVGR report, will give PHMSA a better understanding of emissions from leaking pipelines. This amendment addresses comments that the proposed emissions reporting requirement was duplicative of EPA requirements, and that the expectations regarding the methodology for reporting such emissions was unclear in the proposal.

In response to comments regarding incorrect burden hour estimates at the time of the publication of the NPRM in May 2023, the final RIA addresses this, and PHMSA refers readers to that document for that discussion.

In response to comments requesting expanded reporting for Type R gathering lines, PHMSA did not propose enhanced annual reporting requirements for Type R gathering pipelines because those facilities are not subject to the leak grading and repair requirements at § 192.760;

[375] For the Gas Distribution Annual Report (OMB Control No. 2137-0529), proposed part F, Estimated Emissions During Calendar Year, was struck. For the Natural and Other Gas Transmission and Gathering Pipeline Systems (OMB Control No. 2137-0522), the proposed part U, Estimated Emissions was struck.

therefore PHMSA is not applying enhanced reporting requirements for Type R gathering pipelines in this final rule.

In response to comments regarding the distinction between leaks discovered and leaks repaired, PHMSA understands an operator may not have determined the cause of the leak immediately at the time a leak is discovered. PHMSA has revised the Gas Distribution and Natural and Other Transmission and Gathering Piping Systems Annual Report forms so that operators only need to report leak cause information for leaks eliminated or repaired. Furthermore, PHMSA has also clarified the instructions to include leaks scheduled for replacement. Despite public comments, PHMSA has retained the proposed clarification in Part M1 on the Natural and Other Gas Transmission and Gathering Piping Systems Annual Report instructions. Specifically, this final rule adopts the proposed revision to the annual report form instructions to eliminate exceptions for reporting releases eliminated by routine maintenance, such as lubrication, tightening, or adjustment. Regardless of the method to fix a leak employed by an operator, a leak has released gas to the atmosphere, potentially endangering people, property, and the environment. Therefore, collecting information on such leaks is necessary for PHMSA and other stakeholders to have a complete picture of the impacts of leaks and to evaluate the performance of the leak detection program requirements adopted in this final rule. PHMSA has also updated the instructions to part C1 of the Gas Distribution Annual Report to clarify that operators should only report leaks that occur on their pipeline facilities (and not, for example, on customer-owned piping).

PHMSA will also require that natural gas pipeline operators submit as part of their annual reports the number of leaks existing on their systems with deferred timelines for repair and elimination. Specifically, they must submit the number of legacy leaks pending reevaluation under § 192.760(a)(3) and the number of leaks with subject to delayed or excepted repair requirements under §§ 192.760(c)(3) and 192.760(d)(2). This information will help PHMSA track the total quantity of leaks excepted from repair requirements or subject to delayed repair requirements to better understand the impact of these provisions on the effectiveness of operators' LDAR programs. PHMSA appreciates the interest from commenters in making publicly available notifications received from operators under § 192.18 (or summaries thereof) and may consider implementing such a system in the future.

Safety-Related Condition

PHMSA's proposal to add the phrase "to public safety" to the definition of a "safety-related condition" in § 191.23 was not intended to narrow the scope of an SRC but was intended to clarify the existing interpretation of imminent hazards. Based on public comment, therefore, PHMSA is withdrawing its proposal to amend the definition of an SRC in this final rule and will retain the language as it existed prior to the NPRM. For a discussion of "leak or hazardous leak," please refer to section III.R.

In response to a comment asking whether an operator must report a leak that qualifies as an incident both on an incident report and in its list of leaks on an annual report, PHMSA clarifies that operators must include leaks from incidents in the count of leaks on their annual report. This will help ensure that PHMSA is promptly alerted of the incident and that PHMSA also receives a full picture of the leaks on the operator's system each year. PHMSA has updated the annual report instructions for the Gas Distribution Annual Report form to clarify that reportable incidents should not be reported in the count of leaks and leak repairs on an operator's annual report. To clarify, a leak that develops into an LVGR and requires an LVGR report will be included in an operator's leak count on the annual report form. For a leak that began as an LVGR and then developed into an incident, an operator would submit an incident report, and would not need to submit an LVGR report or include the leak on an operator's annual report. An SRC may cause a leak in the future but is not always leak-related.

Third-Party Reporting

While operators may engage third parties as part of their efforts to comply with the requirements being finalized within this rulemaking (for example, by contracting with vendors of technologies such as those discussed in section II.D.4 of the NPRM), PHMSA did not propose in the NPRM any formal role for third parties in the detection or reporting of leaks or intentional emissions. PHMSA therefore declines to adopt third-party notification requirements in this final rule to consider potential mechanisms for doing so and to allow for additional opportunities for technical evaluation and public feedback. In the future, PHMSA may consider incorporating elements from the EPA's Super Emitter Program, coordinating with other agencies to align third-party certification standards and reporting pathways for high-emission events, and using third-party testing for leak detection equipment qualification. Sections 192.605 and 192.615 as they existed prior to this rulemaking include limited requirements for responding to information from third parties, notably responding promptly to reports of gas odor inside of or near buildings.

PHMSA has existing public awareness programs. Specifically, requirements in §§ 192.605(b)(11) and 192.615(a)(3) that existed prior to this rulemaking expect operators to promptly respond to odor calls inside or near a building. However, PHMSA's expectation is that operators fix leaks beyond responding to odor calls. While odor calls are one of the ways operators become aware of and address leaks, PHMSA and Congress sought to expand leak survey and repair requirements to increase the number of ways operators become aware of and address leaks. Pipe replacement is not addressed by public awareness campaigns.

Incident Threshold

In this final rule, PHMSA is retaining the 3 MMCF threshold for unintentional releases that must be reported as incidents. As discussed above, PHMSA is finalizing a LVGR reporting requirement that will help ensure more large releases are reported to PHMSA, addressing many commenters' concerns about the existing incident reporting requirement. Unintentional releases that exceed 3 MMCF raise greater concerns for public safety and environmental risks, and thus operators will continue to report these incidents to PHMSA on a faster timeline than for the LVGR reports.

PHMSA is also finalizing its proposed amendment to exclude costs associated with the replacement of pavement or other infrastructure that is incidental to repairs from the calculation of property damage sufficient to trigger an incident report. Updating the definition of an incident in this way is directly responsive to NAPSR Resolution 2021-01, "A Resolution Seeking a Modification of PHMSA's Instructions for Incident Reporting for Gas Distribution, Gas

Transmission, and Gas Gathering Systems,"[376] in which NAPSR specifically recommended that PHMSA exclude from the property damage calculation costs such as permitting and restoration costs. Excluding these costs will help ensure that routine maintenance will not be inflated to "incident" status by unique local requirements that result in incidental costs, helping PHMSA to focus on true incidents that may endanger people and the environment. PHMSA is clarifying in this final rule that operators should continue to report these costs as consequences of any reportable incident; however, they should not be included in the calculation of property damage for determining whether a release is reportable as an incident.

PHMSA appreciates the concerns raised by the New York State Department of Public Service about the impact of changes to the incident definition on trend analysis. To account for inflation and past revisions to the definition of an incident, PHMSA has, in the past, provided analyses of "significant" incidents on the data portion of the PHMSA website. However, PHMSA expects that it will not be possible to isolate reported property damage associated with restoration of pavement from past incident reports. The change to the calculation of property damage for the purpose of defining an incident will only affect incidents that do not meet any of the other reportable criteria, and it affects only one portion of the calculation of property damage. PHMSA therefore does not expect the impact on the number of reported incidents to be substantial. Effects on the number of incidents that does occur will be limited to relatively minor incidents where the predominate effect is impacts to surface pavement incidental to repair.

General

[376] http://www.napsr.org/resolutions.html.

PHMSA has summarized and discussed the public comments it received on reporting requirements for hydrogen in section III.Q.

PHMSA appreciates comments in support of a more robust emissions reporting frameworks and detailed, publicly available pipeline emissions inventories. However, PHMSA declines to introduce additional reporting requirements beyond those discussed above. PHMSA seeks an appropriate balance between disseminating valuable information to the interested public and the burden this increased data collection places on operators. All annual report data submitted to PHMSA is publicly available on PHMSA's website at phmsa.dot.gov/data-and-statistics/pipeline/pipeline-mileage-and-facilities. Annual report data is reported at the operator level, which allows for more detailed analysis than would be possible using aggregated data. Furthermore, annual report data, enforcement letters, and special permit letters are posted to PHMSA's public webpage. On PHMSA's DataMart website, the public can view general inspection data, including the type of inspection PHMSA performed, inspection status, the date the inspection was initiated, and the date the inspection concluded. The NPMS also provides the public with important information regarding the locations of gas transmission and hazardous liquid pipelines, LNG plants, and breakout tanks.

In the RIA, PHMSA finds that the final rule will impose an annualized cost of $8.9 million in 2023 dollars and the total annual burden hours will be 153,875. Throughout sections 4.1.4, 4.2.3, 4.3.2, and 8.6 of the RIA, the agency clearly laid out the expected costs and recordkeeping or reporting burdens borne by operators due to the updated and new reporting requirements. PHMSA did not consider alternatives with respect to reporting other than the no-action alternative. The costs are justified by closing informational gaps regarding large-volume gas releases and enhancing information regarding leaks and leak management.

M. Minimizing Vented and Other Emissions from Gas Transmission Pipelines and LNG Facilities—§§ 192.9, 192.12, 192.605, 192.770, 193.2503, and 193.2523

1. Summary of PHMSA's Proposal

In light of the significant safety, environmental, and public health consequences from intentional releases of methane and other toxic, flammable, and corrosive gases—many of which are also greenhouse gases—from blowdowns a from PHMSA-jurisdictional gas pipeline facilities, and to facilitate operator implementation of the self-executing mandate in section 114 of the PIPES Act of 2020, PHMSA proposed to incorporate the statutory language of section 114 of the PIPES Act of 2020 within the Federal PSR.[377] Specifically, PHMSA proposed to incorporate explicit requirements for operators to eliminate leaks of all flammable, toxic, or corrosive gases as well as minimize releases of natural gas into the provisions prescribing the content of operating, emergency, and maintenance manuals for regulated gas pipelines and facilities.[378] Additionally, the NPRM proposed that operators of gas transmission, offshore gas gathering, Type A gas gathering, and part 193-regulated LNG facilities would have to adopt specific requirements for minimizing the release of gas during non-emergency blowdowns, LNG tank boil-offs, and other intentional emissions release events. Accordingly, in the NPRM,

[377] PHMSA has, pursuant to section 114 of the PIPES Act of 2020, initiated a study on the best available technology or practices to reduce methane emissions associated with design, construction, operations, and maintenance of pipeline facilities, and will initiate a rulemaking based on the results of that study.

[378] Specifically, this included gas transmission; gas distribution; and Types A, B, and C gas gathering lines; UNGSFs, and LNG facilities regulated under part 193.

PHMSA proposed to amend its regulations pertaining to gas transmission, offshore gas gathering, Type A gas gathering pipelines, and part 193-regulated LNG facilities to provide a menu of proven options that operators could choose from to mitigate natural gas releases during blowdowns, tank boil-offs, and other vented emissions.

First, §§ 192.770(a)(1) and 193.2523(a)(1) included a proposed method for operators to install valves or control fittings to minimize the volume of gas that must be removed from pipeline facility segments. Instead of blowing down a pipeline facility between mainline block valves or compressor stations, the operator could isolate a shorter segment of pipe. Second, the proposal included an option for operators to route vented gas to a flare stack or to other equipment for use as fuel gas. The third and fourth methods proposed in § 192.770(a) included reducing pressure through prescribed methods (inline compression or mobile compression). The third approach in § 193.2523(a) consisted of transferring natural gas or LNG to a storage tank or local pressure vessel. The fifth method proposed under § 192.770(a) is like the fourth method under § 192.770(a), except the operator would not need to compress the transported product in certain circumstances. The NPRM proposed that operators could employ alternative approaches not listed under §§ 192.770(a) or 193.2523(a) to minimize releases provided that the operator could demonstrate that the alternative method could reduce the emissions from the release by at least 50 percent compared with the operator taking no minimization action.

Sections 192.770(c) and 193.2523(c) proposed to require that operators develop documentation of the method or methods used to minimize emissions from their systems. Sections 192.770(b) and 193.2523(b) proposed that operators would not be required to comply with the minimization of vented emissions by using the methods in §§ 192.770(a) or 193.2523(a) during an event that results in the activation of an operator's emergency plan or procedures in §§ 192.615(a)(3) and 193.2509, respectively. For these events operators would be required to document each release conducted without mitigation pursuant to an emergency plan, including the justification for not taking mitigative action per §§ 192.770(c) and 193.2523(c).[379]

2. Summary of Public Comments

Transmission Blowdowns

Multiple commenters, including the PST, NAPSR, State Rep. David Michel, Rep. Rick Larsen, et al., and Encino Environmental Services, supported the proposed requirements aimed at reducing unintentional and intentional releases. Northern Illinois University supported the proposed provisions at § 192.770(a), reasoning that intentional releases of gas increase the amount of gas emissions and therefore should be avoided. Encino Environmental Services reasoned the proposed requirements would help reduce both vented and fugitive emissions while also preserving pipeline integrity and protecting the environment. The TPA and the TCC opposed the proposed requirements for transmission blowdown mitigation, arguing that the proposed regulations were too prescriptive.

The PST noted that while it supported the flexibility PHMSA proposed to offer to operators under this section, it asked PHMSA to set standards to ensure that operators mitigate 50 percent of their emissions using a given technology and require operators to report what

[379] Note that a blowdown that is not mitigated may also be reportable under the proposed large-volume gas release report.

method was used, including a comparison of the emissions between an unmitigated release and the actual release using the selected method. The commenter added that this reporting would increase transparency and without it, operators could manipulate initial calculations of unmitigated releases.

Rep. Rick Larsen et al. supported the proposed minimization of intentional gas releases caused by maintenance, repair, and construction; the proposed requirement for operators to mitigate intentional emissions; and the proposal for operators to publicly report their efforts to mitigate intentional emissions.

Energy Transfer LP suggested PHMSA should not include a provision for operators to control emissions during a blowdown in the final rule until it completes its congressionally required report of the best available technologies or practices. The commenter reasoned that Congress singled out blowdowns explicitly as the primary item for which it wanted PHMSA to report best practices. The commenter opposed the NPRM's proposal for operators to choose from PHMSA-prescribed methods to address emissions control during a blowdown, reasoning that the methods PHMSA proposed would be unsupported. The commenter called for PHMSA to give operators flexibility and discretion so that they may address blowdowns without undue burdens and restrictions.

Atmos Energy Corporation noted that each venting event is unique; thus, operators should have the flexibility to design their mitigation approaches without restrictions.

Williams Companies, Inc. asked PHMSA to clarify various provisions in § 192.770. First, they asked if, when an operator evaluates transmission compression fleet capability of how far suction pressure can be drawn down with minimal reconfiguration under typical operating suction pressures, whether the low compression ratio compressor configurations on transmission assets can be used to draw down the pipeline below the 50 percent threshold before blowdown. The commenter then requested PHMSA clarify whether the 50 percent reduction threshold applied to all methods of emissions reductions or just the alternative methods. Third, the commenter requested PHMSA clarify how the operator should calculate the initial volume. Lastly, the commenter requested PHMSA clarify how an operator could calculate a reduction when the operator is using isolation valves on a segment. The Joint Environmental comment also requested that PHMSA clarify how operators should calculate the original unmitigated emissions estimate for a blowdown as well as the estimated mitigations for the listed options.

Multiple commenters, including the Industry Trades, INGAA, Williams Companies, Inc., Philadelphia Gas Works, and Kinder Morgan Inc., stated that operators would need more than 6 months to prepare for complying with § 192.770. These commenters suggested that operators would need to consider a host of issues prior to the purchase or rental of temporary compressor units, including mechanical capability, infrastructure siting, air compressor or compressor power, liquids management, equipment and hose maintenance, and fleet size. INGAA noted that it is not reasonable nor practical to expect operators to have mobile compression on standby when each operator conducts operations, maintenance, and repair activities that require an intentional release of gas. They also noted that many transmission rights-of-way are in remote locations, and operators may face delays to secure mobile compression at the scene; furthermore, they commented that mobile compressor companies would likely be unable to accommodate the increase in demand and need time to ramp up operations.

Exception for Undue Customer Burden

Williams Companies, Inc. requested that PHMSA factor in outage time, impacts to customers, impacts to communities, and time needed to for operators to begin pressure reductions in service of emissions mitigation. Similarly, the TPA and the TCC stated that operators need flexibility to respond to changing or unplanned conditions to avoid the possibility of extended downtime and resulting outages to the public. The Industry Trades and INGAA supported proposed § 192.770(b) and suggested PHMSA expand the exemption for emergencies to include safety risks in the judgment of the operator and potential commercial impacts. Philadelphia Gas Works commented that PHMSA should expand the proposed exception for emergencies to include scenarios where the operator deems there is a safety risk or potential commercial impact that necessitates the venting of gas.

Documentation—Proposed § 192.770(c)

The Industry Trades commented that PHMSA should clarify that the documentation requirement in this section could be satisfied through operators developing and implementing written procedures that apply to the pipeline, stating that operators should not be required to document the application of the methodologies used to mitigate the release of gas for each intentional release because this would lead to undue recordkeeping burdens. Enstor Gas, LLC and an individual commenter urged PHMSA to delete the second part of proposed § 192.770(c), which would require operators to describe how the methodologies minimize the release of gas to the environment because PHMSA already determined which methods are acceptable as a part of the proposal.

Limitations on Flaring

In the NPRM, PHMSA sought comment on whether it was appropriate to restrict operators from using flaring only if other mitigation methods were impractical. The PST asked that PHMSA clearly articulate that operator reliance on flaring should be reduced substantially and should be reserved for situations when other mitigation options are impractical or present safety risks. They elaborated that, while effective at reducing the amount of emitted methane, the technique still releases carbon dioxide, water, and possibly other contaminants. The Industry Trades asked PHMSA to clarify what the criteria would be for an operator to prove that other abatement measures were impractical and believed that flaring should not be considered a method of last resort insofar as it can be used with other mitigation methods to empty a pipeline in a timely fashion.

INGAA and the Industry Trades urged PHMSA to permit the continued use of flaring and not to restrict its use, reasoning that flaring can reduce the effect of emissions on climate change by up to 25 times. They argued that, because the NPRM proposed to accept a 50 percent reduction in vented volume as a sufficient threshold for an operator's emission reduction method, flaring should be acceptable to PHMSA as a primary method for operators to reduce emissions. Atmos Energy Corporation also expressed support for using flaring, noting that it may be required for operators to run ILI tools for IM purposes and could be used in conjunction with other emission-reduction practices, such as drawdowns and in-line compression, to reduce emissions.

The MD Attorney General et al. supported a tiered regulatory approach that distinguished between practices that have the potential to prevent releases and those that could be used to minimize any unavoidable emissions. The commenter also suggested that PHMSA specify operational steps that an operator could use—alone or in tandem—to reduce the amount of gas in a pipeline segment requiring maintenance. The commenter then suggested that PHMSA could require the regulations to specify that, once an operator has taken those measures, the operator must attempt to route the remaining gas to storage. If this was not feasible, the commenter stated, PHMSA could require the operator to attempt to route the gas to another useful purpose. If this is infeasible, the commenter stated, then PHMSA could require the operator to attempt to route the gas for flaring. Finally, if none of those options were feasible, PHMSA could allow the operator to vent the remaining gas to the atmosphere.

An individual commenter argued that PHMSA should prohibit operators from venting and flaring because both methods emit methane. The commenter stated that flaring also emits toxins and provided a list of contaminants with associated global warming potential, such as nitrous oxide, methane, particulate matter, and reactive organic gases. The Joint Environmental comment stated that while flaring is clearly preferable to venting gas, operators should use it as a last resort to reduce emissions after operators have used all other options to reduce gas releases during blowdowns and similar processes.

Minimum Volume Criteria for Blowdowns/De Minimis Release

In the NPRM, PHMSA requested comment on whether it was appropriate to specify a minimum pressure or pressure reduction for pressure reduction methods and any other mitigation methods operators should consider. The Industry Trades suggested that PHMSA should focus on reducing large-volume releases and explained that applying minimum pressure reductions to all pipeline segments undergoing planned venting would be impractical, onerous, and would treat each planned venting as being of equivalent concern in terms of methane emissions impact. Atmos Energy Corporation noted that each venting event is unique; thus, operators should have the flexibility to design their mitigation approaches without restrictions.

Northern Illinois University suggested that permitting short-duration intentional gas releases (no greater than 3 SCFH) during leakage surveys could assist UAV-surveyors to estimate wind and turbulence parameters that affect gas dispersion.[380] They reasoned that releasing this small amount of gas would be justified because it would result in more accurate surveys and could make companies more comfortable in using ALDP technologies.

TC Energy supported limiting proposed § 192.770 to planned releases that exceeded a certain volume of gas. The Industry Trades suggested that PHMSA limit the applicability of proposed §§ 192.770 and 193.2523 to planned releases that would exceed 1 MMCF without mitigation. The PST supported proposed § 192.770 but recommended that PHMSA set standards for operators to follow for each instance of vented emissions to ensure that operators mitigate 50

[380] UAV refers to an unmanned aerial vehicle, which is an aircraft that carries no human pilot or passengers. UAVs are sometimes referred to as drones and can be fully or partially autonomous but are more often controlled remotely by a human pilot.

percent of their emissions using a given technology. Furthermore, Xcel Energy suggested that an alternative to PHMSA striking "reduce" would be to change it to "reduce by 50 percent." Given that it might be impractical for mitigation methods to be leveraged for small intentional releases, the commenter supported PHMSA providing a minimum volume.

Atmos Energy Corporation contended that in § 192.770(a), PHMSA's inclusion of all "intentional releases of gas" was too broad and suggested PHMSA limit the "intentional release of gas" to refer to only "planned repairs, construction, operations, or maintenance."

The Industry Trades and TC Energy asked PHMSA to use the verb "reduce" rather than "minimize" in proposed §§ 192.605(b)(13), 192.770, and 193.2523 because the phrasing as proposed may be interpreted as requiring operators to select the method that achieves the greatest emissions mitigation. They commented that the verb "minimize" renders the flexibility given to operators to select the best mitigation method from a menu of proven options moot. Similarly, Xcel Energy suggested PHMSA revise the section by using the verb "reduce," as the verb "minimize" could be interpreted differently by operators, PHMSA, and State agencies. Furthermore, Atmos Energy Corporation declared that the "prevent or minimize" standard PHMSA proposed in § 192.770(a) was ambiguous; thus, the commenter requested that PHMSA define a de minimis threshold as well as a threshold of a 50 percent reduction, which would align with the EPA's Methane Challenge Program.[381]

[381] The EPA's Methane Challenge Program was active during the comment period but was sunset at the end of 2024 prior to the publication of this final rule.

Philadelphia Gas Works and Kinder Morgan, Inc. encouraged PHMSA to focus on annual emission reductions across an operator's footprint instead of a specific volume or pressure reduction. This would give operators more flexibility while still achieving the same volume of emissions reduction.

Exceptions for Certain Releases

The Industry Trades suggested that operators should also be exempt from using the blowdown mitigation methods for an event that requires immediate investigation of the serviceability of the pipeline facility in proposed § 192.770(b)(1).

General

Williams Companies, Inc. noted that for alternative methods, PHMSA should focus on emissions reduction rather than on volume alone and did not understand why the agency focused only on volume reduction. Additionally, the commenter asked PHMSA to clarify various provisions in § 192.770, including what factors an operator should consider when using its engineering judgment for determining an acceptable section size (i.e., length of pipeline) if no maximum vent rate or section size is defined under § 192.770(a)(1), and whether a release from overpressure protection devices would be considered an emergency events under § 192.615(a)(3) for purposes of applying the exemption to release minimization at § 192.770(b).

The NPRM solicited comment on whether the methods for mitigating blowdown emissions from gas transmission pipelines and LNG facilities should be used for gas distribution or Types B and C gas gathering pipelines. The PST requested that PHMSA apply the gas transmission blowdown mitigation provisions to distribution and all gas gathering lines to ensure that safety and environmental benefits are achieved. On the other hand, the Industry Trades stated that gas distribution lines release smaller volumes of gas due to lower pipeline operating pressures and smaller pipe diameters and concluded that the emissions abated on distribution blowdowns would be negligible to the emissions abated from transmission blowdowns; therefore, until transmission blowdown abatement has been achieved, resources for gas distribution blowdown abatement should be halted.

Comments Specific to LNG Facilities

PHMSA received several public comments related to minimizing emissions at LNG facilities in §§ 193.2503 and 193.2523. NAPSR agreed with and expressed general support for the proposed changes to §§ 193.2503 and 193.2523. Atmos Energy Corporation responded to PHMSA's request in the NPRM by stating that they believed that each venting event is unique, and operators should be provided the flexibility to design their mitigation approaches without restriction. Atmos Energy Corporation supported PHMSA's proposal that alternative emissions mitigations under § 193.2523(a)(4) achieve at least a 50 percent release volume reduction comparted to venting gas or LNG directly to the atmosphere without mitigative action. Philadelphia Gas Works and the Industry Trades suggested that the phrase PHMSA used in § 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.

Williams Companies, Inc. discussed minimizing emission from blowdowns and boil-off in proposed § 193.2523, and asked PHMSA to clarify whether there is a minimum volume associated with the proposed changes. Furthermore, Williams also asked PHMSA to clarify whether operators must demonstrate that the options listed in § 193.2523 are not achievable before a blowdown can take place. The Industry Trades and multiple operators urged PHMSA to consider alternative proposals for minimizing emissions during blowdowns and boil-off operations.

Regarding implementation timelines specific to the mitigation of vented and other emissions from LNG facilities, the Industry Trades and Philadelphia Gas Works urged PHMSA to consider that the proposed 6-month implementation period provided in the NPRM was not reasonable because LNG facilities need time to obtain new or modified air permits to route additional volume to flare.

3. GPAC Deliberation Summary

On November 27 and 28, 2023, the Committee discussion of the NPRM proposals for mitigation of intentional releases of gas (e.g., blowdowns), pursuant to a new § 192.770, began with PHMSA's summary presentation of the proposed regulatory language and its supporting reasoning, including a discussion of its cost and benefits, and an overview of material comments from stakeholders on the proposal. The Committee then provided opportunities for stakeholders present at the meeting to present their feedback. Among the handful of stakeholders taking this occasion to provide feedback were representatives of large transmission pipeline operators, the gas gathering industry and publicly owned gas distribution utility trade associations. Commenters referenced their written comments and highlighted anxieties of their members regarding the potentially high implementation costs of the intentional release mitigation requirements—particularly given that blowdowns, in particular, may need to occur more often in light of the enhanced repair obligations elsewhere in the NPRM. Some industry stakeholders also contended that broad language in the proposed regulatory text would create overly burdensome documentation requirements or ever-increasing demands by PHMSA for operators to select more and more of the potential mitigation options identified in § 192.770 as proposed.

Committee members then discussed at length PHMSA's proposed regulatory language. Committee members representing industry, including those with significant gas transmission, gathering or distribution assets, expressed several implementation concerns associated with the high cost of relatively novel blowdown mitigation tools, such as recompression, and the enforcement risks to operators from PHMSA's use of broad language ("minimize emissions") guiding operators' selection from the "menu" of blowdown mitigation options in § 192.770. Those Committee members representing industry generally called for PHMSA's final rule to incorporate elements (e.g., a relaxation of the "minimization" language; less onerous reporting or documentation requirements; de minimis volume thresholds to focus any new regulatory requirement on the highest-volume blowdowns; and broader exceptions to protect downstream customers and public safety) to give operators more flexibility in their compliance efforts and avoid "locking-in" technologies in a fast-developing area of industry operations. Members representing the industry also emphasized the importance of retaining access to flaring as an appropriate and effective methane emissions reduction tool in many circumstances. Some Committee members representing State pipeline safety representatives echoed those concerns, noting in particular that any potentially large compliance costs could have rate consequences for consumers, as compliance costs are passed along by operators. Other members of the Committee, including those representing the public, encouraged the Committee to evaluate PHMSA's proposal through the prisms of a climate crisis where large-volume, intentional methane emissions from blowdowns are a principal contributor, as well as the congressional mandate in section 114 of the PIPES Act of 2020 requiring operators to minimize those emissions. Some of those Committee members representing the public consequently suggested a recommendation that PHMSA adopt a systems-based methane emissions approach that would create performance targets for methane emissions reduction across both intentional releases and leaks. Committee members representing the public also emphasized the informational value (to the public, researchers and regulators alike) of broad documentation and reporting requirements related to intentional release mitigation, highlighted their concern about operator reliance on blowdowns as a mitigation strategy, and expressed concern regarding the incorporation of higher de minimis thresholds and broad exceptions (e.g., for public safety or to prevent downstream customer impacts) within the rulemaking.

The Committee discussion of the NPRM proposals for blowdown and boil-off mitigation (i.e., minimization of releases) at LNG facilities described at §§ 193.2503 and 193.2523 occurred on Monday, March 25, 2024, within a broader discussion of all proposed requirements for LNG facilities and facilities transporting hydrogen gas and blends of hydrogen gas and natural gas. During the opportunity for stakeholders to provide feedback during the meeting, a commenter representing multiple operators suggested that PHMSA should consider alternative proposals by the industry—presumably meaning those alternatives proposed in their submitted, written comments—that were equivalent to minimizing emissions during blowdowns and boil-offs. The

Committee discussion centered on whether the proposals related to emissions minimization during blowdowns, boil-offs, and other intentional releases for LNG facilities was specifically tailored for LNG facilities or if it was mirrored from the transmission requirements (which had been previously discussed and voted on by the Committee), with several members of the Committee expressing opinions contrary to one another. Committee members representing the industry emphasized the impracticability of applying the transmission mitigation requirements to LNG facilities based on the differences in design and operational characteristics. Committee members representing the industry voiced concerns about the maturity of minimization capabilities at LNG facilities and the practicability of meeting a 50 percent volume reduction, suggesting that even a 10 percent volume reduction might not be possible. Committee members representing the industry suggested that PHMSA should study effective blowdown practices for LNG facilities in order to develop more narrowly tailored methods for LNG operators. Committee members representing the public responded that the 50 percent volume reduction was proposed as just one of several available methods, all of which were not proposed to require a release volume reduction of 50 percent. These Committee members and a Committee member representing the government, highlighted the proposed flexibility in the methods available to LNG operators to comply with the minimization requirements and noted that PHMSA had included a considered approach to LNG facility blowdown mitigation in the NPRM. A Committee member representing the public suggested that detailed reporting on mitigation efforts could provide PHMSA and other stakeholders with a better understanding of what methods are effective for LNG facilities. Ultimately, the Committee arrived at a recommendation that PHMSA could take the proposed language and further consider the unique characteristics of LNG and LNG facilities in moving forward to finalize the minimization methods. Consensus from the Committee was reached after comments were made expressing that the will of the Committee, as it pertains to minimizing emissions from LNG facilities, was that PHMSA should review the appropriateness of each of the proposed minimization methods—including considering the differences in complexity among LNG facilities—and if necessary, refine or rewrite the methods with consideration to the unique characteristics of LNG facilities.

4. GPAC Recommendation

The Committee's recommendations on § 192.770 reflect a thoughtful and informed discussion between Committee members regarding how PHMSA could tweak its proposal to navigate the different considerations described above. Those recommendations were as follows:

- In the first vote, the Committee unanimously recommended that PHMSA consider the available data on releases from blowdowns and create an exception to § 192.770 for non-emergency blowdowns with a de minimis release volume. Specifically, the Committee recommended to PHMSA that the following de minimis emissions from blowdowns of large-diameter pipeline segments be included in the § 192.770 exception: blowdowns of launchers and receivers that may not be within the confines of a compressor station; blowdowns from work on measurement and regulation stations; blowdowns from maintenance work on compressor units and associated equipment including relief systems and filter separators; blowdowns to conduct an immediate anomaly repair and excavation; and emergency shutdown device testing, as relevant.

- In the second vote, the Committee recommended 14 to 1 that PHMSA provide an exception to § 192.770 when there would be a significant negative impact to customers and outline scenarios that would affect customer outages.
- In the third vote, the Committee unanimously recommended that PHMSA limit the sole use of flaring to scenarios when other options are impractical, unsafe, or result in lower emissions abatement. Furthermore, the Committee also supported PHMSA's continued research and development to advance technology and noted its recommendation was not intended to limit technological advancement in this area.
- In the fourth vote, the Committee unanimously recommended PHMSA to require, in accordance with § 192.770(c), operators document in their procedures which methodology the operator selected and how the chosen methodology complies with § 192.770(a).
- In the fifth vote regarding the proposed blowdown and boil-off mitigation requirements for LNG facilities at § 193.2523, the Committee also unanimously recommended that PHMSA consider the unique characteristics of LNG plants, including reviewing the appropriateness of each of the methods PHMSA listed in proposed § 193.2523(a)(1)-(4).

Although much of the Committee discussion focused on consideration of the value of recommending precise language regarding the scope of potential exceptions and specific numerical thresholds for intentional release requirements, the Committee's recommendations ultimately settled on identifying broad principles for PHMSA' s consideration in adjusting § 192.770 to improve operator implementation flexibility and reduce costs while still ensuring meaningful emissions reductions. The Committee's recommendations also explicitly recommended retaining flaring as an available methane mitigation method as appropriate to ensure public safety, minimize consumer impacts, and yield robust emissions mitigation and data development for technological advancement in emissions minimization. Lastly, the Committee also ultimately decided against recommending a system-wide performance standard for emissions reduction, primarily because of practicability concerns.

5. PHMSA Response

<u>Transmission Blowdowns</u>

In response to comments opposing the proposed requirements in § 192.770, as previously mentioned, this final rule codifies in regulation the section 114 mandate of the PIPES Act of 2020 requiring operators to have a written plan that addresses minimizing releases of natural gas. This provision is essential for executing PHMSA's mission to ensure the protection of people, property, and the environment. Approximately a quarter of annual methane emissions from U.S. natural gas transmission pipelines are from vented emissions, including blowdowns, according to the GHGI data described in section II.B. For LNG facilities, blowdowns represent approximately 43 percent of methane emissions, and for storage appurtenant to LNG facilities, blowdowns account for as much as 66 percent of methane emissions. Minimizing non-emergency vented emissions is crucial for reducing methane emissions; in addition to the emissions abatement benefits from isolating shorter segments for maintenance tasks, this approach can have operational benefits from reducing or eliminating downtime by bypassing the shut-in segment. In addition to methane emissions, minimizing release volumes of other jurisdictional gases—which are by definition toxic, flammable, or corrosive—from pipeline blowdowns reduces impacts to public safety, public health, and the environment from gas pipeline O&M activities. According to gas transmission annual reports for the 2023 calendar year, after natural gas, the most significant commodities transported by volume in gas transmission pipelines were landfill gas (predominately composed of methane gas blended with carbon dioxide),[382] and hydrogen gas. All other gases represent a negligible share of the volume of gas transported by onshore gas transmission pipelines, consisting mostly of synthetic gas (hydrogen gas blended with toxic carbon monoxide), undefined "off gas," "fuel gas," or "residual gas," and ethylene. All other gases also included various forms of methane gas, including biogas and coalbed methane. Generally, the mitigation options provided in the final rule, or an equivalent alternative method, are compatible with other toxic, flammable, or corrosive gases. While some toxic but non-flammable commodities transported by gas transmission pipelines in small quantities such as chlorine, hydrogen chloride, and carbon monoxide are not conducive to flaring, operators of such pipelines may employ any combination of the other available methods in § 192.770(a) suitable to each regulated gas, and the avoidance of human health impacts related to releasing toxic gases to the atmosphere justifies preventing and minimizing the releases of such gases.

In response to the comment that PHMSA should set standards to ensure that operators mitigate 50 percent of their emissions using a given technology, the NPRM did not include a proposal to require operators to mitigate a certain percentage of their emissions, but to minimize

[382] EPA Landfill Methane Outreach Program. "Basic Information about Landfill Gas." (April 25, 2024). https://www.epa.gov/lmop/basic-information-about-landfill-gas. Last accessed September 13, 2024.

the release of natural gas using proven methods. Accordingly, PHMSA declines to set an emissions mitigation percentage but expects operators to employ any one or combination of the available methods in § 192.770(a)(1) through (7) to minimize releases of gas to the fullest extent possible. Should an operator select the alternative method under § 192.770(a)(6), the operator is required to document the calculations justifying how the alternative method was necessary per § 192.770(d)(2) in addition to the requirements in § 192.770(d)(1).

In response to the request that operators report for each release a comparison of unmitigated release emissions and the actual emissions occurring while using the selected method, PHMSA did not propose to require operators to report their reasoning for selecting any one of the particular the emissions minimization methods listed in proposed § 192.770(a)(1) through (6). Due to the agency's inability to notice and subsequently receive stakeholder feedback on this commenter's suggestion in this proceeding, this final rule does not include such a requirement. PHMSA intended that selecting any of the methods listed in proposed § 192.770(a)(1) through (6) would satisfy the requirement to minimize the release of gas.

In this final rule, PHMSA makes an editorial amendment to proposed § 192.770(a)(2) and has struck the phrase "from the nearest isolation valves or control fittings," as this was a description of the method an operator would take to route the gas.

In response to the comment requesting PHMSA require operators to publicly report their efforts to mitigate intentional emissions, PHMSA did not include a proposal for operators to publicly report their efforts to minimize intentional emissions in the NPRM. Section IV.F. of the

NPRM discusses this in more detail.[383] Therefore, PHMSA declines to adopt this suggested requirement in this final rule. However, this final rule does codify recordkeeping requirements for operators minimizing the intentional release of natural gas under this section. This final rule also requires operators, in accordance with § 192.770(c)(5), to notify PHMSA and the appropriate State authority as early as practicable in accordance with §§ 192.18(a) and (b) when minimizing the release of gas would lead to a substantial negative impact to customers' health or safety due to a prolonged loss of gas supply. For the methods being finalized at §§ 192.770(a)(1) through (a)(5), PHMSA does not expect an operator to document how the chosen method or methods for each release minimized emissions for each release if an operator's O&M procedures prescribe the usage of the methods at § 192.770(a). To the extent that a release meets the threshold for an LVGR report, an operator is required to include that release on Form F 7100.5 – Large-Volume Release Report in accordance with § 191.19. PHMSA will consider summary statistics on blowdowns for future annual report revisions. Since PHMSA did not notice and solicit comments from stakeholders and the public on reporting this type of event, it would like to receive public comment on future information collection activities before implementing this reporting requirement.

In response to the comment from Energy Transfer, LP, regarding a report PHMSA was required to issue in accordance with the PIPES Act of 2020, the report responding to the congressional mandate on the best available technologies, practices, and designs to prevent or minimize releases was issued on August 16, 2024 (PHMSA's 2024 Best Available Technologies

[383] 86 FR 31890, at pgs. 31947-31949. (May 18, 2023).

Report),[384] The practices in this final rule were recognized in the report. PHMSA's 2024 Best Available Technologies Report primarily concerns pipeline design; however, sections 5 and 6 address some potential methods for preventing and mitigating operational and maintenance related releases. Incorporating the statutory language from the section 114 self-executing mandate into the regulations does not depend on the contents of that report, though the methods described in the report may help operators demonstrate compliance with the procedure manual revisions required by section 114. Additionally, the blowdown mitigation methods in this final rule are consistent with examples in sections 5 and 6 of the report and previously recognized best practices. Section II.B.3. explains that emissions from blowdowns are known to be a significant source of emissions from gas transmission pipelines. The minimization methods included in this final rule have been established as best practice by the EPA, and these methods are also supported by INGAA through its industry commitment. Specifically, the EPA Natural Gas STAR program listed blowdown volume mitigation among several cost-effective and recommended methods for reducing methane emissions from operations, maintenance, and construction. [385] Additionally, the EPA's voluntary Methane Challenge Program identified various methods of reducing or eliminating blowdown emissions similar to those in this final rule. Further, INGAA included minimizing blowdown volume in a list of commitments that

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[384] PHMSA. "Report to Congress – Review of Best Available Technologies or Practices and Pipeline Facility Designs for Preventing or Minimizing Natural Gas Releases During Planned Operations and Maintenance." (August 16, 2024). https://www.phmsa.dot.gov/news/report-congress-review-best-available-technologies-or-practices-and-pipeline-facility-designs

[385] See EPA Methane Mitigation Technologies Platform, "Route Blowdown Gas to Low Pressure System." (July 9, 2024) https://www.epa.gov/natural-gas-star-program/route-blowdown-gas-low-pressure-system.

member companies are making to address methane emissions.[386]PST has identified similar mitigation options in public comments previously submitted in response to the 2016 NPRM titled "Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines,"[387] including a report from M.J. Bradley and Associations containing example mitigation options.[388]

In response to the comment requesting PHMSA allow operators to have unrestricted flexibility for designing their mitigation approach under this section, operators have a menu of options to choose from for minimizing a release, including an alternative method at § 192.770(a)(6), which PHMSA expects will provide sufficient flexibility to operators without undermining reductions in emissions.

PHMSA appreciates the queries regarding proposed § 192.770. The use of in-line compression does not include a requirement for an operator to reduce the release volume by 50 percent, and in using the method at § 192.770(a)(3), if the operator has reduced the pipeline pressure by using the low compression ratio compressor configuration, then this would be acceptable emissions minimization prior to the planned activities. In addition, the 50 percent threshold applies only to the alternative method at § 192.770(a)(6). PHMSA's intent in this section is to provide more options to operators to minimize the amount of natural gas released to the atmosphere, and at the present time, PHMSA has identified methods § 192.770(a)(1) through (5) and (7) as suitable means for operators to minimize the methane emissions without

[386] https://www.ingaa.org/File.aspx?id=38582 (last accessed Sept. 3, 2024). 2

[387] 81 FR 20722. (May 13, 2016). https://www.regulations.gov/comment/PHMSA-2011-0023-0272.

[388] Lowell, Dana et.al. "Analysis of Pipeline and Hazardous Materials Safety Administration Proposed New Safety Rules: Pipeline Blowdown Emissions and Mitigation Options." (June 2016). (PHMSA-2011-0023-0272).

prescribing a minimum emissions reduction threshold. In response to the comment requesting that PHMSA clarify how to calculate the initial volume or potential emissions, PHMSA urges operators to use normal operating pressure and conditions, unless the operator is aware of alternative values that would improve accuracy.

In response to concerns regarding the compliance deadline for these provisions, section III.U contains a more in-depth discussion regarding the compliance timelines of this final rule.

Exception for Undue Customer Burden

Prolonged outages could have a negative impact to public health and safety. PHMSA generally agrees with the Committee's recommendation to include an exception to these provisions for when there would be a significant negative impact to customers, such as outages or a significant rate shock.

The Committee recommended PHMSA address scenarios that would affect customer outages. PHMSA implemented this recommendation in this final rule by permitting an exemption to minimizing the release of gas if there is a significant negative impact to customers. In this final rule, at § 192.770(c)(5), a negative impact to customers' health or safety shall be the benchmark used to determine a significant impact to customers. Evidence of operator coordination with the economic regulator (e.g., the applicable State Utility Commission or equivalent or Federal Energy Regulatory Commission) can be included in the justification an operator would provide in accordance with § 192.770(c)(5). In some locales there are limited windows of availability to perform scheduled maintenance activities that may also include performing blowdowns. PHMSA expects operators to use their best judgment to plan maintenance activities during times of the year when potential outages would have a negligible impact to customers' health and safety. PHMSA expects that limiting this exemption to extraordinary circumstances where minimizing the release of gas in accordance with § 192.770 would lead to a more-than-negligible negative impact on customer health and safety will help ensure that operators minimize emissions when safe and practicable, while also protecting the public's health and safety from the potential impacts of severe and prolonged outages.

In response to comments requesting the expansion of the exception for emergencies to include safety risks in the judgement of the operator and potential commercial impacts, some affected operators may already have adopted protocols for minimizing vented emissions and eliminating leaks from their facilities either voluntarily (e.g., to minimize loss of a commercially valuable—and hazardous—commodity) or in response to State or Federal requirements (including, but not limited to, the self-executing mandate in section 114 of the PIPES Act of 2020). PHMSA believes the previously discussed exception in § 192.770(c)(5) adequately addresses these comments.

Documentation

This final rule adopts the Committee's recommendation to clarify that operators are required to document in their O&M procedures how the methodologies are used to comply with § 192.770(a) and meet the other requirements in that section. This contrasts with the proposed requirement in the NPRM that implied that operators had to provide an explanation on how they minimized releases for each blowdown event. This change targeting standard practices rather than individual events is consistent with the intent of the NPRM and section 114 of the PIPES Act of 2020.

Additionally, this final rule clarifies that operators using any of the listed methods at § 192.770(a) are complying with the requirement to minimize intentional releases of gas to the environment. This is consistent with the Committee recommendation to clarify that using any of the listed methods in paragraph (a) is sufficient to demonstrate compliance with § 192.770. Accordingly, PHMSA has removed the proposed requirement for operators to document a description of how methods described by paragraphs (a)(1) through (a)(5) minimize the release of gas to the environment. Operators are still obligated to minimize emissions and document those minimization efforts but removing the per-event analysis requirement for the methods described by paragraphs (a)(1) through (a)(5) reduces compliance costs and recordkeeping burdens associated with performing and documenting such analyses on a per-event basis.

This final rule adopts the proposed requirement that operators must document the release and the method or methods used for all intentional releases at § 192.770(d). Additionally, this final rule requires operators, when using either the alternative method at § 192.770(a)(6) or the sole use of flaring method at § 192.770(a)(7)—and the corresponding limitations described at § 192.770(b)—to document the justification and calculations supporting the usage of those methods. The requirements finalized at § 192.770(d) clarify that an operator must calculate the estimated release volume prior to the performing an intentional release to determine minimization method selection, and if necessary, confirm or update estimated release volumes with actual release volumes after performing an intentional release. And finally, this final rule adopts the proposed requirement that operators must document releases conducted without minimization according to paragraph (c) of this section by including documentation of the release and the justification to perform the release without minimization.

Limitations on Flaring

Based on concerns raised in public comments and the recommendation of the Committee, PHMSA is specifying in this final rule that operators are permitted to solely use flaring as an emissions mitigation technique when other options are impracticable, unsafe, or are calculated to result in higher CO_2 equivalent emissions than the emissions from the sole use of flaring.[389] An operator using flaring as the sole method of emissions minimization must maintain records of the justification and calculations supporting its determination that the other methods listed in § 192.770 were impracticable, unsafe, or would result in higher equivalent emissions than the emissions from flaring.

Flaring can be an effective method to minimize emissions by burning gas rather than releasing it directly into the atmosphere. However, while well-designed and maintained flare stacks can combust gas with almost 100 percent efficiency, leaks and incomplete combustion can reduce the efficiency of flare stacks to approximately 90 percent. Therefore, PHMSA believes that flaring is best used in conjunction with the other proven methods under § 192.770(a), unless

[389] The GPAC recommended the phrase of "lower emissions abatement." From a plain language perspective, the agency decided to use the phrase "higher emissions" to reflect this intent. The addition of the phrase "CO_2 equivalent" makes it clear that operators are expected to consider both the carbon dioxide and methane emissions when evaluating the GHG impacts from flaring in this analysis.

those methods are shown to be impracticable, unsafe, or result in higher equivalent emissions than flaring alone.[390]

In this final rule, and in accordance with the Committee recommendation, PHMSA is allowing operators to use flaring without restriction when operators use it to supplement other methods of emissions minimization. Some methods of emissions minimization for blowdowns, such as pressure reduction or reducing the length of the blowdown segment with control fittings, still result in residual gas that must be released or captured. Allowing an operator to flare that remaining gas means the operator will not release that gas to the atmosphere, reducing total emissions.

PHMSA expects operators to use the global warming potential (GWP) of 25 for methane. This is consistent with the EPA's 40 CFR part 98 regulations in Table A-1 of § 98.2.[391] CO_2 equivalent is the number of metric tons of CO_2 emissions with the same global warming potential as one metric ton of another GHG.[392] GWP refers to the ratio of the time-integrated radiative forcing from the instantaneous release of one kilogram of a trace substance relative to that of one kilogram of a reference gas (*i.e.,* CO_2). GHGs include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and other fluorinated gases. These definitions were drawn from 40

[390] Duren, Riley and Deborah Gordon. "Tackling unlit and inefficient gas flaring," *Science*. Vol. 337 Issue 6614. (2022): 1486-1487. https://www.science.org/doi/full/10.1126/science.ade2315.

[391] In reporting to the GHGRP, facilities are required to apply a global warming potential of 25 metric tons of carbon dioxide equivalent for methane (40 CFR 98, Table A-1 to Subpart A of Part 98). Beginning in 2025, reporters to the GHGRP will be required to apply an updated global warming potential of 28 for methane (89 FR 31812).

[392] 40 CFR 98.6.

CFR part 98, subpart A; however, PHMSA declines to directly cite these regulations as future changes are out of the control of the agency.

The carbon dioxide equivalence of another GHG or GHGs is calculated using the following equation.

PHMSA declines to develop a tiered, or sequenced, regulatory approach to emissions minimization in this final rule in a manner that was described by public comments. This final rule aims to provide flexibility to operators to determine and select the best method(s) for minimizing intentional releases considering that a different method or combination of methods may be best suited for different types of scheduled activities. PHMSA partially incorporated a sequenced approach with respect to flaring as PHMSA is only allowing operators to use flaring if §§ 192.770(a)(1) through (6) are impractical, unsafe, or are calculated to result in higher carbon dioxide equivalent emissions than the emissions from flaring.

Minimum Volume Criteria for Blowdowns/De Minimis Release

Consistent with the Committee's recommendations, PHMSA is adopting in this final rule a volume criterion of 500,000 standard cubic feet (0.5 MMCF), below which an operator would not be required to apply the release minimization requirements of this final rule. This threshold represents the limit to the maximum volume an operator would be permitted to release without applying one or more of the minimization methods (unless another criterion in the exemption at § 192.770(c) is met); this volume threshold is consistent with the pre-minimization release volume that would be reported under the new LVGR reporting requirement at § 191.19 in the absence of mitigation. Consistent with the Committee deliberations on the topic and public comments received, this will generally target blowdowns of mainline transmission and Type A gas gathering piping, which can individually consist of very large volumes. To prevent this criterion from applying to smaller releases that may occur during maintenance activities, PHMSA clarifies that this minimum volume criterion only applies in the event of an intentional release. This should also satisfy the request in the public comments for PHMSA to permit short-duration intentional gas releases for purposes of providing small, known releases to calibrate leak detection equipment during leak surveys.

In response to comments requesting an annual emissions reduction across an operator's footprint, PHMSA would need to define a performance standard for an operator's program to determine the effectiveness of reducing emissions at 50 percent. PHMSA did not propose such a threshold for the minimization methods in proposed § 192.770(a)(1) through (5), and any performance standard or alternative regulatory structure would benefit from public comment. Therefore, PHMSA is declining in this final rule to adopt standards or requirements for annual emissions reductions across operator footprints.

In response to a comment stating that PHMSA's use of the proposed phrase "intentional releases of gases" was too broad, PHMSA partially adopts the commenter's proposed phrasing. PHMSA appreciates the comment that this language is potentially broad; however, PHMSA has chosen to retain the phrase "intentional releases of gas" in this final rule. However, PHMSA is including at § 192.770(a) examples of intentional releases of gas that include, but are not limited to, blowdowns or venting for scheduled repairs, construction, operation, or maintenance.

PHMSA has also taken steps to specify instances where operators would be exempted from compliance with the requirements at § 192.770(a) and (b) and believes that these examples and the specific exemptions at § 192.770(c) provide sufficient clarification to operators.

In response to comments requesting PHMSA use the verb "reduce" instead of "minimize" in § 192.770, PHMSA declines to adopt the commenters' suggestion and notes that this section in this final rule codifies the language from section 114 of the PIPES Act of 2020, which uses the term "minimizing" rather than "reduce." The regulatory text at § 192.770 prescribes proven methods that operators may employ individually or in combination to comply with the requirement to minimize releases of gas and therefore demonstrate compliance with this section and with section 114 of the PIPES Act of 2020.

Exceptions for Certain Releases

The GPAC recommended PHMSA create an exception to § 192.770 for non-emergency blowdowns with a de minimis release volume and provided a list of blowdown scenarios from large-diameter pipeline segments. During the development of this final rule, PHMSA considered these scenarios and recognized that establishing a single volume criterion for all the recommended scenarios would not be possible because of release volumes from certain recommended scenarios would likely dwarf release volumes from other scenarios.

PHMSA appreciates the safety and practicability concerns associated with certain pipeline repair activities and emergency shutdown system testing discussed by the Committee and its recommendation for inclusion within the exemptions at § 192.770(c). In recognition of the disparity between the customary release volumes for certain exceptions and the difficulty in setting a single "de minimis" release volume that is appropriate for the listed blowdowns recommended by the Committee, namely a release necessary to test an emergency shutdown device or to conduct an immediate anomaly repair and excavation, PHMSA is including in this final rule two explicit exceptions for those two scenarios for which the recommended "de minimis" volume criteria will not apply in this final rule. As an editorial note, the phrasing of finalized § 192.770(c)(3) deviates from the Committee-recommended terminology of emergency shutdown device and instead uses the term emergency shutdown system to align with the existing regulatory language at § 192.167.

In this final rule at § 192.770(c)(4), PHMSA is providing an additional exemption from the requirement for operators to minimize the release of gas, in accordance with paragraphs (a) and (b) of § 192.770, for releases associated with the response to an immediate repair condition per § 192.933(d)(1) or § 192.714(d)(1), or for the repair of a grade 1 leak per § 192.760. An immediate repair condition or a grade 1 leak represent a significant risk to public safety and the environment. While operators should minimize emissions to the extent practicable in these three scenarios, this final rule permits an operator to not use emissions minimization methods for associated blowdowns, as this could prolong or increase the danger to property, the public, or the environment. PHMSA has also provided an exception from the emissions minimization requirements in this final rule for emergency shutdown system testing. Emergency shutdown systems are designed to remove gas from a pipeline or pipeline facility as fast as possible during an emergency. While full demonstration emergency shutdown system testing releases a very large volume of gas, it is necessary to help ensure that safety systems work properly during an emergency.

In response to a request from the Industry Trades to exclude an event that requires immediate investigation of the serviceability of the pipeline facility from using blowdown mitigation methods in proposed § 192.770(b)(1), PHMSA understands the commenter's proposed language of "immediate investigation of the serviceability of the pipeline facility" to refer to response to, and investigations associated with, emergency response and urgent repair conditions. These types of immediate investigations are covered by the exception for emergencies and immediate repair conditions and grade 1 leaks at § 192.770(c)(2) and (c)(4), respectively. In this final rule, § 192.770(c)(4) addresses the commenter's concern by explaining that a release associated with responding to and repairing an immediate repair condition would be exempt. This may include releases necessary to investigate the serviceability of a facility as part of the response to an immediate repair condition or grade 1 leak. PHMSA adopted this approach as "grade 1 leak" in § 192.760 and "immediate repair condition" in §§ 192.714(d)(1) and 192.933(d)(1) are well-described terms with specific criteria and response requirements, whereas the commenter's proposed terminology of serviceability is undefined.

General

In response to concerns regarding the cost assessment for blowdown mitigation methods, PHMSA has updated the RIA for this rulemaking and more thoroughly discusses and addresses the comments received on the PRIA in that document.

In response to the miscellaneous comments that Williams provided, PHMSA acknowledges the value of preventing operational releases in the first place. To the extent that operators use methods, such as hot tapping and combining maintenance activities to ensure that a release is calculated to be below 0.5 MMCF, this final rule addresses such circumstances insofar as operators are not required to use additional minimization methods per § 192.770(c)(1).

PHMSA did not propose a definition for an acceptable length under § 192.770(a)(1); therefore, PHMSA didn't adopt one in this final rule. An operator should use its best effort to minimize the length of pipeline, and therefore the amount of gas to be released to complete the required task. An operator should consider operational considerations and options regarding the installation of temporary controls or fittings to reduce the amount of pipeline or pipe necessary to vent. Regarding releases from an overpressure protection device and whether such a release would qualify as an emergency under § 192.615(a)(3), PHMSA based the requirements in § 192.770 on planned intentional releases. A release from an overpressure protection device to control the pressure on the pipeline would be considered an unplanned event. While overpressure protection devices are designed to release gas to protect the pipeline, and such releases could be considered intentional through the nature of their design, they typically provide relief from, and operate during, emergency situations rather than the normal course of operation.

PHMSA appreciates the comments it received regarding whether the transmission blowdown mitigation requirements should be applicable to Types B and C gas gathering lines as well as gas distribution lines. Similar to gas transmission lines, gas gathering and gas distribution lines have intentional releases as well. However, PHMSA did not propose release minimization requirements for Types B and C gathering lines and distribution lines in the NPRM because the purpose, average volume, and frequency of intentional releases from such facilities differ from transmission lines and Type A gathering lines in ways that impact the appropriate potential scope of minimization requirements for such facilities and available minimization methods. These differences warrant notice and comment regarding requirements applicable to such facilities. PHMSA will consider the comments received when evaluating if it is necessary to propose standards appropriate for such facilities in future rulemaking.

Minimizing emissions at LNG facilities--§§ 193.2503 and 193.2523.

Regarding the recommendation from the Committee pertaining to blowdown and boil-off mitigation for LNG facilities and the discussion during the Committee meeting on the issue, PHMSA proposed a set of four emissions minimization options that were tailored to the unique operations of LNG facilities in proposed § 193.2523. These emissions minimization options, while similar in some regard to the set of five options proposed for gas transmission lines at § 192.770(a), are different from, and do consider the unique characteristics of LNG facilities. However, considering the Committee recommendation and the public comments PHMSA received, PHMSA has performed an additional review of the appropriateness of the emissions minimization methods for LNG plants, considering their unique characteristics, in finalizing this rulemaking.

Regarding the first method proposed by PHMSA in the NPRM at § 193.2523(a)(1) for "isolating a smaller section of the piping segments by use of valve or the installation of control fittings," PHMSA recognizes that the term "control fitting" is not a defined term in part 193;

however, commenters did not propose a definition for this term, nor did industry commenters exclude the term in their suggested revisions to the NPRM's regulatory text. PHMSA supports improving clarity of the regulations where possible and found this proposed minimization method to be more appropriate to gas transmission pipelines and not to LNG facilities. While section 6.3.3.4 of the 2006 version of NFPA 59A is not incorporated by reference into part 193, the standard includes requirements that support "limiting the contained volume that could be discharged in the event of a piping system failure" of an LNG facility. Additionally, reducing the volume through isolating a smaller section of piping could be considered part of an already standard practice used by operators when preparing pipeline segments for a planned release and not an appropriate additional minimization method. PHMSA is therefore removing proposed § 193.2523(a)(1) from this final rule.

Regarding the second proposed method at § 193.2523(a)(2) for "routing gas released from the facility to a flare, or to other equipment for use as fuel gas," PHMSA had included routing gas for use as fuel gas and routing gas to a flare in a single method because these methods are similar in principle. PHMSA appreciates those who commented on PHMSA's request for comments on whether it is appropriate to restrict the use of flaring to instances where other minimization measures are impracticable. In response to those comments, PHMSA agrees that flaring can be a useful tool, among a suite of tools, operators can use to minimize emissions from LNG facilities. PHMSA also agrees that operators can use flaring in conjunction with another method or methods but can also be used as a sole method if the other methods are demonstrated to be impractical, unsafe, or are calculated to result in higher carbon dioxide equivalent emissions than flaring. Accordingly, in this final rule, PHMSA is moving the method of routing of natural gas or LNG to a flare to paragraph (a)(1), noting that the sole use of flaring is subject to the limitation described in paragraph (b). PHMSA is keeping the method for routing of natural gas or LNG for use as a fuel gas in paragraph (a)(2). Regarding the emissions minimization method of transferring natural gas or LNG to a storage tank or local pressure vessel, PHMSA does not intend to limit the means of transfer or the types of facilities to which the natural gas or LNG can be transferred. Transferring LNG to a mobile storage tank or vessel, such as those mounted on trucks or marine vessels would fall under this method and will be allowed by this final rule according to the option in § 193.2523(a)(3). Similarly, this method also includes the reduction of the volume of natural gas or LNG to be released from the LNG facility by use of mobile compression or other means of transfer to another pipeline facility, other piping, vessels, storage tank (mobile or stationary), or LNG facility.

PHMSA is finalizing in this rulemaking the fourth proposed method in the NPRM as written, except for a minor typographical change and its relocation to the end of paragraph (a) to appear at § 193.2523(a)(5) in this final rule. In response to public comments, PHMSA reminds operators that the intent of this option is to allow operators to be able to employ alternative approaches not listed in § 193.2523(a)(1) through (4) for minimizing emissions, provided that the operator can demonstrate that the alternative approach reduces the emissions from the LNG facility by at least 50 percent compared to releasing natural gas or LNG directly to the atmosphere without minimization. This is consistent with the approach used in the EPA's

Methane Challenge Program,[393] provides operators with flexibility to employ techniques and technologies appropriate for the unique operating and environmental conditions of their facilities, and accommodates future advancements in release minimization technologies and practices.

Finally, in considering the methods PHMSA proposed for the mitigation of emissions at LNG facilities as recommended by the Committee, PHMSA recognized the need for an additional method that addresses the use of normal, scheduled, and seasonal vaporization and drawdown operations that reduce the volume needing to be released to perform scheduled activities. Accordingly, PHMSA is including this method in this final rule at § 193.2523(a)(4).

In § 192.2523(c) of the NPRM, PHMSA proposed that the required use of these emissions minimization methods would not be necessary during an emergency resulting in the activation of an operator's emergency procedures under § 193.2509 but noted that any release performed without minimization would need to be documented, including documenting the justification for performing the release without minimization. In consideration of the discussion from the Committee and public comments, PHMSA is including two exceptions in § 193.2523(c) for which emissions minimization is not required; however, these releases are still subject to the same documentation requirements that were proposed in the NPRM. These exceptions are: (1) a release with a calculated release volume of less than 0.5 million cubic feet; and (2) a release occurring during an event resulting in the activation of an operator's emergency procedures

[393] See EPA, "Methane Challenge Program BMP Commitment Option Technical Document" at pg. 21 (May 2022), https://www.epa.gov/system/files/documents/2022-05/MC_BMP_TechnicalDocument_2022-05.pdf (last accessed June 10, 2024).

under § 193.2509. As detailed in the paragraph below, the documentation requirements for justifying these exceptions are being consolidated into § 193.2523(d) of this final rule.

During the drafting of this final rule, PHMSA identified an opportunity to integrate the emissions minimization recordkeeping and exception justification requirements originally proposed in §§ 193.2523(b) and 193.2523(c) into the existing recordkeeping requirements of part 193, subpart F—Operations. Accordingly, in this final rule, PHMSA is consolidating the proposed recordkeeping requirements for emissions minimization into § 193.2523(d) with a reference to § 193.2521 for records maintenance requirements. PHMSA requires operators to create and maintain records that document each release and the method or methods used in paragraph (a) of § 193.2523 to minimize the release of natural gas or LNG from LNG facilities. Certain methods, namely the sole use of flaring described at § 193.2523(a)(1) and the alternative method at § 193.2523(a)(5), will require additional documentation by operators that includes the justification and calculations supporting the use of either of these methods. For operators using solely flaring, the documented justification must also support the sole use of flaring by demonstrating that the other release minimization options listed in paragraphs (a)(2) through (a)(4) are impracticable, unsafe, or are calculated to result in higher carbon dioxide equivalent emissions. As discussed above regarding limitations on flaring, PHMSA expects operators to consider the total emissions resulting from flaring natural gas or LNG when performing the calculations required by the sole use of flaring method described at paragraphs (a)(1) and (b) or the alternative method at paragraph (a)(5).

Records of each unminimized release performed under paragraph (c) of this section include documentation of the release and the justification to perform the release without minimization. These requirements will be applicable for intentional releases that occur after January 1, 2028.

In the RIA, PHMSA concluded that the annualized total monetized benefits of avoided blowdown emissions in 2023 dollars is $321.2 million at a 2% discount rate using a pre-statutory baseline, compared with annualized costs of $102.1 million.

PHMSA evaluated several alternatives. First, PHMSA considered an alternative wherein LNG facilities would not be required to conduct periodic leak surveys and repairs or mitigate release volumes during operational blowdowns. PHMSA did not select this alternative because intentional releases at LNG facilities pose similar risks to the environment and public safety as those from pipeline infrastructure and represent a significant share of emissions. For discussion of this alternative with respect to periodic leakage surveys, refer to the discussion in section III.C. Second, PHMSA considered an alternative that would have required transmission operators to meet an annual target of 50 percent intentional emissions reduction across an operator's entire system. PHMSA did not adopt this alternative, because the cost savings would be minimal, and a 50 percent target may encourage larger intentional releases and may undercut Congress's intent.

N. Design, Configuration, and Maintenance of Pressure Relief Devices—§§ 192.9, 192.199 and 192.739

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA sought to minimize emissions caused by malfunctioning pressure relief devices and other unnecessary releases from poorly designed or configured pressure relief devices. A pressure relief device vents gas to the atmosphere or to a flare when the pressure in the system meets design or configuration actuation criteria[394] to protect the integrity of the system from an overpressure condition. A pressure relief device may malfunction by not activating as required by those criteria, risking an overpressure condition that can cause a loss of system integrity with significant public safety and environmental consequences. A pressure relief device may also malfunction by failing to reseat after an initial release due to a mechanical failure preventing the device from reseating after activation. Additionally, a malfunction may occur when liquid contaminants enter a pressure relief device and freeze the device open or closed such as obstructions to valve closure in cold weather conditions. Alternatively, a pressure relief device may malfunction by operating before the actuation criteria have been met, which results in unnecessary releases of gas to the atmosphere. Similarly, a pressure relief device with design or configuration actuation criteria more conservative than necessary to provide adequate

[394] PHMSA here draws a distinction between design actuation criteria set by a device manufacturer (which generally cannot be changed by an operator) and configuration actuation criteria (which in some cases could be changed by an operator post-manufacture and installation). PHMSA further notes that by "actuation criteria" it means the suite of setpoints (e.g., pressure) and other conditions (e.g., programmable logic) that must be satisfied for a pressure relief device to actuate and cease actuation. For example, actuation criteria may consist of a pressure setpoint at which a pressure relief valve may open, as well as a setpoint for that same valve to close.

margin to an overpressure condition may also unnecessarily release gas. Finally, a pressure relief device where the design or materials are ill-suited for use in a pipeline facility's particular operating and environmental conditions may fail or leak, causing unnecessary releases of gas.

In the NPRM, PHMSA proposed to revise § 192.199 to require operators of all new and replaced, relocated, or otherwise changed gas transmission, distribution, and regulated gathering pipelines to be designed and configured to minimize unnecessary releases of gas by performing and documenting an engineering analysis. The proposals in § 192.199 prescribed a series of elements, which operators would demonstrate using engineering analyses, to minimize emissions. These elements included the choice of design material and function, configuration actuation conditions, pressure relief device piping characteristics, presence of isolation valves to facilitate testing and maintenance, and compatibility of material and design with use. In addition, PHMSA proposed at § 192.773 that, coupled with revisions to § 192.9, all gas transmission, distribution, and part 192-regulated gathering pipeline operators would be required to develop procedures to assess the proper functioning of pressure relief devices on their facilities and to remediate or replace any malfunctioning devices. PHMSA proposed to require an operator repair or replace a pressure relief device immediately if it (1) operated above the pressure limits established in §§ 192.201(a) or 192.739, (2) failed to operate, or (3) otherwise failed to provide reliable overpressure protection due to the potential consequences of overpressurizing the pipeline.

In addition, a pressure relief device that releases gas below the intended set pressure range (including the manufacturer-specified tolerance) also poses a potential hazard to the environment, especially if the device releases gas when the pipeline is operating at normal operating pressure. Therefore, PHMSA stipulated in the NPRM that a pressure relief device that releases gas below the set pressure range requires the operator to take immediate and continuous action with on-site personnel to stop the release of gas and ensure operation while providing adequate overpressure protection. The operator would then need to repair the device or replace it as soon as practicable, not to exceed 30 days. Per the proposal, an operator would also be required to define actions that would be taken to stop the flow of gas in its abnormal operating procedures and could include reconfiguring the relief device.

In either case, an operator would be required to maintain records documenting the proper operation and any remediation or replacement of pressure relief devices for the service life of the facility.

PHMSA proposed a compliance deadline of 6 months after the publication date of the final rule in this proceeding for these pressure relief device provisions, which PHMSA determined would provide operators ample time to develop and implement compliance protocols and manage any related compliance costs.

2. Summary of Public Comments

General

The MD Attorney General et al. supported the NPRM's provision for the design, configuration, and maintenance of pressure relief devices and supported PHMSA's authority to enact these changes. The commenter further stated that PHMSA enacted these changes based on reports of incidents resulting from malfunctioning pressure relief devices, and these changes would help minimize the release of gas to the atmosphere and better protect against environmental and public safety hazards posed by malfunctioning or poorly designed and configured pressure relief devices. The Joint Environmental comment urged PHMSA to finalize proposed §§ 192.9, 192.199, and 192.773 as written, because these sections would improve system safety and reduce negative environmental impacts associated with possible system incidents or ruptures. The PST recommended that PHMSA require, as a performance standard, pressure relief valves that can change in configuration, because valves that are unable to be reconfigured do not offer the flexibility needed to comply with the rule and will contribute to safety risks. INGAA asserted that releases from relief devices and emergency shutdown devices are controlled and are therefore not leaks, further noting that, per existing regulations at §§ 192.167, 192.169, 192.179, and 192.199, operators are required to design certain pipeline components to release gas in a controlled manner without hazard.

Atmos Energy Corporation requested that PHMSA clarify the use of the terms "actuation pressure" and "set actuation pressure range" in the final rule in §§ 192.199(i) and 192.773(a) to avoid confusion, noting that these terms are vague, do not provide adequate guidance, and do not reflect terms understood by industry. Specifically, Atmos Energy Corporation suggested that the term "actuation pressure" could be understood by operators to mean either "build-up pressure" or the pressure at which the device is triggered to activate. Additionally, Atmos Energy Corporation emphasized that the phrase "set actuation pressure range" was confusing because operators do not define a device's operating range, but rather select relief devices based on considerations of several factors, including manufacturers' specifications. Atmos Energy Corporation cautioned that requiring operators to set operating pressure ranges would inappropriately shift the obligation to identify and set operating pressure ranges from manufacturers to operators. Williams Companies, Inc., suggested PHMSA define the term "reset actuation pressure" and asked whether the term "reset actuation pressure" meant the nominal reseat pressure, meaning the pressure below the set pressure at which the piston in the valve contacts the seat as the system depressurizes.

Requirements for Design and Configuration of Pressure Relief and Limiting Devices — § 192.199

Two commenters, NAPSR and the City of Sugar Hill, supported proposed § 192.199. Atmos Energy Corporation requested that PHMSA clarify the scope of § 192.199 by limiting it to new or replaced devices and by clearly excluding service regulators with internal relief, service regulators with relief valves installed in customer meter sets, and passive pressure limiting devices, suggesting that operators have already determined the appropriate design and configuration of pressure relief or limiting devices to operate their systems safely and should not be required to perform retrospective analysis on the set points.

National Grid suggested that PHMSA revise § 192.199 to ensure that new or reconfigured relief and limiting devices are designed to activate when needed.

Philadelphia Gas Works, the Industry Trades, and Williams Companies, Inc. asked PHMSA to clarify the applicability of proposed § 192.199, specifically whether it is retroactive. Williams Companies, Inc. asked PHMSA to define or clarify multiple items related to the design and configuration of pressure relief devices. First, Williams Companies, Inc. noted that the phrase "unnecessary releases" in proposed § 192.199(i) is subjective and asked whether an operator is allowed to establish its own criteria for what is acceptable and what is considered unnecessary. The commenter suggested PHMSA provide additional guidance on, or otherwise remove, the phrase. Second, the commenter asked that PHMSA provide guidance in interpreting the term "necessary" in the phrase in the text proposed at § 192.199(i) that states "minimize release volumes beyond what is necessary." Lastly, the commenter noted that the phrase "minimize pressure choking" in proposed § 192.199(i)(2) is undefined and requested PHMSA define the phrase. The Industry Trades suggested that choked flow conditions at the relief valve outlet are often unavoidable and that properly sized relief devices and the associated piping can operate as intended even if flow is choked in the outlet piping. They further suggested that PHMSA should remove "documented engineering analyses" and "pressure choking" in the regulatory language. Atmos Energy Corporation commented that §§ 192.53 and 192.199(f) already address the "pressure choking" compatibility, and suitability requirements of proposed § 192.199(i)(2), rendering it duplicative and recommended its deletion.

The GPTC suggested PHMSA retain existing § 192.199(e) stating that the inclusion of the phrase "to public safety" suggests that § 192.199(e) is only applicable to situations that affect public safety and excludes situations that affect environmental safety. Similarly, Williams Companies, Inc., commented that adding the phrase is not necessary, reasoning that the current wording "without undue hazard" (without the phrase "to public safety") is broad enough to provide PHMSA with the authority to compel an operator to design blowdown piping and pressure relief valves in such a way as to prevent a threat to public safety. In a similar vein, Atmos Energy Corporation argued that the phrase "to public safety" seems redundant insofar as the provision already talks in terms of an "undue hazard," which encompasses hazards to public safety.

The GPTC, KOGA, and Williams Companies, Inc. asked that PHMSA clarify the phrase "otherwise changed" in § 192.199(i). The GPTC indicated that operators routinely swap out relief devices, orifices, or springs. Williams Companies, Inc. expressed concern the phrase was vague and stated that, in the past, PHMSA has interpreted "otherwise changed" to mean "a substantial physical alteration of a pipeline facility as opposed to a repair or restoration." The commenter requested PHMSA clarify whether this remains the agency's interpretation or provide additional clarity. KOGA asked whether a policy of annually rotating (i.e., swapping) relief valves for servicing would count as replacement for the purposes of triggering retroactive design standards. The commenter also requested clarification of whether PHMSA requires vent piping downstream of the outlet of a relief valve be pressure rated.

Enstor Gas LLC suggested that PHMSA include a consideration of engineering design, but not a requirement of a "documented engineering analysis," in proposed § 192.199(e)(i)[395] as requiring a documented engineering analysis would place unnecessary financial burden on operators. Atmos Energy Corporation opposed this proposed provision as ambiguous and without guidance as to how such an engineering analysis might be performed in this context, and cited the limited time, personnel, and financial resources operators have to conduct such analysis

[395] PHMSA did not propose § 192.199(e)(i). PHMSA assumes that the commenter intended to comment on § 192.199(i) and responded to the comment accordingly.

for every replacement of a service regulator. GPA Midstream et al. and New Jersey Natural Gas recommended PHMSA strike proposed § 192.199(i), with GPA Midstream et al. suggesting that the term "documented engineering analysis" was undefined. The commenter further stated that, if PHMSA would like operators to maintain records or documentation for compliance purposes, PHMSA could include language to that effect in the final rule. Oleksa and Associates, Inc. expressed that small businesses might struggle to comply with the requirement. Atmos Energy Corporation and Philadelphia Gas Works expressed concern with PHMSA's use of the adjective "adequate" in proposed § 192.199(i)(1) in describing the level of overpressure protection needed, suggesting that the term failed to set a clear standard of performance and should be deleted.

Williams Companies, Inc., urged PHMSA to reconsider the proposed requirement for operators to install isolation valves in § 192.199(i)(3). The Marcellus Shale Coalition suggested PHMSA remove the words "upstream and downstream" when referring to requiring the installation of isolation valves because it is neither practical nor necessary to require both for the purposes of testing and maintenance. The Industry Trades noted that installing both upstream and downstream valves of a relief valve are not always necessary to facilitate testing or inspection. For example, they noted, operators could test relief valves by closing an upstream valve and using compressed nitrogen to increase pressure in the isolated segment just to the point when the relief valve begins to open. Furthermore, the comment noted that the installation of unnecessary valves increases installation and maintenance costs without a discernible benefit. GPA Midstream Association, et al. expressed concern that the proposed language does not indicate whether downstream pressure safety valves must be installed at the inlet or after the discharge of the relief device. The commenter claimed that installing an isolation valve on the discharge side of a relief valve introduces safety risks associated with inadvertent closures that could block the relief device and suggested PHMSA stipulate that the relief device must be isolatable to facilitate testing and maintenance. Golden Pass Pipeline, LLC stated that proposed § 192.199(i)(3) would be too restrictive and urged PHMSA to consider removing the proposed requirement for "upstream and downstream isolation valves to facilitate testing and maintenance" reasoning that operators are often able to safely test and maintain pressure relief devices without having upstream and downstream isolation valves.

Atmos Energy Corporation requested PHMSA delete proposed § 192.199(e)(i)(2) because it was repetitive and existing §§ 192.53 and 192.199(f) already address the issue. Further, the commenter suggested that proposed § 192.199(e)(i)(3)[396] was repetitive of § 192.199(h), as that latter section already contemplated the presence of valves upstream of the relief and pressure limiting device, and therefore PHMSA should delete § 192.199(e)(i)(3) as well.

Pressure Relief Devices: Inspection and Testing—Proposed § 192.773, Final Rule § 192.739

Williams Companies, Inc, the Industry Trades, and Philadelphia Gas Works suggested that proposed § 192.773 be incorporated into existing § 192.739, since the proposed changes broadened the scope of inspection and testing to include requirements for maintenance and

[396] PHMSA did not propose § 192.199(e)(i)(3). PHMSA assumes that the commenter intended to comment on § 192.199(i)(3) and responded to the comment accordingly.

recordkeeping. KOGA similarly asked PHMSA to clarify whether it considers proposed § 192.773 to be an "independent requirement" because, if not, it would be more efficient for PHMSA to revise §§ 192.739 through 192.743 than to create a new section. KOGA also asked for PHMSA to clarify whether the capacity calculations[397] of § 192.743 would satisfy the requirements of proposed § 192.773, assuming that all expectations are met. Lastly, KOGA urged PHMSA to clarify whether manufacturer specifications for set ranges, springs, components, etc., would satisfy the requirements of proposed § 192.773.

Atmos Energy Corporation suggested PHMSA write proposed § 192.773(a)(2) so that it would read as, "Assess the inlet and outlet piping for piping that restricts the inlet or outlet gas flow, piping that restricts the sensing pressure, and debris," and recommended that the following phrase be struck, "and other restrictions that could impede the operation or restrict the capacity to relieve overpressure condition," as it was repetitive with existing § 192.199(f). According to the commenter, § 192.199(f) already requires that pressure relief or limiting devices, and their associated piping, be designed and configured to prevent impairment, and proposed § 192.773(a) already contemplates this existing requirement. The Industry Trades suggested PHMSA use the verb "evaluate" instead of "assess" for proposed §§ 192.773(a)(1) through (2) with no further explanation.

The Industry Trades and other commenters expressed concern about PHMSA's use of the phrase "documented engineering analysis" because it is vague and subject to differing

[397] Capacity calculation refers to the calculations conducted in accordance with §§ 192.201and 192.743 to determine if pressure relief devices at pressure limiting and pressure regulating stations have sufficient capacity to protect the facilities to which they are connected.

interpretations.[398] New Jersey Natural Gas similarly opposed PHMSA's use of the phrase noting that the proposed requirement eliminated the opportunity for the operator to draw upon their education, training, and experience, as well as minimizing their ability to use the device manufacturer's published technical information. Furthermore, the commenter noted that PHMSA does not define the phrase "documented engineering analysis" which could lead to conflicting interpretations of the requirement. Enstor Gas suggested that for proposed § 192.773(b), PHMSA allow operators to use "operating knowledge and historical documentation" as an alternative to the documented engineering analysis. Atmos Energy Corporation expressed concern that the proposed § 192.773(b) appears to place certain valve manufacturer responsibilities onto pipeline operators and recommended that the proposed § 192.773(b) be deleted in its entirety.

The Industry Trades and multiple operators recommended PHMSA modify the proposed requirement at § 192.773(a)(3)(ii) for operators to complete repairs "as soon as practicable but within 30 days," reasoning that in situations where replacing a pressure relief device is required, it would likely take more than 30 days to redesign the facility, order and receive parts, and install the device; furthermore, they argued that such a timeline is excessively aggressive for a situation that is not jeopardizing public safety. The Industry Trades, Southwest Gas Company, and Great Basin Gas Transmission Company multiple operators recommended PHMSA remove the proposed requirement at § 192.773(a)(3)(ii) to take "continuous action" to stop the further

[398] The American Gas Association (AGA), American Petroleum Institute (API), American Fuel & Petrochemical Manufacturers, American Public Gas Association (APGA), GPA Midstream Association, Interstate Natural Gas Association of America (INGAA), and Northeast Gas Association (PHMSA-2021-0039-26350), August 16, 2023, p. 124.

release of gas, as measures will be taken to "eliminate or minimize the release" but this may take as long as 30 days and having operator personnel onsite for the duration is "not feasible." The commenters explained that it is not always possible for an operator to eliminate or minimize a release quickly, and these releases are not necessarily an immediate threat to people or property. The Industry Trades and other industry commenters noted that this requirement could force operators to shut in the gas supply and curtail service to customers for the duration of repairs, or the amount of time required to acquire a replacement pressure relief device. They reasoned that curtailing service is never a good option for an operator, unless public safety is directly threatened.

The Industry Trades commented that the requirement at § 192.773(a)(3)(ii) to take action when the pressure relief device "allows gas to release to the atmosphere at an operating pressure below the set actuation pressure range" is not always known by the operator and the text should be modified to only hold operators accountable for taking action when they have this knowledge after confirmed discovery.

Furthermore, the Industry Trades expressed a desire for there to be consistent use of the terms "malfunction" and "mis-configuration" in the regulatory context.[399] Specifically, they commented that "mis-configuration" refers to poor design or installation, while "malfunction" suggests a performance issue with the valve or regulator. The commenter requested clarification, because it is important to maintain the distinction between the terms in code requirements.

[399] The word "mis-configuration" was not in proposed § 192.773. See 88 FR 31890 at 31978-31979.

Williams Companies, Inc., asked for clarification on several items related to the proposed pressure relief device provisions throughout § 192.773. First, in § 192.773(a), the commenter asked PHMSA to clarify what "proper function" means, and specifically whether PHMSA would allow operators to establish and document testing, protocols, methods, and metrics in the operator's O&M manual. The commenter also asked if the wording "assess the pilot, springs, seats, pressure gauges, and other components" would require operators to perform an internal inspection, bench testing, or overhaul of a relief device. Third, the commenter asked if the wording "assess the inlet and outlet piping" would require an operator to perform internal inspection of the adjacent piping.

Atmos Energy Corporation opposed proposed § 192.773(b) and requested PHMSA remove it, as the section is duplicative of existing § 192.199(a) through (h) and proposed § 192.199(i), and the commenter believed that proposed § 192.773(b) was already encapsulated in existing written O&M procedure requirements. They reasoned that § 192.199 governs operators' construction, design, use, and maintenance of pressure relief and pressure limiting devices so that these devices function in the intended manner.

NAPSR requested that PHMSA require operators to retain records associated with relief device malfunctions for the lifetime of the pipeline rather than the proposed 5 years in § 192.773(c)(1) because these records could be crucial in an investigation of an incident that has occurred after the 5-year retention period.

3. GPAC Deliberation Summary

Committee discussion of NPRM proposals for pressure relief and limiting device design, configuration, and maintenance began with PHMSA's summary presentation of the proposed regulatory language and its supporting reasoning, including a discussion of its cost and benefits, and an overview of material comments from stakeholders on the proposal, on November 27, 2023. Afterwards, in-person attendees were given the opportunity to share feedback. Among the handful of stakeholders taking this occasion to provide feedback were people representing large transmission pipeline operators, the gas gathering industry, and publicly owned gas distribution utility trade associations. Commenters referenced their written comments and highlighted concerns with the requirement to install upstream and downstream valves, noting that downstream isolation valves may introduce safety risks associated with inadvertently isolating a relief valve. Industry stakeholders commented that PHMSA proposed unclear or subjective language, such as "documented engineering analysis," "beyond what is necessary," "immediate and continuous action," and "pressure choking," and recommended that PHMSA provide clarity on the meaning of these terms. Industry commenters recommended incorporating the proposals at § 192.773 into § 192.739 and adjusting the timeline for repair for relief or pressure sensing equipment to be "as soon as practicable," emphasizing that most operators do not have replacement devices on hand to permit the repair of a relief device within the 30-day period proposed. Commenters representing industry emphasized the different configurations of relief valves that operators use within their facilities and the need to preserve the ability to use "monitor control and full relief"[400] to provide overpressure protection for downstream facilities.

On November 27 and 28, 2023, Committee members discussed their thoughts regarding PHMSA's proposed regulatory language. Committee members representing industry echoed a desire to clarify or eliminate vague language included in the NPRM. Two Committee members representing industry suggested that PHMSA's proposal specifying a requirement for upstream and downstream isolation valves fails to consider the various relief valve configurations operators may use and the methods available to isolate them from the system. A Committee member representing industry suggested that detailed design standards for relief valves already exist in the code and that PHMSA should consider that the ill-defined new requirements are unnecessary. A Committee member representing industry introduced the following proposals for the Committee to consider, which ultimately provided a roadmap for the Committee's discussion: remove the undefined concept of documented engineering analysis; incorporate changes to device maintenance into existing § 192.739; to address malfunctions, operators must take immediate, not continuous action; repairs must occur as soon as practicable rather than the 30 day deadline; remove the requirement for upstream and downstream isolation valves; and pressure choking should not be included in design considerations.

With respect to removing the term "documented engineering analysis," Committee members representing industry expressed that its undefined nature would create uncertainty, while a Committee member representing the public suggested recommending that PHMSA

[400] GPAC Transcript at 82 (Nov. 27, 2023).

create a definition to provide clarity to operators. An industry member expressed concern that each time there was a single new relief valve engineering standards would have to be updated. Committee members representing the public discussed the importance of a documentation requirement for enforcement purposes and to memorialize an important analysis. Some Committee members representing industry and government discussed that, in practice, PHMSA's design and configuration requirement proposals already necessitate a documentation requirement showing compliance with the prescribed engineering standards.

On the topic of adjusting the deadline for addressing a malfunctioning relief valve, Committee members representing the government raised concerns that there may be circumstances, such as environmental permits or clearances, or extreme environmental conditions in parts of the country, which may prevent adherence to a 30- or even 45-day deadline. A Committee member representing industry cited supply chain issues that could have an impact on repair timelines of relief valves. Committee members representing industry emphasized the distinction between response actions to stop a release of methane from a malfunctioning relief valve and the time needed to repair or replace a relief valve, suggesting that lengthier repair timelines would not equate to higher release volumes when an immediate response to stop the release occurred. Committee members representing the government emphasized the importance of having a backstop for the repair timeline to ensure that operators were timely repairing relief valves. There was general acknowledgement among the Committee members that a 30-day repair timeline may not always be practicable, but that repair or replacement should otherwise occur as soon as practicable.

For the proposed requirement regarding the installation of upstream and downstream isolation valves on relief devices, a Committee member representing industry suggested, in line with public comments, that PHMSA should not prescribe specific locations of isolation valves but rather require that operators have the ability to isolate a pressure relief device for testing and maintenance. Although discussion among the Committee members on this topic was limited, there appeared to be general agreement that PHMSA should clarify the relief valve isolation requirements in accordance with the Committee's discussion and recommendation.

The Committee subsequently turned to the topic of removing the requirement for operators to take continuous action when a pressure relief device releases gas below the set pressure range. A Committee member representing the public expressed concern that the removal of "continuous" would imply that an operator would not continue to work on the problem. Committee members representing industry emphasized that an operator would respond immediately to isolate the malfunctioning relief valve from the pipeline infrastructure; however, they opposed requiring personnel to be on-site to continuously to monitor the pipeline until repair, suggesting that in many cases on-site presence may be unnecessary or difficult to maintain until the relief device is repaired. While the Committee members agreed that immediate action was necessary to stop a release of gas from a malfunctioning relief valve, there was further discussion on what continuous actions an operator should be obligated to take before a relief valve was repaired or replaced. A Committee member representing the public requested that PHMSA clarify its proposal related to continuous action to facilitate the discussion among the Committee members. After hearing clarifying remarks from PHMSA, some Committee members representing industry and government acknowledged that overpressure protection must be maintained when a relief valve is taken out of service, but emphasized that continuous, on-site action was not always necessary. An example given was the ability of some operators to monitor and control pipeline facilities from remote locations.

4. GPAC Recommendation

The Committee's recommendations on the design and configuration, and inspection and maintenance of pressure relief devices reflect a 14 to 1 vote among Committee members on how PHMSA should adjust its proposal to navigate the different considerations described above, considering the following:

- PHMSA remove the term "documented engineering analysis" and replace it with the phrase "documentation, including engineering standards" at § 192.199.
- PHMSA remove the phrase "with onsite personnel" from § 192.773(a)(3)(ii).
- PHMSA clarify repair timelines are to be 30 days, unless the repair timeline is impracticable, in which case an operator must complete the repair as soon as practicable.
- With respect to the relief device design requirements proposed in § 192.199, PHMSA remove the proposed requirement for upstream and downstream isolation valves and instead require that operators must have the ability to isolate the relief valve for maintenance and testing.

An underlying thread throughout the Committee's discussion were the themes of practicability and operator flexibility. While not ultimately voted upon by the Committee, members supported moving the proposed requirements § 192.773 to § 192.739.

5. PHMSA Response

General

Regarding PHMSA's use of the terms "set and reset actuation pressure" and "set actuation pressure range" at proposed §§ 192.199(i) and 192.773(a), PHMSA intended the term "set actuation pressure" to refer to the setpoint at which the device activates by beginning to actuate (i.e., open) as intended. The "set actuation pressure range" was intended to reflect the build-up in pressure, above the "set actuation pressure," required to cause the relief valve to completely open and fully relieve pressure at the capacity for which it is designed. Finally, PHMSA intended the "reset actuation pressure" to mean the nominal reseat pressure (i.e., the pressure below the "set actuation pressure" at which the piston in the relief valve contacts the valve seat and closes the relief valve as the system reduces pressure). PHMSA has clarified §§ 192.199(i) and 192.739(c) in this final rule by removing references to those terms and instead referring to either "set pressure" or "reseat pressure" as appropriate. In minimizing releases of gas, operators must consider how the configured set pressure and reseat pressure affect the actual performance of the pressure relief device, including consideration of device tolerances and the build-up of pressure required to cause the relief valve to fully relieve pressure.

PHMSA did not propose a design requirement that required a pressure relief device to have the ability to change its configuration, and therefore, such a requirement in this final rule would be out of scope. In response to a comment that INGAA made, PHMSA agrees that the purpose of a pressure relief device is to prevent the overpressurization of a pipeline; however, while operators can control releases from pressure relief devices, that does not mean that these releases are always planned. Therefore, PHMSA still considers releases from pressure relief devices as sources of unplanned emissions.

PHMSA also heard comments suggesting that certain pressure regulating or pressure limiting stations be exempted from the requirements proposed at §§ 192.199 and 192.773. PHMSA intended the proposed requirements to apply to devices with the capability to release gas to the atmosphere. The suggestion from several commenters to move the requirements proposed at § 192.773 into existing § 192.739, as discussed above in this section, supports the industry's understanding that pressure limiting and pressure regulating stations might also include a pressure relief device which vents or is capable of releasing gas to the atmosphere or to a flare, and that pressure relief devices in such pressure regulating and pressure limiting stations would be covered by these requirements.

In response to the comments PHMSA received regarding PHMSA's use of the phrase "documented engineering analysis," PHMSA is declining to incorporate in this final rule the suggested phrase "consideration of engineering design" and has struck the phrase "documented engineering analysis" from §§ 192.199(i) and 192.739(c) in this final rule. PHMSA agrees with comments and Committee discussion that the term "documented engineering analysis" was unnecessary in the context of relief device designs for minimizing releases of gas. PHMSA's intent was to help ensure that operators demonstrate that replaced, relocated, or otherwise changed relief valves are designed and configured to minimize releases of gas. However, the proposed criteria at § 192.199(i) were developed such that by complying with these requirements, operators' relief valves will as a matter of course be designed to minimize releases of gas to the atmosphere. Additionally, operators already maintain records documenting the design, configuration, and installation of pipeline components, including pressure relief devices, as part of their obligation to demonstrate compliance with the pipeline safety regulations.

Requirements for Design and Configuration of Pressure Relief and Limiting Devices—Section 192.199

In response to a commenter's request for PHMSA to clarify the scope of the proposed amendments to relief device design requirements in § 192.199, this final rule includes an exception for service regulators with internal relief or devices that do not release gas into the atmosphere on a gas distribution system. Compared to pressure relief devices on gas transmission lines, these types of devices are unlikely to result in large releases of gas. Furthermore, the design requirements at § 192.199 are non-retroactive, meaning that operators do not need to analyze or reevaluate existing installations to ensure that their design and configuration minimize unnecessary releases of gas per the new requirements. However, if an existing pressure relief device malfunctions, the malfunction would require an evaluation of the proper functioning of the device and adjustment, repair, or replacements of the malfunctioned device as described at § 192.739(c).

In response to National Grid, the proposed requirement is not intended to impair the proper functioning of a relief device. Neither the final rule nor the NPRM prohibits a release of gas necessary to ensure overpressure protection. The design and maintenance requirements adopted in this final rule address the need to prevent releases from pipelines operating at normal pressures, releases from relief devices that occur at operating pressures below the desired set pressures, and prevent conditions that can cause damage to or impair the function of the relief valve (e.g., choked flow and ice buildup). Section 192.199(f) in this final rule (§ 192.199(i)(3) in the NPRM) addresses design criteria for pressure relief and limiting devices and describes a specific list of factors to address when designing pressure relief or limiting devices and the associated piping.

In response to a commenter's request for PHMSA to clarify what is meant by "minimize pressure choking" at proposed § 192.199(i)(2), PHMSA has removed this phrase from this final rule and incorporated clearer guidance related to minimizing pressure choking at existing § 192.199(f), though the term "choked flow" itself no longer appears in the amendments. This language was intended to address choked flow due to inadequately designed piping. Choked flow occurs when flow is limited through the pressure relief device or associated piping, potentially damaging the valve, or causing the valve to fail to operate as expected. In this final rule, PHMSA is adding at § 192.199(f) the requirement for operators to design and install relief devices to prevent damage to valve, interconnected piping, or other related components. PHMSA's intent is to prescribe device design and installation requirements that prevent conditions like choked flow that could damage the valve during operation.

Section 192.199(i) is intended to help ensure that pressure relief devices and associated piping are designed and configured to minimize unnecessary releases of gas. This final rule language clarifies that an operator's consideration of choked flow also applies to the design of inlet and outlet piping. Additionally, rather than requiring operators to generally attempt to minimize choked flow, this final rule clarifies that the design must be appropriate for the relief device's set and reseat pressures. While commenters correctly noted that the design of relief devices themselves can cause choked flow, poorly designed relief valve piping can cause excessive backpressure on the relief device, which can cause the relief device to oscillate open and close. This oscillation can unnecessarily release gas when a relief device opens prematurely or fails to stay closed, and it can damage the device and cause a failure that can result in a loss of overpressure protection or a large release of gas.

In response to multiple comments requesting clarification as to whether § 192.199(i) would permit an operator to establish their own criteria for what is acceptable and what is considered unnecessary for the design and operation of a pressure relief valve, PHMSA has removed the word "unnecessary" from § 192.199(i) to avoid confusion. An operator must design its overpressure protection equipment to respond adequately to potential overpressure situations. The intent of this provision is for operators to minimize emissions caused by poorly designed or configured pressure relief devices. The use of "minimize" acknowledges that gas will be released from the pipeline facility if a pressure relief valve activates as intended in response to a potential overpressure condition. However, a poorly designed or inappropriately configured relief device may result in the release of more gas than necessary for overpressure protection. Therefore, the use of "minimize" in this provision directs operators to choose appropriately designed pressure relief and limiting devices and configure these devices to minimize releases of gas beyond what is necessary to provide adequate overpressure protection. Implicit in the phrase "beyond what is necessary" at § 192.199(i)(1) is the essential function of relief devices to protect against potential overpressurization, which likely results in the release of gas to the atmosphere. However, against that backdrop, operators must minimize releases that occur beyond that threshold of required protection.

In response to concerns regarding PHMSA inserting the phrase "to public safety" in proposed § 192.199(e), PHMSA has struck that phrase from that section in this final rule. PHMSA did not intend to narrow the interpretation of the regulation; therefore, PHMSA has retained the language at § 192.199(e) as it existed prior to the publication of the NPRM.

In response to concerns regarding PHMSA use of the phrase "otherwise changed" in this section, PHMSA clarifies that a "changed" pressure relief and limiting device can include the installation of a new device or new internal equipment that would affect the operation of the device. This would be the same as how operators implement § 192.13(b), and therefore, PHMSA has struck the phrase "otherwise changed" from § 192.199(i) in this final rule.

In response to the comment concerning the interpretation of "otherwise changed" to mean "substantial physical alteration," as opposed to a pipeline repair or restoration, PHMSA has provided guidance for this term in a previous rulemaking, which is that "otherwise changed" refers to a substantial physical alteration of a pipeline facility as opposed to a repair or restoration.[401]

In response to a query from KOGA regarding annually rotating relief valves, devices that are removed from service for routine maintenance and replaced with identical equipment as part of a regularly scheduled program (i.e., scheduled replacement-in-kind) will not necessarily

[401] PHMSA, "Gas Gathering Line Definition; Alternative Definition for Onshore Lines and New Safety Standards," 71 FR 13289 at p. 13298 (Mar. 15, 2006).

constitute a change or replacement. However, if the replaced device is not identical in design to the original device, then this would constitute a change or replacement. Replacing a device as a means of repair of a malfunction does represent a change or replacement regardless of its design. In response to question regarding whether vent piping must be pressure rated, this rulemaking does not explicitly address this topic besides the requirement at § 192.199(i)(3) for a pressure relief device to include valves necessary to isolate the pressure relief device from the pipeline facility to facilitate testing and maintenance. An operator should develop designs and specifications for vent piping.

In this final rule's pressure relief design requirements at § 192.199, PHMSA is removing the requirement for operators to design relief devices with upstream and downstream isolation valves in accordance with the Committee recommendation and numerous comments received on the issue. PHMSA's intent was to help ensure that operators could inspect, service, and, if necessary, replace pressure relief devices with minimal loss of gas. However, PHMSA was persuaded by comments that a downstream valve is, in most circumstances, not required to accomplish this, since such devices are typically designed to be open to the atmosphere on the outlet side of a closed relief device. Therefore, this final rule instead requires each relief device be designed to include valves necessary to isolate the device to facilitate testing and maintenance. This revised requirement addresses PHMSA's original intent while avoiding costs and potential risks associated with installing potentially unnecessary isolation valves.

In response to comments regarding deleting proposed § 192.199(i)(2) through (3), PHMSA ultimately maintains subparagraphs (i)(2) and (i)(3) in the final rule and makes edits to

§ 192.199(f). Existing § 192.53 addresses materials for pipe and components, but it does not contain specific criteria for the design or general requirements applicable to pressure relief or limiting devices. The requirements in § 192.199 are specific to the design and configuration of pressure relief and limiting devices and are based on information and data on the functioning of these devices that PHMSA has collected. To that end, retaining the requirements in 192.199(i)(2) that the design and configuration of pressure relief or limiting device and associated piping must be appropriate for its operation, compatible with the pipeline commodity, and suitable for its operating environment is necessary and appropriate in order to minimize the release of gas from the device. Therefore, § 192.199(i)(2) provides proper specificity for operators. PHMSA interprets the term "associated piping" to refer to the openings, pipe, and fittings located between the system to be protected and to the atmosphere. Secondly, PHMSA has modified § 192.199(f) in the final rule to clarify that the design of pressure relief and limiting devices should also prevent damage to the valve, interconnected piping, or other related components. Existing § 192.199(f) does not discuss protecting the pipe or the valve. As discussed above in this section, PHMSA merged the additional considerations proposed regarding preventing damage to the valve and associated piping and components to the existing requirement to design relief devices and inlet piping to prevent hammering of the valve in paragraph (f).

Pressure Relief Devices: Inspection and Testing—Proposed § 192.773, Final Rule § 192.739

Based on recommendations from the Committee and from public comments, PHMSA revises the maintenance requirements for pressure relief devices proposed at § 192.773 in this final rule to simplify repair requirements and clarify PHMSA's expectations regarding response actions when pressure relief devices malfunction. These changes are described in greater detail below. Additionally, PHMSA concurs with the comments it received that proposed § 192.773, which included proposed requirements for assessing, repairing, replacing, and reconfiguring pressure relief devices should be merged into existing § 192.739 and has done so in this final rule.

During PHMSA's drafting of revisions to § 192.739 of this final rule, the Agency identified an opportunity to clarify and consolidate each of the scenarios proposed at § 192.773(a)(3) into a description of a malfunction that applies to this section and a set of general response actions operators are expected to take in response to a malfunction. This revision is supported by multiple comments submitted on this proposal related to the described scenarios at proposed § 192.773(a). Accordingly, PHMSA has consolidated these scenarios in a definition of "malfunction" to be used in this section for purposes of identifying when a pressure relief device is not performing as designed or intended and requires operators to provide for safety due to the malfunctioning device, and to evaluate, adjust, repair, or replace the malfunctioning device to restore proper function and overpressure protection. In § 192.739(c) in this final rule, PHMSA is clarifying that a malfunction of a pressure relief device is when any of the following events occur: a pressure relief device activates above its set pressure; a pressure relief device activates above the pressure limits at §§ 192.201(a) or 192.739(b) as applicable; a pressure relief device activates at a pressure below the set pressure; or a pressure relief device otherwise fails to operate as designed or intended. These malfunctions are intended to capture the many ways in which a pressure relief device might not perform as intended or designed, including but not limited to causes related to incorrect operation, mechanical damage, weather-related and outside force damage, manufacturing, or construction related defects, corrosion, and vandalism.[402]

In response to the question regarding the meaning of "proper function," as used at proposed § 192.773(a), PHMSA intends this to mean, as described above, a pressure relief device is performing as designed, set, and intended (e.g., a pressure relief device that releases gas to limit increasing pressure or provide overpressure protection, but does not otherwise release gas to the atmosphere when the pressure in the system it is protecting does not exceed the set pressure). The proper function of a pressure relief device means that it operates without malfunction as is now defined in this final rule at § 192.739(c).

In the paragraphs that follow, PHMSA responds to comments related to the description of malfunctions as they were proposed at § 192.773(a) and now included at § 192.739(c) as described above. In response to a comment from the Industry Trades regarding usage of the word "assess", PHMSA replaces the term "assess" as used at proposed § 192.773(a) to read as "evaluate" at § 192.739 in this final rule, to avoid confusion with the term "assessments" required at § 192.710 and in subpart O.

In response to a concern at proposed § 192.773(a)(1) regarding the wording of "assess the pilot, springs, seats, pressure gauges, and other components," the proposed requirement to assess the pressure relief device components may involve the review of the manufacturer's

[402] PHMSA reminds operators of their obligations regarding failures of equipment, including pressure relief devices, located in HCAs in accordance with subpart O-Gas Transmission Pipeline Integrity Management.

specifications of the device to determine whether there was an issue regarding the device; however, further evaluation may be needed to determine the cause of the malfunction of a device. The NPRM included an assessment of a pressure relief device's ability to properly sense pressure through associated sensing lines connected to the pressure relief device. PHMSA is clarifying that the proposal of proper "sensing" at proposed § 192.773(a)(1) is intended to be included under the evaluation requirements in the final rule at § 192.736(c)(2) for evaluating the proper function of a pressure relief device. PHMSA agrees with commenters that the term "pressure gauges" can be included under the term "other components" and is not necessary to be identified separately; however, the other items described, namely springs, pilots, and seats are common sources of equipment failure as identified by operator incident reports and warrant specific mention. Therefore, PHMSA declines to remove these items at § 192.739(c)(2) in the final rule.

Regarding the concern related to the phrase "assess the inlet and outlet piping" in § 192.773(a)(2), this provision requires evaluating the piping to identify any possible restrictions to the flow of gas both in and out of the relief device. It may be necessary for an operator to conduct an inspection of the inside of this piping to identify a restriction in flow that might have caused the malfunction. In response to a request to strike the phrase "other restrictions that could impede the operation or restrict the capacity to relieve overpressure conditions" from proposed § 192.773(a)(2), PHMSA revises the proposed requirement at § 192.739(c)(3) in this final rule to provide clarity and reduce confusion. In response to the comments that suggested this text is duplicative of the design requirement at § 192.199(f), the requirements at § 192.739 are maintenance requirements intended to help ensure that relief devices that malfunction are properly maintained, repaired, and restored to operate as designed. In the event of a malfunction, the requirements at § 192.739 include an evaluation of several aspects of relief valve functioning to facilitate adjustment, repair, or replacement of relief devices.

In response to whether the requirements at § 192.743 for the required capacity calculations for pressure relief devices, pressure limiting stations, and pressure regulating stations would satisfy the requirements of proposed § 192.773, the proposed requirements for operators to review the configuration of pressure relief devices at § 192.773 did not explicitly include the review of the capacity calculations found in § 192.743. However, a review and confirmation of the capacity of the malfunctioned relief device was intended by the proposed requirement for an operator to assess the proper function of pressure limiting or relief devices. To the extent that incorrect capacity calculations or inadequate capacity of a relief device contributes to the malfunction of a relief device, PHMSA would expect an operator to perform further and necessary evaluation to determine the cause of the malfunction, including, but not limited to, reviewing relief device capacity calculations, and making any necessary corrections to the calculations or replacing the relief device. PHMSA also recognizes that, in response to becoming aware of a malfunctioning pressure relief device, operator response typically includes as a best practice, ad hoc inspections and tests in accordance with § 192.739(a) and review of capacity calculations in accordance with § 192.743. Accordingly, PHMSA is adding new § 192.739(c)(4) to include an explicit requirement for operators to evaluate relief device capacity in accordance with existing § 192.743.

In response to a comment from the Industry Trades regarding the possibility that an operator might not be aware of a malfunction of a pressure relief device (e.g., activates at a pressure below the set pressure), PHMSA recognizes that this is a common scenario experienced by operators. Pressure relief devices might be identified as having malfunctioned through various means, including but not limited to, noise or odor complaints from the public, pipeline leakage surveys, pipeline patrols, and the annual inspections and tests required at § 192.739(a). PHMSA also recognizes that, in response to becoming aware of a malfunctioning pressure relief device, operator response typically includes as a best practice, an ad hoc inspection and test in accordance with existing § 192.739(a) and review of capacity calculations in accordance with § 192.743. In merging the proposed requirements at § 192.773 into § 192.739, PHMSA also intends to reduce duplicative requirements and improve clarity. Accordingly, PHMSA includes a requirement at § 192.739(c)(5) in this final rule that an operator conduct the inspections and tests required by paragraph (a) of this section when the operator discovers the malfunction of a pressure relief device that was not discovered during the inspections and tests required by paragraph (a) of this section. PHMSA expects that operators will be able to leverage existing O&M procedures for the tests and inspections required by existing § 192.739(a) as part of complying with the new requirements being finalized at § 192.739(c) and (d).

In response to concerns regarding the terms, "malfunction" and "mis-configuration," PHMSA has defined the term "malfunction" in this final rule at § 192.739(c) as described above. The NPRM did not use the term "mis-configuration" and the term is not in this final rule. To the extent that a "mis-configuration" is meant to be, or is part of, a malfunction as defined at

§ 192.739(c), an operator must address this in their O&M procedures for complying with § 192.739(c). PHMSA expects operators with malfunctioning pressure relief devices to take the required steps in § 192.739(c)(1) through (5), and if the operator determines, based on the inspections, tests, and evaluations of the malfunctioned pressure relief device, that an adjustment to the device, such as resetting the set pressure in accordance with the manufacturer's specifications, or adjusting the set pressure restores proper function and does not otherwise require repair or replacement under this section, then the operator has complied with this section. However, PHMSA expects that operators will use their best judgement to repair or replace relief devices that frequently require adjustments due to malfunctions or equipment failures. Accordingly, at § 192.739(c)(6) in this final rule, PHMSA recognizes that some malfunctions of pressure relief devices might be corrected by adjustment, as opposed to repair or replacement, and is therefore allowing operators the option to adjust a malfunctioned pressure relief valve, in accordance with the operator's O&M procedures and the pressure relief device manufacturer's instructions and specifications, to restore proper function to the pressure relief device.

In response to concerns on whether manufacturer specifications for set ranges, springs, components, etc., would satisfy the requirements of proposed § 192.773, the requirement at § 192.739(c) is to evaluate the proper function of pressure relief devices. A malfunction, as defined for this section, indicates that the relief device is no longer functioning reliably as designed, set, or intended. The requirements at § 192.739(c) are intended to identify the cause of the malfunction, which might not be resolved by the manufacturer's specifications alone. Malfunctions of these devices occur for a variety of reasons beyond what is contained in the manufacturer specifications for such a device. To the extent that a relief device functions without further malfunction after being evaluated and adjusted (i.e., restored to manufacturer specifications as suggested by the commenter) in accordance with this section, then doing so would satisfy the expectations for adjustment in § 192.739(c)(6). If the adjustments fail to remedy the malfunction as defined in paragraph (c), then further repair or replacement may be required, or it may indicate a deficiency in the design of the relief device assembly.

Regarding the timelines proposed for repair or replacement in the NPRM at § 192.773(a)(3), PHMSA is simplifying the required repair timeline from either "immediate" in the case of a relief valve that activates above its set pressure and its pressure limits or otherwise fails to operate or provide overpressure protection, or "as soon as practicable but within 30 days" in the case of a relief valve that allows gas to release to the atmosphere at a pressure below the set pressure, to "as soon as practicable" in a new § 192.739(c)(6). PHMSA was persuaded by the comments received and Committee discussion that various factors out of the control of the operator, including weather and supply chain restraints, may prevent operators from meeting the 30-day repair timeline in most cases. Additionally, PHMSA agrees that the intent of the revisions to § 192.739 is to help ensure safety and minimize emissions caused by malfunctioning relief devices, and that requiring an immediate response to stop the release and provide for pressure control and overpressure protection meets that intent without prescribing unnecessarily short repair timelines. PHMSA considered the Committee's recommendation that PHMSA require a 30-day repair timeline unless impracticable, then otherwise as soon as practicable. However, in view of the committee discussion that 30 days was likely always impracticable, and the

Committee's failure to put forward a prescriptive timeline that may be practicable, PHMSA determined that a repair timeline of "as soon as practicable" is a more accurate reflection of what will occur in practice. Though the final rule does not adopt a prescriptive repair timeline, requiring an immediate response to the malfunctioning release valves pending repair provides both safety and environmental protection until the device is repaired or replaced. This change therefore addresses immediate risks to public safety and the environment, while providing flexibility to repair the malfunctioning relief valve based on the unique circumstances and geography of individual operators.

PHMSA is also making revisions in the final rule to address concerns from public comments and the Committee regarding the requirement to take "immediate and continuous action with on-site personnel" to stop a release caused by a relief device malfunction. Specifically, the final rule clarifies at § 192.739(c)(1), as a general requirement in response to any malfunction of a pressure relief device, that an operator is required to take immediate action to stop the release caused by the malfunction and to restore overpressure protection. Operators are also required, in response to any malfunction of a pressure relief device, to maintain alternative methods of overpressure protection in the interim until the pressure relief device is adjusted, repaired, or replaced. The final rule also simplifies and clarifies at § 192.739(a)(6) the requirement to conduct any adjustment, repair, or replacement as soon as practicable.

Additionally, reference to the term "on-site personnel" proposed at § 192.773(a)(3)(ii) as it relates to responding to a malfunctioned pressure relief device has been removed in the final rule. PHMSA was persuaded by the comments received and Committee discussion that not all responses to malfunctioning pressure relief devices requires on-site personnel to be in continuous attendance, and that many required actions can be performed from remote locations with the same efficacy and level of safety. PHMSA intended that operators respond immediately to pressure relief device malfunctions to stop the release and continuously provide pressure control and alternative methods of overpressure protection until the malfunctioning device is restored. The revisions PHMSA made in this final rule emphasize those requirements while providing flexibility to operators in methods of maintaining pressure, evaluating the malfunction, and adjusting, repairing, or repairing the pressure relief device without requiring personnel on-site during the evaluation and repair period. PHMSA acknowledges that the proposed language, "immediate and continuous action with on-site personnel" implied that personnel would be required to stay on-site even after the release has ended and overpressure protection has been restored. These revisions discussed above address the uncertainty described in public comments and avoid costs from unnecessary compliance activities.

Regarding the Committee's recommendation to replace the phrase, "as demonstrated by a documented engineering analysis" at proposed § 192.773(b) to simply refer to documentation, including engineering standards, PHMSA evaluated the proposed requirement as it would apply in § 192.739.[403] This proposed requirement was intended to oblige operators to have procedures for ensuring existing relief devices are configured (i.e., set) to help ensure the minimization of

[403] As previously discussed, PHMSA agreed with the comments it received that proposed § 192.773, which proposed requirements for the assessment of the proper function of pressure relief devices, should be merged into existing § 192.739 and has done so in this final rule. In the final rule, the proposed § 192.773 requirements are now in paragraph (c) and (d) at § 192.739.

release volumes while providing adequate overpressure protection. For the reasons discussed above in this section, PHMSA has removed the phrase "documented engineering analysis" from the final rule. For existing devices, PHMSA finds that this requirement, as proposed at § 192.773(b) and applicable to existing relief devices, is unnecessary. PHMSA determined that, to the extent that an existing relief device malfunctions and is found by the operator to require adjustment, repair, or replacement, a new relief valve will be subject to the requirement to be configured to minimize releases of gas in accordance with the requirements at § 192.199. Existing relief valves requiring adjustment or repair will have been evaluated, in accordance with paragraphs (c)(2) through (c)(4) of this section and tested and inspection in accordance with paragraph (c)(5) of this section, and then adjusted or repaired to return the relief valve to function as it was designed (i.e., in accordance with § 192.199), otherwise such a device would require replacement.

In response to comments on the recordkeeping requirements, PHMSA has simplified the proposed record retention timelines at § 192.739(d) to a single requirement to maintain records of pressure relief device malfunctions and records pertaining to adjustment, repair, or replacement for the life of the device. This extends the retention period for records of relief device malfunctions (5 years was proposed) and shortens the retention period for records related to the repair (life of the pipeline was proposed). In totality, these include records of pressure relief device malfunctions and records pertaining to pressure relief device repair, replacement, and adjustment for the life of the device. Operators now must maintain records of malfunctions documenting the performance history for the life of the relief device, but an operator may discard repair records after the device has been taken out of service and such records are no longer relevant to the performance of the device in question. Records of pressure relief device malfunctions that occur in HCAs are subject to the gas transmission pipeline integrity management recordkeeping requirements at § 192.947. Information on past malfunctions can help operators manage the integrity and reliability of pressure relief devices on their systems. If an operator can identify a potential issue with a particular style of device or the manufacturer of the component, this would be useful for identifying potential threats to the integrity of their pipeline due to similar failures on similar devices. If operators discard records of malfunctions after 5 years, it will be harder to ascertain if there is a long-term or systematic issue with the performance of a relief device design or configuration. Finally, as NAPSR commented, if there was an incident related to a pressure relief device, information on relief devices with similar failures would be useful for operators to have as a part of an investigation.

Consistent with changes PHMSA is finalizing at § 192.739(c)(6) to provide operators the option to adjust a malfunctioned pressure relief valve, PHMSA clarifies that the term "reconfiguration" used in proposed § 192.773(c)(2) is being replaced with "adjustment" in the final rule § 192.739(d). "Reconfiguration" implies that redesign may be required, which is outside of the scope of the repair requirements envisioned under this section. Additionally, PHMSA elects to remove "including any engineering analyses" from the recordkeeping requirements at § 192.739(c) in the final rule for evaluating, testing, and inspecting pressure relief devices that have malfunctioned. PHMSA finds that by integrating the requirements proposed at § 192.773 into existing § 192.739, it is no longer necessary to include the specific language recommended by the Committee as the records required, directly and indirectly through § 192.739(c), are comprehensive, and include an evaluation of engineering analyses in the case of capacity calculations and verification of pressure relief device and piping design information.

In the RIA, PHMSA evaluated relief devices as part of the general analysis on detecting and repairing leaks. The benefits from the improved design, configuration, and maintenance will yield dividends for the environment and public safety due to reduced emissions.[404]

O. Investigation of Failures—§ 192.617

1. Summary of PHMSA's Proposal

Understanding the causes of pipeline leaks and reasons for malfunction of pressure relief devices is essential for identifying systemic threats to pipeline integrity and preventing similar failures in the future. Section 192.617 requires operators of gas distribution, transmission, offshore gathering, and Type A gathering pipelines to have procedures for analyzing the causes of "failures and incidents." When referring to "failures," the instructions for PHMSA's gas transmission and regulated gas gathering annual report reference ASME B31.8S ("Managing System Integrity of Gas Pipelines") and its definition of failure. ASME B31.8S is incorporated by reference in the gas transmission IM regulations in subpart O to part 192, which similarly includes requirements to assess the history of failures and consider the likelihood of failures in the operator's IM program. However, PHMSA has not previously defined the term "failure" as

[404] As noted in the RIA, EPA estimated emissions from gas transmission venting blowdowns at 133,761 metric tons of methane in 2022. Both governmental programs, such as EPA's Methane Challenge program, and commitments from private operators have taken voluntary efforts to reduce methane emissions. This final rule will further reduce methane emissions.

used in § 192.617. To address potential confusion regarding the definition of "failure" and whether a leak requires investigation as a "failure" under § 192.617, PHMSA proposed in the NPRM to revise § 192.617 to define the term "failure" for the purposes of § 192.617 using language similar to the language for "failure" found in ASME B31.8S. PHMSA further clarified in the NPRM preamble that, for gas pipelines that are subject to § 192.617, all leaks would require investigation as "failures" under that section.

2. Summary of Public Comments

Several commenters supported PHMSA's proposed clarification of "failure" in § 192.617. Williams Companies, Inc. noted that a new definition would help minimize subjectivity in failure investigations, and in particular supported PHMSA's utilization of existing ASME/ANSI B31.8S definitions. The PST suggested that PHMSA adopt the proposed definition of "failure" and further expand its applicability to include Types B, C, and R gathering lines. On the other hand, some operators supported applying the definition to transmission lines and Type A gathering lines but opposed applying the definition to distribution lines or expanding failure investigation requirements to Type B or Type C gathering lines.

NAPSR suggested that PHMSA remove the proposed "failure" definition in § 192.617(e) and further review the criteria for requiring a failure investigation, arguing that a failure investigation was not warranted or necessary for routine situations where the cause of the failure is clear (such as outside force damage), but a failure investigation should be required for larger more serious incidents. NAPSR also observed that, in the absence of a regulatory definition, many operators have developed their own criteria to determine exactly what "failures" trigger investigation under § 192.617, while others have left such determinations to management discretion.

Several trade associations, including Industry Trades and AGA, Energy Association of Pennsylvania, Florida Natural Gas Association, et al., and multiple individual operators opposed PHMSA's proposal that all leaks should be considered failures requiring a full failure investigation. Therefore, commenters recommended that PHMSA revise the proposed definition to mirror the definition in ASME/ANSI B31.S, which operators are familiar with, and that PHMSA should not consider all leaks to be "failures." The Industry Trades noted that in PHMSA's existing instructions for the gas transmission and gathering annual report form (PHMSA form F 7100.2-1), which reference the definition in ASME B31.8, failure is defined "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 completely inoperable." They commented that, under the industry standard definition, individual leaks generally would not constitute "failures" because they do not render a pipeline "completely inoperable" or "incapable of satisfactorily performing its intended function", nor do leaks demonstrate that a pipeline has "deteriorated seriously to the point that it has become unreliable or unsafe for continued use." New Jersey Natural Gas and others expressed concern that a failure investigation for every leak would have an "enormous impact" on operator resources and would be highly impracticable for operators to implement. Multiple operators suggested that PHMSA's definition of "failure" should be focused on safety issues, property damage, and integrity risks. Operators such as INGAA and Kinder Morgan, Inc. suggested that PHMSA narrow the definition of "failure" to exclude intentional releases and leaks that can be resolved through routine maintenance, since the causes of these releases are already well understood and thus failure investigations would have little benefit. Kinder Morgan suggested that no leaks other than grade 1 leaks present a hazard sufficient to trigger a failure investigation. The New York State Department of Public Service suggested that PHMSA clarify the definition of "failure" to exclude leaks that do not result in a reportable incident as defined in § 191.3. An individual commenter and Enstor Gas, LLC said that PHMSA's proposed definition of "failure" would be misleading to the general public, because a pipeline becoming inoperable is not a "failure" within the ordinary meaning of that term.

The GPTC suggested PHMSA move the definition of "failure" to § 192.3 and provide additional clarity. However, Industry Trades, INGAA, and multiple operators opposed PHMSA including the definition of "failure" in § 192.3 arguing that PHMSA has not evaluated the impacts of using such a definition throughout part 192.

3. GPAC Deliberation Summary

GPAC discussion of NPRM proposals relative to the failure definition in § 192.617 and other miscellaneous topics occurred on March 27, 2024. PHMSA summarized the current regulations on failure investigations and explained the proposed definition of failure and its applicability to the entirety of part 192. PHMSA also provided an overview of comments from stakeholders on the proposal. The GPAC then provided opportunities for members of the public present at the meeting to present their feedback. Among the stakeholders who provided feedback were operators. Several of the commenters highlighted concerns from the written comments that the proposed failure definition was so broad that it would result in unnecessary and onerous investigations. Some of the commenters reiterated written comments that the definition of failure should match the definition provided in ASME B31.8S.

GPAC members then discussed PHMSA's proposed regulatory language. Several industry members reiterated concerns regarding how the proposed definition would result in investigations for all leaks, which would not be as beneficial as focusing on significant incidents. Several public representatives were supportive of proposed failure definition, with one public representative reiterating a comment that the proposed definition and investigation requirement should be expanded to include other types of gathering lines. One industry member acknowledged the flexibility of the language, while also noting that the preexisting language at § 192.617 applies to detailed failure investigations which include laboratory analysis. Further, this industry member acknowledged the potential for reasonability of the definition, while also noting that the proposal would change the way section is currently interpreted and applied.

4. GPAC Recommendation

The GPAC did not provide a specific recommendation on the proposals at § 192.617.

5. PHMSA Response

PHMSA appreciates commenters' observations about the implications of differences between PHMSA's proposed definition of "failure" in the NPRM and the definition of "failure" in ASME B31.8S. As discussed in the NPRM, PHMSA's efforts to define this term are primarily targeted at providing clarity to operators on compliance with § 192.617 in order to facilitate operator understanding of systemic threats to pipeline integrity. Therefore, PHMSA does not agree with commenters that adding the failure definition to § 192.3 would broaden its applicability. Further, PHMSA does not agree with the handful of commenters (contradicted by many others) that argued against including any definition at all since operators may have developed their own criteria or exercise discretion in determining exactly what "failures" trigger investigation under § 192.617. PHMSA is seeking to minimize such subjectivity and ad hoc decision-making, and PHMSA agrees with commenters that a definition consistent with ASME/ANSI B31.8S can be most readily implemented by operators, since operators should already be familiar with this industry standard and PHMSA annual report instructions already reference this definition. Although some commenters specify that the public may be confused by the usage and definition of the term "failure," the application of the term will be used and implemented by industry. PHMSA acknowledges the concerns raised by commenters that classifying all leaking pipes as failures could force operators to perform unnecessary investigations where the root cause of the leak is obvious.

Therefore, PHMSA is revising the pipeline safety regulations to incorporate a definition of "failure" in this final rule to be consistent with ASME B31.8S. This action is consistent with PHMSA's position on the definition of "failure" recently set forth in PHMSA's Valve Rule FAQ Batch 1,[405] which was issued on October 13, 2023. In this final rule, PHMSA specifies that a "failure" is "an event in which any portion of a pipeline becomes completely inoperable, is

[405] Valve Rule FAQs Batch 1 (October 25, 2023) at page 3, available at: https://www.phmsa.dot.gov/technical-resources/pipeline/valve-rule/valve-rule-faqs-batch-1. In FAQ #5, PHMSA specifies its use of the ASME B31.8S definition of "failure" in the context of the requirements operators are to follow at § 192.617.

incapable of satisfactorily performing its intended function, or has deteriorated seriously to the point that it has become unreliable or unsafe for continued use." Under this definition, a pipeline facility with an identified leak is not necessarily a "failure" that requires an investigation per § 192.617, if it is mitigated before it becomes unsafe.

PHMSA acknowledges the concerns raised by commenters that the proposed definition of "failure" could result in operators being required to classify leaking pipes as failures and agrees that there could be other contributing factors that result in a leaking pipe. Applying the ASME B31.8S definition makes clear that a pipeline facility that leaks is not necessarily a "failure" that requires an investigation per § 192.617.

PHMSA did not propose to apply all failure investigation requirements in § 192.617 to Types B, C, and R gathering pipelines in the NPRM, and PHMSA declines to adopt such a change in scope at this final rule stage. PHMSA appreciates comments from stakeholders in support of such an expansion of failure investigation requirements, and PHMSA may consider further revisions to failure investigation requirements in the future.

PHMSA agrees with commenters suggesting that the definition of "failure" should be limited to § 192.617, as originally proposed, and that the definition should not be moved to § 192.3 or otherwise made applicable to the entirety of part 192. PHMSA appreciates comments on the value of a more broadly-applicable definition of "failure," and in the future PHMSA may consider addressing the other uses of the term "failure" throughout part 192. Based on the analysis in the final RIA, the adopted failure definition in § 192.617 of this final rule does not result in principal changes to the leak detection and repair requirements for pipelines.

P. Requirements for Regulated Gas Gathering Pipelines—§ 192.9

1. Summary of PHMSA's Proposal

The requirements in part 192 applicable to offshore and Type A, Type B, and Type C regulated onshore gas gathering lines are defined in § 192.9.[406] In the NPRM, PHMSA proposed to require operators of Type A, Type B, Type C, and offshore regulated gas gathering lines to comply, with some exceptions, with the requirements in the NPRM applicable to gas transmission lines. PHMSA also proposed to apply the revised reporting requirements described in section III.L to these gathering lines, specifically the amendments to the annual report forms to improve the collection of information about leaks and repairs and the new large-volume gas release report requirements.

Historically, non-rural gathering lines were subject to the requirements applicable to gas transmission line. In 2006, PHMA published a final rule replacing the "rural" and "non-rural" gathering line definitions established in the original pipeline safety regulations with offshore,[407] Type A,[408] and Type B[409] classification based on class location and pressure. While Type B gathering lines were subject to a narrower set of requirements under part 192 due to the lower public safety risk, Type A gas gathering lines and offshore gas gathering lines remained subject

[406] Since the publication of the NPRM, a final rule titled "Pipeline Safety: Requirement of Valve Installation and Minimum Rupture Detection Standards: Technical Corrections" was published on August 1, 2024 (88 FR 50056) which made changes to § 192.9 that did not appear in the NPRM.

[407] Except as provided in § 192.1(b), any gas gathering line located offshore as that term is defined in § 192.3.

[408] Gas gathering lines in class 2, class 3, or class 4 locations that are metallic with an MAOP producing a hoop stress of 20 percent or more of SMYS, or non-metallic with an MAOP more than 125 psig, see § 192.8(c)(2).

[409] Metallic and the MAOP produces a hoop stress of less than 20 percent of SMYS. In class 3, class 4, and certain class 2 locations.

to the requirements applicable to gas transmission pipelines, with limited exceptions listed in § 192.9(c) and (b), respectively. Type A gas gathering lines are defined in § 192.8(c)(2) as gathering lines in Class 2, Class 3, or Class 4 locations that are metallic with an MAOP producing a hoop stress of 20 percent or more of SMYS, or non-metallic with an MAOP more than 125 psig. In other words, a Type A gathering line is located in a populated area, defined as a class location unit containing 10 or more buildings intended for human occupancy (Class 2 or Class 3) or where buildings with 4 or more stories are prevalent (Class 4) and that operates at relatively high pressure. Type B lines are similarly located in more densely populated Class 2, Class 3, and Class 4 locations, but operate at lower pressure. In a final rule published November 15, 2021, PHMSA defined Type C regulated gas gathering lines, which applied a subset of part 192 requirements (similar to Type B lines) to gathering lines in Class 1 location with an outside diameter of 8.625 inches or greater with an MAOP (or maximum operating pressure) producing a hoop stress of 20 percent or more of SMYS, or non-metallic with an MAOP more than 125 psig.[410]

For Type A gas gathering lines, PHMSA proposed no new exceptions to § 192.9, and therefore the requirements in the NPRM applicable to gas transmission lines would apply to Type A gas gathering lines. Offshore gathering lines are treated similarly in part 192, and the amendments proposed in the NPRM for gas transmission lines would also have fully applied to offshore gas gathering lines with the exception of certain requirements for operators of these

[410] 86 FR 63295, "Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments" (Nov. 15, 2021).

pipelines to use leak detection equipment and comply with leak detection performance standards for leakage surveys of offshore pipelines submerged below the waterline. The proposal to apply the requirements in the NPRM to Type A gathering lines was described in the NPRM and evaluated in the PRIA.

The proposed requirements applicable to Type A and offshore gathering lines included revised definitions (§ 192.3); engineering analyses for the design of pressure relief devices (§ 192.199); modified initial testing requirements to account for environmental hazards (§§ 192.503, 192.507, 192.509, and 192.513); modified procedural manual requirements to provide for eliminating leaks and minimizing releases of gas as well as remediating or replacing pipelines known to leak (§ 192.605); revised failure investigation procedure requirements for the investigation of leaks (§ 192.617); enhanced patrolling requirements (§ 192.705); enhanced leakage survey requirements (§ 192.706); new leak grading, repair, and documentation requirements (§§ 192.703(c) and (d), 192.709, 192.760 and 192.763); new limitations on uprating pipelines (§§ 192.553 and 192.557); new leak detection personnel qualification requirements (§ 192.769); specific requirements for minimizing blowdown emissions (§ 192.770), and new pressure relief device maintenance requirements (proposed § 192.773, now § 192.739). Additionally, the revisions to the part 191 reporting requirements described in section III.L would apply to Type A gathering Lines.

Type B and Type C gathering lines are required to comply with certain reporting requirements in part 191 and the specific requirements listed for those pipelines in §§ 192.9(d) and (e), respectively. Previously, operators of all Type B gathering lines and certain Type C gathering lines were required to perform leakage surveys in accordance with § 192.706, using leak detection equipment and promptly repair hazardous leaks in accordance with § 192.703(c). Existing § 192.9(f) includes an exception from the previous requirement for operators to perform leakage surveys and repair hazardous leaks on Type C gathering lines that are 16 inches or less in outside diameter that are not located near structures.[411] For both Type B and Type C regulated gas gathering lines, PHMSA proposed to apply the requirements in the NPRM applicable to gas transmission lines for leakage surveys (§ 192.706), leak grading and repair (192.760), and the ALDP performance standard (§ 192.763). For Type C gathering lines, PHMSA also proposed to remove the existing exception in § 192.9(f) for operators to perform leakage surveys and repairs on certain type C gathering lines, which would subject all Type C gathering lines to those requirements. In addition to proposing operators comply with these leakage survey requirements, PHMSA also proposed to require operators of Type B and Type C gathering lines to comply with visual right of way patrol requirements applicable to gas transmission lines at of § 192.705 (see section III.B for the discussion of changes to gas transmission line patrol requirements). The NPRM also proposed to require operators of Type B and Type C gathering lines to comply with the requirements for the design of new, replaced, relocated, or otherwise changed pressure relief and limiting devices and the requirements for maintaining pressure limiting and regulating stations that were proposed in § 192.773, which this final rule has merged into § 192.739 (see

[411] Per § 192.9(f)(1), if the pipeline is not located within either a potential impact circle or class location unit containing a building intended for human occupancy or other impacted site as defined in paragraph (f)(3).

section III.N for the discussion of requirements for the design and maintenance of pressure relief devices).

PHMSA proposed additional requirements in the NPRM for Type B and Type C gathering lines to address safety and enforcement gaps for such lines and clarify the scope of section 114 of the PIPES Act of 2020. Specifically, PHMSA proposed to require operators of both Type B and Type C gathering lines to have and follow a manual of written O&M procedures in accordance with § 192.605. Combined with the amendments to § 192.605 described in section III.F, this proposed to codify a self-executing mandate in the PIPES Act of 2020 that requires all pipeline operators' plan to contribute to public safety and protection of the environment, eliminate hazardous leaks, minimize releases of natural gas, and replace or remediate pipelines known to leak based on their material, design, or past operating and maintenance history. Additionally, the NPRM proposed to require operators of Type B gathering lines to develop and implement emergency plans in accordance with § 192.615, which is currently required for all other regulated onshore gas gathering lines.

Finally, PHMSA proposed new and revised reporting requirements for gas gathering lines. PHMSA proposed to require operators of regulated onshore gas gathering lines (Type A, Type B, and Type C gathering lines) to participate in the NPMS requirements in accordance with § 191.29. As discussed in section III.L, PHMSA also proposed to apply the new large-volume gas release report to all gas gathering lines, including Type R gathering lines that are currently subject only to reporting requirements. Finally, the amendments to annual reports described in section III.L also apply to Type A, Type B, Type C, and offshore gas gathering lines. PHMSA did not propose changes to the annual report form for Type R gathering lines.

2. Summary of Public Comments

Scope and General Authority

The PST said that, despite Type C and R gathering line classifications not existing prior to the promulgation of the PIPES Act of 2020, PHMSA has clear authority to regulate all types of gathering lines under the PIPES Act of 2020 and its general authority to prescribe safety standards for pipeline facilities. The MD Attorney General et al. said the proposed changes to patrolling and surveying requirements for Type B and C and offshore gas gathering pipelines were consistent with section 113 of the PIPES Act of 2020. Similarly, the Joint Environmental comment supported applicability for regulated gas gathering lines and submitted supplementary materials in appendix B of their comment summarizing emissions studies performed with aerial methane monitoring surveys in the Permian Basin[412] and results from other production Basins in Colorado, Pennsylvania, and California.[413]

The LA Attorney General et al. opposed PHMSA including offshore lines in proposed § 192.9, commenting that regulating leaks from offshore gathering lines is not appropriate because methane released from subsea pipelines rarely reaches the surface. The PST requested PHMSA clarify that section 114 applies to Type B and Type C gathering lines. GPA Midstream

[412] Yu et al., "Methane Emissions from Natural Gas Gathering Pipelines in the Permian Basin," Environ. Sci. Technol. Lett. (Nov. 8, 2022).

[413] Cusworth, Daniel et al. "Strong Methane Point Sources Contribute a Disproportionate Fraction of Total Emissions Across Multiple Basins in the United States." 119 PNAS, No 38, (Sept. 13, 2022).

Association and API argued that sections 113 and 114 of the PIPES Act of 2020 only apply to operators of regulated onshore gas gathering lines in Class 2, Class 3, and Class 4 locations (i.e., Type A and Type B), but not to Type C and offshore gathering lines in Class 1 locations. The Marcellus Shale Coalition suggested that PHMSA should exempt Type C gathering lines from the gas transmission line patrol and leakage survey requirements in §§ 192.705 and 192.706, respectively.

Regarding the scope of the NPRM, the PST supported the proposed expanded applicability of pipeline safety provisions to Type B and Type C gathering pipelines, reasoning that those pipelines are not currently subject to many critical safety requirements. The PST added that this expansion of applicability helped ensure section 114 of the PIPES Act of 2020 would be fully implemented. The MD Attorney General et al. said that the proposed changes to the applicability of pipeline safety provisions for Type B and Type C gathering pipelines would fill a major regulatory gap that has created environmental and public safety risks, concluding that the proposals are consistent with section 113 of the PIPES Act of 2020.

Senator Cruz, et al., multiple industry trade organizations, and several operators said that Class 2, Class 3, and Class 4 locations are subject to the leak detection requirements created under sections 113 of the PIPES Act of 2020, but that Class 1 locations and offshore gas gathering lines are not. Industry trade associations stated that the NPRM proposed requirements beyond PHMSA's mandate under section 113, particularly for Type C pipelines in Class 1 locations. GPA Midstream, et al., API, and several operators stated that PHMSA's assertion that section 114 of the PIPES Act contained a "self-executing mandate" that applies to regulated

Type C gathering lines was incorrect as a matter of law. GPTC stated that PHMSA did not provide a reasonable basis for the proposed revisions to Type B and Type C gathering lines and suggested that PHMSA remove the requirements for Type B and Type C gathering lines from the final rule and clarify why the "discretionary authority" granted to PHMSA is now exercised through the NPRM.

Industry Trades; GPA Midstream Association, et al.; TPA; Texas Chemical Council; and an operator said that the preliminary risk assessment for the proposed regulations for Type C gathering lines failed to satisfy the requirements of the PIPES Act of 2020 and the Pipeline Safety Act under 49 U.S.C. 60102(b)(3) by not considering other non-regulatory options for regulated gathering lines, especially Type C gathering lines. Commenters representing the gathering pipeline industry further commented that the preliminary risk analysis did not include adequate technical data or demonstrate that the benefits of the proposed requirements justify the costs. Arkansas Independent Producers and Royalty Owners similarly opposed PHMSA promulgating any standards for Type C gathering lines and suggested PHMSA withdraw other proposed gathering line provisions due to claimed deficiencies in the risk assessment regarding unit costs, costs and benefits for patrols, and the choice of emissions factor for Type B and Type C gathering lines. Similarly, several commenters suggested that PHMSA withdraw all proposed amendments related to Type C pipelines.

Similarly, several commenters representing industry opposed the proposed scope of the NPRM based on their evaluation of the PRIA and other claimed shortcomings of the preliminary risk assessment. Kentucky Oil and Gas Association said that PHMSA's cost estimates underestimate the impact of the proposed gathering line requirements and recommended that PHMSA maintain the existing requirements for gathering lines. Industry Trades said that because of the flaws in the proposed regulations and PHMSA's failure to comply with its risk assessment requirements, PHMSA should defer any consideration of requirements for onshore gas gathering to a subsequent rulemaking with additional public notice and comment opportunities. Arkansas Independent Producers and Royalty Owners suggested PHMSA recalculate the emissions calculations in the PRIA and withdraw the proposed regulations for gathering pipelines, commenting that PHMSA underestimated unit costs and safety impacts for leakage surveys and patrols and should have applied the transmission line emissions factor for protected steel gathering lines rather than the EPA emissions factor for gas pipeline leaks in the benefits analysis. Philadelphia Gas Works stated that, for its risk assessment, PHMSA relied on information in the 2021 gas gathering rule that was provided by the Independent Petroleum Producers of America in a 2006 rulemaking that is no longer accessible and said that PHMSA could not rely on this data.

GPA Midstream Association and API stated that PHMSA needs to carefully consider differences between gas gathering, transmission, and distribution lines when establishing new leak detection and repair requirements for regulated gas gathering lines and evaluating the impacts of those requirements in the risk assessment. The commenter noted that while transmission and distribution lines are generally public utilities that can recover additional costs of repairs and leak detection through rate making and other mechanisms, gathering line operators function under "multi-year, bilateral, fixed fee agreements without any mechanism for recovering additional regulatory expenses."

GPA Midstream Association and API said that, compared to Type A gathering line operators currently subject to transmission line requirements, Type B operators complying with the proposed requirements would experience higher burdens that could affect the practicability of the proposed rule. Specifically, Type A gathering line operators are already subject to O&M requirements in part 192 and may therefore be in a better position to implement additional requirements compared to operators of Type B and Type C gathering lines subject to more limited requirements. The commenter added that most operators of Type A and Type B gathering lines also have Class 1 gathering line segments in their systems, which are not currently subject to PHMSA regulations and could impact the practicality and costs of applying additional leak detection and repair requirements to regulated onshore gathering line operators, presumably due to the geographic separation between non-contiguous segments of regulated Type A and especially Type B gathering lines separated by unregulated Type R gathering lines in class 1 locations.

An industry trade group stated that applying leak detection and repair standards to gathering pipelines appurtenant to stations would add redundant patrolling and leakage survey requirements on short segments of pipeline.

A few commenters discussed alternative approaches to gathering line regulation. The North Dakota Petroleum Council stated the regulations for gathering pipelines were burdensome and duplicative and suggested that PHMSA provide the opportunity for operators to demonstrate compliance with gas gathering requirements through compliance with State programs.

Leak Detection and Repair Requirements

Multiple leak detection technology providers supported the proposed increased frequency in leakage surveys for gathering pipelines. Bridger Photonics supported a twice-yearly leakage survey requirement for gathering pipelines outside of Class 4 locations. The MD Attorney General et al. said that the proposed increases in the frequency of leakage surveys and patrolling for offshore gathering and Types A, B, and C gathering pipelines located in HCAs in Class 1, Class 2, or Class 3 locations would fill a major regulatory gap. The PST supported the proposed leakage survey and patrol requirements for regulated gas gathering lines but suggested that PHMSA should not allow operators to perform leakage surveys without leak detection equipment on regulated gas gathering lines. They also commented that PHMSA should require operators perform more frequent surveys of gas gathering lines in general, particularly at valve sites, launchers and receivers, and tanks (e.g., for temporary gas storage or for the removal of water and liquid hydrocarbons) on gathering lines. The PST also recommended PHMSA require operators to perform leakage surveys 4 times each calendar year for Type A and Type B gathering lines, 3 times each calendar year for Type C gathering lines, and 2 times each year for Type R gathering lines. In contrast, Kinder Morgan opposed PHMSA requiring leakage surveys on gas gathering lines any more frequently than proposed in the NPRM, and another industry representative suggested PHMSA eliminate the requirements that PHMSA pre-approve an operator's use of human senses as a leak detection technique for Type C gathering pipelines.

Encino Environmental Services commented that the proposed patrol requirements applicable to Type A, Type B, and Type C gathering pipelines were appropriate. On the other hand, comments from industry trade associations stated that additional patrol requirements for operators of gathering lines would be onerous and should not be required without PHMSA considering the class location of a pipeline, given that gathering lines are often located in remote areas. The Differentiated Gas Coordinating Council said it would neither be reasonable nor provide value for operators to conduct patrols of gathering lines monthly. Multiple industry trades and operators stated that PHMSA did not identify any safety benefits attributed to the significant increase in the frequency of patrolling gathering lines, noting further that the application of transmission-based patrol requirements to gathering lines was unreasonable and would add a significant burden to operators. An industry representative said that the concept of HCAs has never applied to Type A, Type B, and Type C gathering lines, and requiring gathering line operators to determine whether their lines exist in HCAs would be a significant regulatory expansion and beyond the scope of what Congress specifically outlined would be appropriate and justified.

Williams Companies, Inc. said that PHMSA did not provide an adequate explanation for why it was necessary to increase the frequency of patrols of gas gathering lines, particularly for Type C lines that just recently became regulated and whose operators are still working to set up programs. They suggested PHMSA instead require operators to patrol Type A gathering lines twice a year, not to exceed 7 months, and once a year for Type B and Type C gathering lines. GPTC and an industry representative said it was unclear what monthly maintenance tasks operators would be performing on Type B and Type C lines that would make the proposal cost-neutral. An industry representative said PHMSA should list the type of monthly tasks operators could concurrently perform on Type B and Type C gathering pipelines or instead decrease the frequency of patrols required.

Marcellus Shale Coalition suggested PHMSA retain the exceptions in § 192.9(f) for Type C gathering pipelines applicable to leakage surveys and suggested applying this exception criteria to the patrol requirements PHMSA proposed for Type B and Type C gathering lines.

Procedural Manuals

The MD Attorney General et al. supported PHMSA's proposed requirements regarding procedure manuals, reasoning they would align with section 114 of the PIPES act of 2020. Industry Trades, GPA Midstream Association, et al., and an operator did not oppose the proposed requirements for procedure manuals in principle but raised concerns that the included cross-reference to § 192.605 would impose additional regulatory requirements beyond those listed in § 192.9, and that these impacts were not adequately described or accounted for in the risk assessment.

An industry representative suggested that PHMSA clarify whether operators of Type B and Type C gathering lines are required to comply with the requirements related to continuing surveillance, investigation of failures, and control room management. Another operator requested PHMSA clarify what requirements listed in § 192.605 would apply to gathering lines. GPTC stated that PHMSA's estimates for operators to develop and maintain operational manuals were drastically underestimated, and that GPTC was unable to reproduce the estimated life-cycle costs of developing or maintaining the plans.

KOGA said that cross-referencing the procedure manual requirements in § 192.605 in their entirety would impose additional design, configuration, material, and resource costs. They also raised concerns about implementation of the section 114 language and asked if there was a "standard list" of materials or components that are "known to leak." Renegade Energy Advisors, LLC and other commenters suggested PHMSA provide an 18-month extension after the publication date of the final rule for Type B and Type C gathering line operators to comply with the procedure manual requirements.

National Pipeline Mapping System

Multiple environmental and public advocacy groups, a form letter campaign, and a few individual commenters stated that PHMSA should require all pipelines be subject to GIS reporting via the NPMS, including all types of gathering pipelines. Rep. Rick Larsen, et al. said the proposed requirement would expand damage prevention efforts and help ensure that all leaks are found and repaired, which would in turn increase public safety.

Industry Trades, Petroleum Alliance of Oklahoma, GPTC, an industry representative, and KOGA suggested that PHMSA remove the requirement for gathering line operators to participate in NPMS, as the requirement is onerous and potentially not cost-beneficial. Multiple industry trades said that complying with the NPMS is a large administrative burden for small or new operators, as not all small gathering operators would have GIS capabilities necessary to collect and submit the information required by the NPMS, and the required data has not historically been maintained by operators. The commenters also said that PHMSA's cost-benefit analysis does not accurately take into consideration the associated costs of data collection and provided examples of those costs. GPA Midstream Association, et al., Industry Trades, Texas Pipeline Association, and Texas Chemistry Council said that it would not be reasonable for PHMSA to impose additional burdens on pipeline operators to provide granular NPMS information beyond what is already being provided to authorities administering State damage prevention programs.

The Petroleum Alliance of Oklahoma, Senator Cruz, et al., the North Dakota Petroleum Council, the Associations, and GPA Midstream Association, et al. said that the Pipeline Safety Act and 49 U.S.C. 60132 specifically excludes distribution and gathering systems from the NPMS, adding that PHMSA requiring gathering operators to participate in the NPMS would be unlawful, unnecessary, and unsupported by the rulemaking record. GPA Midstream Association et.al. commented that the specific exclusion in 49 U.S.C. 60132(a) overrides PHMSA's general authority to collect information from gathering line operators under 49 U.S.C. 60117(c). The Associations said adding roughly five times the existing pipeline mileage to the NPMS may degrade an already overly strained system.

Producers Midstream said the proposed requirement could create opportunities for terrorists and impede the Department of Homeland Security by adding most midstream pipelines to a public viewing mapping system. The commenter urged PHMSA to withdraw the proposed requirement or redact information in the public-facing viewer if this requirement is maintained. Multiple environmental advocacy groups added that PHMSA should make NPMS data more transparent and accessible.

GPA Midstream Association, et al. suggested that PHMSA add an explicit exception for gathering lines from the NPMS requirements in the final rule. NAPSR suggested PHMSA provide a more limited exception for Type B gathering lines, which operate at lower pressures similar to gas distribution lines compared to gas transmission, Type A, and Type C gathering lines that operate at high pressure. The PST and environmental advocacy groups suggested PHMSA also require NPMS reporting for Type R gathering lines in the final rule.

Requirements for Type R Gathering Lines

The PST, EDF, multiple environmental and public advocacy groups, U.S. House Rep. Rick Larsen, et al., State Rep. David Michel, a few form letter campaigns, and numerous individual commenters said that operators should be required to find and fix leaks on all gathering pipelines, including currently unregulated Type R lines. These commenters stated that because many gathering lines are in locations where leaks would be hazardous to human health and the environment, reducing pollution from these gathering lines would improve long-term health outcomes and reduce methane emissions.

The Responsible Decarbonization Alliance and an individual commenter urged PHMSA to regulate Class 1 gathering lines, reasoning these lines can contain within their PIRs rural, low-density areas that deserve the same level of protection as high-density areas. The commenter added that, while resource limitations might have excused the lack of protection for these areas in the past, modern technology has now made it inexcusable.

Several industry representatives opposed PHMSA applying any proposed requirements of the NPRM to Type R gathering pipelines and any pipelines associated with natural gas production operations.

Other

KOGA commented that that §§ 192.760 and 192.763 have OQ and part 199 drug and alcohol requirements that are not currently applicable to Type B and Type C gathering pipelines. They recommended PHMSA consider simplified compliance requirements for such pipelines similar to the alternative compliance method for OQ requirements in subpart N that PHMSA currently allows for Type A gathering lines in § 192.9(c).

GPTC suggested PHMSA consider a 1-year compliance timeline for Type B operators to develop and implement procedures for emergency plans in accordance with § 192.615, consistent with the implementation timeline adopted for Type C gathering lines in the past.

Industry trades expressed concern about the proposed requirement for operators of regulated gas gathering lines to maintain pressure relief devices in § 192.773. Specifically, they noted that the vast majority of Type C gathering lines were installed prior to the establishment of Type C as a classification of regulated onshore gathering line, and that therefore such lines were not required to be equipped with pressure relief devices meeting existing or proposed requirements in part 192.NAPSR supported recordkeeping requirements for leak repairs but urged PHMSA to require gathering line operators to comply with general recordkeeping requirements for gas transmission pipeline repairs specified as outlined in § 192.709. Existing § 192.709 requires operators retain records of repairs to pipe and pipe-to-pipe connections for the life of the pipeline. It also requires operators retain records of patrols, surveys, inspections and tests and records of repairs to facilities other than pipe for 5 years or until the next patrol, survey, or inspection, whichever is later.

Kairos Aerospace suggested that PHMSA consider allowing operators to consider emission reductions from Type R lines along with Type C lines as a measure of overall program effectiveness to encourage an alternative ALDP. RMI suggested that PHMSA extend IM requirements in subpart P to part 192 to Type A, Type B, and Type C gathering lines.

3. GPAC Deliberation Summary

The GPAC was briefed on PHMSA's proposals regarding the applicability of the proposed rule to gas gathering lines on December 1, 2023, and again on March 25, 2024, during the first and second GPAC meeting for this rulemaking, respectively. PHMSA's December 1, 2023, briefing included a presentation of the proposed regulatory language, a discussion of its costs and benefits, and an overview of material comments from stakeholders on the proposal. In response to requests for additional information from members during the first meeting and the availability of annual report information, the March 25, 2024, briefing included additional background on existing gas gathering regulations, annual report information about operators and mileage of Type C gathering lines, information about leaks and emissions from gas gathering lines, and information about PHMSA's legal authority to regulate gas gathering lines.

Following the December 1, 2023, briefing by PHMSA staff, the GPAC provided an opportunity for members of the public to provide feedback. Representatives of gas gathering operators and industry trade associations referenced their written comments, highlighting concerns regarding the risk assessment performed by PHMSA related to Type C gathering lines, including a lack of consideration of non-regulatory alternatives, the unavailability of Type C annual report information at the NPRM stage, and noting that gathering lines are not public utilities and therefore do not have cost-recovery mechanisms available to other types of facilities. Gathering industry and trade association stakeholders called attention to the high estimated compliance costs associated with PHMSA's proposals, as well as historical and continuing costs incurred by gathering pipeline operators in order to comply with more recently implemented standards for gathering lines. Industry stakeholders noted that there are approximately 90,000 miles of Type C gas gathering lines that only recently became classified as regulated gathering lines, and that PHMSA should give such operators sufficient time to gain experience and data, and implement existing rules before proposing or enforcing new standards for leak detection and repair. Several of these public commenters noted that Type C gathering lines were not included in section 113 of the PIPES Act of 2020. One industry representative commented that requiring ALDP and prescriptive repair standards for Type C facilities that, unlike transmission and distribution operators, do not have decades of compliance experience was impracticable. Other public commenters representing gathering operators indicated that updating and implementing O&M manuals will take more time than the proposed 6-month effective date, and that monthly patrols were not cost-effective for rural gathering lines. A representative of a pipeline safety advocacy organization commented that while Type C gathering lines are located in rural areas, rural communities experience public safety risk from gas gathering lines, citing the 2018 incident caused by a leak on a previously unregulated gathering line in Midland, Texas, that killed a 3-

year-old girl.[414] Regarding PHMSA's proposal to require gathering line operators to participate in the NPMS program, an individual representing a pipeline safety advocacy organization expressed a need to know where potentially hazardous regulated gas gathering lines are located. Stakeholders representing the gas gathering industry and a gas distribution trade association opposed NPMS requirements for regulated gas gathering lines due to the scope of 49 U.S.C. 60132, the compliance burden, and because other programs address the potential uses of NPMS as a safety tool. Finally, an individual representing gas gathering trade associations commented that it would be inappropriate to expand part 192 requirements to unregulated Type R gathering lines.

GPAC discussion began on December 1, 2023, but no votes were made on the topic of gathering lines until the first day of the second meeting on March 25, 2024. A Committee member representing an operator with gas gathering assets provided background on the regulation of gas gathering lines, including establishing standards for Type C gas gathering lines in class 1 locations. A Committee member representing the public stated their support for the proposal to extend leak detection and repair standards to Type C gathering gas gathering lines and further suggested establishing standards for Type R lines, citing multiple studies observing fugitive methane emission from gas gathering lines far exceeding EPA and emissions modeling provided in their written comments estimating emissions reductions of up to 80 percent for gas gathering lines compared with baseline practices. They further described threats to public health

[414] Sorghan, Mike and Lee, Mike, "Pipeline in fatal blast had a dime-sized hole in it," https://www.eenews.net/articles/pipeline-in-fatal-blast-had-a-dime%e2%80%91sized-hole-in-it/ (last accessed Sept. 10, 2024). E&E News. (Sept. 10, 2018).

from hazardous air pollutants and environmental justice impacts related to leaks and incidents. During the Committee's discussion, a member representing the public also provided an overview of emissions studies, which found that leaks "in the gathering pipeline systems are two orders of magnitude larger than what we have been seeing in the transmission or distribution sector," and observed average emissions rates between 150 and 200 kg per hour. Committee members representing industry commented that most emissions are from facilities covered by EPA and OSHA standards rather than pipeline leaks, and echoed comments from members of the public noting that while operators are working on leak management technologies, they could not practicably implement PHMSA's proposed ALDP requirements within the timeline that would likely be prescribed for other pipeline facilities such as gas transmission and distribution lines. Committee members representing the public countered that pipelines themselves are not covered by other Federal emissions requirements, that aerial surveys were currently being performed by gas gathering pipeline operators, and were demonstrated to be practicable. Another member representing the public observed that construction practices did not meet the same standards as on jurisdictional transmission lines, potentially explaining the difference in leakage between facility types.

Committee members representing industry acknowledged the prior discussion of leaks from gathering systems and agreed that standards were appropriate but suggested limiting the final rule to Type A and Type B gas gathering lines covered by the PIPES Act of 2020, and considering standards in the future for Type C gathering lines based on additional reporting information and compliance experience among regulated gas gathering operators. A Committee member representing the public commented that they supported leakage survey and repair requirements for Type C gathering lines and statements made by other public members. They further argued that including Type C lines was not inconsistent with the congressional intent of the PIPES Act of 2020 since the mandate addressed gathering lines that were jurisdictional at the time the act was enacted, and that it also falls under PHMSA's authority under 49 U.S.C. 60102(a). A Committee member representing a transmission operator agreed PHMSA had the authority to regulate Type C but that a proposal should better account for the fact that previously unregulated gathering line operators are starting from a different place compared with other regulated assets. A member representing the public suggested that concerns about ramping up programs could be addressed through compliance timelines rather than through the scope of the rule. Committee members reached general agreement on the need to address leak detection and repair standards for Type C and potentially Type R gathering lines but remained divided on whether to address that need in a final rule in this proceeding or via a separate rulemaking. For the rest of the day the Committee discussed at length the state of maturity of the gas gathering industry, whether a separate rulemaking or alternative compliance timelines was necessary for Type C and Type R gathering lines, to what extent prior recommendations were appropriate for regulated gas gathering lines, the extent of PHMSA's authority to establish leak detection and repair standards for Type C gathering lines, and GPAC's role with respect to opining on legal authority or making recommendations on procedural matters. Additionally, many members expressed a desire for more data and information concerning regulated gathering lines and Type C in particular, though members representing the public described currently available information and commented that there was sufficient information already available to determine that there is an urgent problem with fugitive greenhouse gas emissions from gas gathering pipelines.

Discussion continued during the first day of the second meeting on March 25, 2024. In response to the stated desire for more information on Type C gathering line operations and integrity performance, PHMSA staff provided an updated briefing with information on mileage and ownership of Type C gathering lines from operators' most recent annual reports and information about leaks and emissions from such facilities. Likewise, a Committee member representing industry provided maps comparing Type R gathering lines and smaller-diameter Type C lines to larger diameter Type C gathering lines. The committee member pointed to the map to support an assertion that these Type R gathering lines and smaller-diameter Type C lines are located further upstream within a gathering system closer to individual wells and had a complex web-like structure compared with larger-diameter Type C, which tended represent more linear trunklines connecting production fields to gas processing plants. For these smaller diameter lines, members representing industry described concerns about the decreased efficiency (but not effectiveness) of aerial surveys of complex systems, the maturity of smaller operators' compliance programs for Type C lines previously excepted from leakage surveys under § 192.9(f), and the practicability of ramping up frequent survey intervals in short time pending cooperative agreements for aerial surveys or advances in satellite technology. However, the Committee member conceded that larger diameter trunk-lines currently subject to leakage survey requirements (i.e., not excepted under § 192.9(f)) were likely to be higher risk and already have more mature compliance programs.

In the context of this comparison, the GPAC member described the existing classification under § 192.9(f), which provides an exception for certain part 192 requirements (including, until this final rule, leakage survey and repair requirements) for Type C gathering lines with an outside diameter of less than or equal to 16 inches in outside diameter that are not located within a potential impact circle or class location unit containing a building intended for human occupancy or other impacted site. They and other Committee members representing industry suggested the scope of § 192.9(f) provided a starting point for discussion of drawing a line between larger-diameter facilities with operational characteristics similar to transmission lines, established compliance programs, and linear layouts conducive to aerial survey programs from more complex smaller-diameter systems that may be more challenging to survey frequently until operators can develop cooperative aerial survey agreements or advance technology in satellite monitoring.

Based on this information, the Committee came to a general agreement on applying annual leakage survey and repair standards for Type C gathering lines that were already subject to leakage surveys (i.e., with an outside diameter greater than 16 inches or located near buildings). Debate continued on whether, how, and when to address LDAR standards for Type C gathering lines with an outside diameter of less than or equal to 16 inches and not located near buildings that are currently excepted under § 192.9(f). When asked about the significance of methane emissions from regulated gas gathering lines, a Committee member representing the public described studies indicating large volumes of emissions from such facilities compared with other types of pipeline facilities. They further observed that this could be partly explained by the fact that such facilities were never subject to leak detection and repair requirements and that observed leakage could be lower in the future following an initial survey and repair of existing leaks. The Committee member has observed large leaks that range from approximately 10 kg/hr to over 100 kg/hr on these lines, but noted that smaller leaks below 10 kg/hr do not contribute significantly to total detected emissions. Another member representing the public supported those conclusions but noted that small- to medium-size leaks also contribute to climate change, aerial survey methods have been demonstrated to be practicable, and that access to information about regulated gathering lines via the NPMS could improve the quality of emissions studies. A Committee member representing a gas transmission and gathering operator responded that their experience in Pennsylvania differs from the Permian Basin because of differences in leakage rate and topography. Committee members representing industry further noted that, for the reticulated, smaller-diameter assets, aerial surveys would require matrix flying over production basins, which would become impracticable and potentially counter-productive (due to aircraft emissions) when performed frequently and redundantly by multiple operators within the same basin.

A Committee member representing the public observed that the majority of Type C mileage was operated by a handful of large operators, many of which operate other regulated assets subject to leakage survey requirements. They continued that if the concerns about practicability were concerns about costs, they could be addressed through compliance timelines and survey frequencies instead of via the scope of the requirements. A member representing the public suggested considering alternative survey frequencies for smaller-diameter Type C lines such as 3 or 5 years, similar to what was discussed previously for gas distribution lines. Members representing industry commented that while annual leakage surveys of 90,000 miles of previously excepted gathering lines was not practicable, a discussion could be had on a less-frequent survey requirement (in addition to the larger-diameter lines discussed previously). After a caucus, members representing operators stated they could entertain a 5-year survey, but that the effort would likely require the industry to develop cooperative agreements to perform aerial surveys over wide areas. After some deliberation considering the appropriateness of considering an intermediate frequency of 3 years for some or all smaller-diameter lines, members representing the public agreed on the 5-year survey frequency, provided the GPAC clarify that the ALDP performance standard applicable to transmission lines applied (10 kg/hr for screening surveys, see section III.D), and if a first survey was required by the compliance date of the rule. The GPAC unanimously supported this framework.

After agreeing on an approach for standards applicable to Type C gathering lines, members deliberated on the proposal to require operators of regulated onshore gas gathering lines to participate in the NPMS. Two members representing the public supported the proposed requirement to require NPMS and also supported proposing to incorporate Type R gathering lines as an important public awareness tool. One of those members and a third member also representing the public described the benefits for researchers and operators from being able to attribute observed emission sources to particular types of pipelines. All Committee members representing industry opposed the legal and safety basis for the proposed NPMS requirements, and described significant burden associated with complying with NPMS requirements for GIS data submissions. Committee members were particularly concerned about the burden for regulated gas gathering operators who may not have GIS systems and personnel in place and would have to gather location data or digitize potentially incomplete maps. Some other members representing government similarly opposed the proposal, primarily on legal grounds. Various members proposed potential compromise suggestions such as alternative submission requirements, allowing operators to collect geospatial information opportunistically, and excluding low-stress Type B gathering lines; however, no proposed alternative gained traction. After significant deliberation members did not achieve agreement on this topic and were evenly split in a 7-7 vote on the technical feasibility, reasonableness, cost-effectiveness, and practicability of NPMS requirements for Type A, Type B, and Type C regulated onshore gas gathering lines.

4. GPAC Recommendation

After extensive deliberation of the practicability of leakage surveys of different frequencies for different types of lines, the GPAC unanimously recommended that the proposed rule with respect to Type A, B, and C gas gathering lines was technically feasible, reasonable, cost-effective, and practicable if the following changes were made to requirements for Type C gathering lines.

- Extend GPAC-recommended LDAR requirements, including GPAC-recommended ALDP performance standards, to all Type A, B, and C gathering pipelines.

- Adopt an annual leakage survey interval for Type C gathering pipelines that are: ≥ 16 inches in outside diameter, or 8 inches to 16 inches in diameter if the segment contains a building intended for human occupancy or other identified site within the potential impact radius or class location unit.
- For other Type C gathering lines, adopt a 5-year leakage survey interval, with a first survey occurring on the compliance date of the rule.

The Committee did not achieve agreement on NPMS requirements and discussion culminated in a tied 7-7 vote concerning the feasibility, reasonableness, and cost-effectiveness, and practicability of NPMS requirements for Type A, Type B, and Type C regulated onshore gathering lines.

The GPAC did not provide recommend changes to requirements for offshore gas gathering lines beyond those generally applicable to gas transmission lines.

5. PHMSA Response

Summary and Applicability to Type A, Type B, Type C, and Offshore Gathering lines.

This final rule adopts the requirements for Type A, Type B, Type C, and offshore regulated gas gathering lines largely as they were proposed and described in the NPRM and PRIA with the exception of the proposal to require operators submit GIS information associated with onshore gas gathering lines under the NPMS reporting program in accordance with § 191.29, and with changes to the survey frequency and the leak detection performance standard discussed in III.B and III.D, as well as the repair criteria discussed in III.H and III.I. With respect to specific requirements applicable to regulated gas gathering lines, changes in the final rule applicable to gas transmission lines also apply to regulated gas gathering lines subject to those requirements. These changes address GPAC recommendations and concerns raised by public comments and are expected to significantly reduce the burden of complying with this final rule. However, PHMSA did specifically revise certain requirements to address considerations unique to the functional and operational characteristics of regulated onshore gas gathering lines and address recommendations from the GPAC and public comments; specifically, this final rule adopts the GPAC-recommended survey frequency for Type C regulated onshore gathering lines and simplifies the requirements for procedure manuals comparative to the NPRM.

For Type A and Type B regulated gas gathering lines, the amendments in this final rule implement mandates from the PIPES Act of 2020 to establish LDAR program requirements to meet the need for gas pipeline safety and to protect the environment for regulated gas gathering lines in Class 2, Class 3, and Class 4 locations.[415] As described in greater detail in section III.T, PHMSA disagrees that it lacks proper legal authority to adopt appropriate safety standards for Type C and offshore gas gathering lines. As described in greater detail in this section, there are clear, demonstratable, significant, and cost-effective benefits for establishing leak detection and repair standards for such facilities.

Applying leak detection and repair requirements to regulated gas gathering lines, the majority of which are Type C lines in Class 1 locations, has both the highest net benefits and cost-effectiveness ratio of any component of this final rule. PHMSA has revised the final RIA with respect to the costs and benefits of enhancing leak detection and repair standards to address

[415] 49 U.S.C. 60102(q)(1).

changes elsewhere in the rule that result in decreased benefits and other changes to address other assumptions and parameters that commenters contended undercounted costs. These changes are described in the final RIA itself, which is available in the docket for this rulemaking. PHMSA's consideration of quantified and unquantified environmental benefits is appropriate and is explicitly required by law.[416] Finally, while the benefits of leak detection and repair activities on regulated gas gathering lines are highly cost-effective, PHMSA has nevertheless made changes to the requirements for the ALDP performance standard (section III.D), the frequency of leakage surveys and patrols (section IIII.B), and repair requirements (sections III.H and III.I) to address concerns from public comments and the GPAC concerning the practicability of the rule as applied to gas transmission and regulated gas gathering lines. Sections 2.2.5 and 6.6.2 of the final RIA considers a non-regulatory alternative where Type C and offshore gas gathering lines are excluded from LDAR requirements. This alternative reduces costs by excluding the vast majority of regulated gas gathering lines from the LDAR requirements in the final rule. However, as a consequence, quantified environmental benefits and unquantified safety and environmental benefits also drop, and in this alternative such benefits decline more than the decrease in estimated cost. Therefore, this alternative results in much lower net benefits and a lower cost-effectiveness ratio.

While the substantial quantified net benefits from gathering line requirements in PRIA did not include quantified safety benefits from preventing and mitigating incidents, key portions

[416] 49 U.S.C. 60102(b)(1)(B)(ii), (b)(2)(A)(iii), (b)(5), (q)(1)(B), and (q)(B)(i), see section III.T for additional information.

of the rule applicable to regulated gas gathering lines are focused primarily or exclusively on public safety, and the final RIA includes a sensitivity analysis estimating quantified benefits from the safety benefits associated with impacts to human health. For example, 8 out of the 9 criteria for high-priority grade 1 leaks and 8 out of the 10 criteria for medium-priority grade 2 leaks directly address hazards to people and property,[417] and the adoption of emergency plans for Type B gathering lines (discussed further later in this section) is explicitly a safety standard. These changes result in additional unquantified safety benefits that further justify the costs of the rule, including reduced risk to the public associated with the prompt repair of higher-risk leaks on Type C gathering lines that were previously exempted from the prior requirements to repair hazardous leaks, and reduced risks to public safety due to the scheduled repair of grade 2 and larger grade 3 leaks on all types of regulated gas gathering lines. Finally, the NPRM and PRIA included qualitative discussion of additional adverse health impacts from pipeline leaks, particularly leaks from gas gathering lines transporting unprocessed natural gas that is more likely to contain VOCs and HAPs, such as benzene, that are harmful to public health and safety when released into the atmosphere via leaks. In a sensitivity analysis in the final RIA, PHMSA has quantified public health benefits associated with reducing emissions of such pollutants.

The functional and operational characteristics of Type C regulated gas gathering lines relevant to leak detection and repair warrant leak detection and repair standards at least as stringent as what this final rule applies to regulated gas transmission lines. Type C gathering lines, by definition, share pipe diameter and operating pressures comparable to gas transmission

[417] § 192.760(b)(1).

pipelines and are susceptible to similar integrity threats. Table 1 to paragraph (c)(2) of § 192.8 defines a Type C regulated onshore gathering pipeline as a gathering line in a Class 1 location with an outside diameter greater than or equal to 8.625 inches that operates at high pressure, and is as follows:

- The pipeline segment is metallic and the MAOP produces a hoop stress of 20 percent or more of SMYS,
- The pipeline segment is metallic and the MAOP is more than 125 psig if the stress level is unknown, or
- The pipeline segment is non-metallic and the MAOP is more than 125 psig.

These pressure criteria mirror the definition of a gas transmission line, which includes any pipeline other than a gathering line that has an MAOP producing a hoop stress of 20 percent or more of SMYS.

The operation of regulated gas gathering lines, including Type C gathering lines, may differ in some ways from gas transmission lines. However, in total, these differences have resulted in an increased observed frequency of leaks and increased total emissions attributed to gas gathering pipeline leaks compared with gas transmission pipelines. Specifically, emissions factors adopted by the EPA, data on leak repairs reported by operators on their annual reports, and scientific studies of emissions from gas gathering lines all support a conclusion that gathering lines are more susceptible to leakage compared with gas transmission lines subject to the requirements of this final rule. In the 2024 U.S. GHGI, the EPA attributed an emission factor for natural gas "gathering and boosting pipeline leaks" of 245.0 kg/hr per year based on information submitted to the EPA in accordance with GHGRP requirements. This emissions factor is over 22 times larger than the emissions factor adopted by the U.S. GHGI for gas transmission pipeline leaks, which was established at 10.9 kg/hr per year. For further comparison, this emissions factor is between the emissions factors for protected and unprotected steel gas distribution mains at 96.7 and 861.3 kg/hr per year, respectively. High emissions from gas gathering pipelines in particular have similarly been observed in aerial surveys of gas production basins performed by third-party researchers as described in section II.B.

While overall emission factors and third-party research do not generally distinguish between regulated and unregulated gas gathering systems, data on leak repairs submitted in operator annual reports confirm that regulated gas gathering lines, including Type A and Type C regulated onshore gas gathering lines that, by definition, operate above 20 percent of SMYS, are more likely to leak than gas transmission lines. In the 2023 reporting year, operators reported repairing 1,066 leaks on 296,684 miles of regulated gas transmission pipelines (0.0036 leaks/mile), 46 leaks on 8,583 miles of Type A gathering lines (0.0054 leaks/mile), 201 leaks on 4,620 miles of Type B gathering lines (0.044 leaks/mile), and 619 leaks on 92,927 miles of Type C gathering lines (0.0067 leaks/mile). These figures are likely undercounted for all pipelines, as existing regulations do not require operators repair leaks that are deemed "non-hazardous" to public safety, and even more for Type C gathering lines, as most Type C lines are exempt from leakage survey and repair requirements in accordance with § 192.9(f). Despite these limitations, operators of Type A gathering lines reported 50 percent more leak repairs per mile than gas transmission lines, operators of Type C gathering lines reported 85 percent more leak repairs per mile than gas transmission lines, and operators of Type B gathering lines reported 12 times as many leaks per mile as gas transmission lines. Finally, the difference in leakage rate between gas transmission and Type A gathering lines, which have identical leakage survey requirements, indicates that the difference in leakage rates for Type B and Type C gathering lines compared to gas transmission lines cannot be solely explained by the previous requirement in § 192.9 for operators of Type B and Type C gathering lines to use leak detection equipment when performing leakage surveys in accordance with § 192.706, which was not previously required for most Type A gathering lines or gas transmission lines.

Because of clearly documented evidence that leaks from gas gathering lines represent a significant share of methane emissions from natural gas pipeline leaks that is, at minimum, on par with gas transmission lines, PHMSA determined that it is necessary and appropriate to issue standards for leak detection and repair programs for Type A, Type B, and Type C regulated onshore gas gathering lines in this final rule similar to those for gas transmission lines. Additionally, due to both public safety concerns and the previously described environmental impacts, the final rule also closes regulatory safety gaps for Type B and Type C gathering lines with respect to visual right-of-way patrols (§ 192.705); operations, maintenance, and emergency response procedures (§ 192.605); and, for Type B gathering lines only, emergency planning requirements set forth in § 192.615. PHMSA has historically imposed each of those requirements on gas transmission and Type A gathering pipelines precisely because of the self-evident, appreciable public safety benefits they entail.[418] Although PHMSA previously declined to extend those minimal requirements to Type B and Type C gathering pipelines in a prior rulemaking (representing the majority of part 192-regulated gathering pipeline mileage),[419] the public safety and environmental risks from Type B and Type C gathering pipelines discussed throughout this final rule warrant removal of those regulatory gaps. For Type B gathering lines, the public safety risks of any incident are evident due to the location of those pipelines in densely populated Class 2, Class 3, and Class 4 locations. For Type C gathering lines, the high operating pressures and large diameters of Type C gathering lines entail risks to public safety similar in type to those posed by Type A gathering lines.[420] And, as explained above, leaks from any type of natural gas gathering pipeline contains VOCs and HAPs, exacerbating public safety and environmental risk. Leaks of unprocessed natural gas also contain corrosive materials that can accelerate leak degradation.[421] PHMSA considers the amendments described above, which include significant changes to address concerns raised by commenters, to be reasonable, technically feasible, cost-effective, and practicable. PHMSA expects that some Type B and Type C gas gathering pipeline operators may already voluntarily comply with the requirements that PHMSA is finalizing in this rulemaking, particularly with the changes to the ALDP performance standard and the frequency

[418] 71 FR 13289, "Gas Gathering Line Definition; Alternative Definition for Onshore Lines and New Safety Standards," at 13292 (Mar. 15, 2006).
[419] Gas Gathering RIA at 15 (noting a total of ca. 90,000 miles of Type C gathering pipelines) and 30 (noting a total of ca. 11,000 miles of Types A and B gathering pipelines) (Nov. 15, 2021), PHMSA-2011-0023-0488.
[420] 86 FR 63266 at 63267. (Nov. 15, 2021).
[421] Leaks from part 192-regulated gathering lines transporting flammable, toxic, or corrosive gases other than natural gas also entail their own safety and environmental risks.

of leakage surveys and patrols.[422] Certain operators of Type B and Type C gas gathering pipelines may also have gas transmission or Type A gathering pipelines within their systems subject to similar procedural manual, recordkeeping, and pressure relief device requirements under Federal or State law; those operators could adapt and extend their existing procedural manual and recordkeeping and pressure relief device design and configuration protocols to their Type B and Type C gas gathering pipelines. Viewed against those considerations and the compliance costs estimated in the RIA, PHMSA's amendments in this final rule related to regulated gas gathering lines will be a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this final rule and its supporting documents. Lastly, the compliance timelines adopted in this final rule, including the extended survey frequency for certain Type C gathering lines, would provide operators ample time to implement requisite changes to existing procedural manuals and protocols, conduct any accompanying personnel training, and manage any related compliance costs.

Leak Detection, Repair, and Patrol Requirements

Consistent with the unanimous recommendation of the GPAC, PHMSA is applying the leak detection and repair standards in this final rule for gas transmission pipelines to regulated onshore gas gathering lines, as those are determined in accordance with § 192.8. The final rule likewise adopts the proposal to apply leak detection and repair standards, as amended in the final rule, to offshore gas gathering lines. PHMSA is, however, also promulgating the GPAC-recommended revisions to the leakage survey frequencies for Type C gathering lines. This

[422] See the discussion of baseline compliance for regulated gas gathering lines in section 3.1.1 of the final RIA.

amendment as it applies to regulated gas gathering lines is described in greater detail in section III.B. As a supplement to operators performing leakage surveys with leak detection equipment, this final rule also retains the proposed requirement for operators to perform visual right-of-way patrols for Type B and Type C regulated gas gathering lines. However, the Committee and other commenters raised concerns about PHMSA's assumption that all operators routinely conduct monthly patrols. While some operators perform frequent aerial patrols, that practice is not universal in the industry, particularly for operators of regulated gas gathering lines. Since baseline compliance is lower than PHMSA initially estimated, monthly patrol costs for operators that do not currently perform monthly aerial patrols may therefore be more significant than originally accounted for. Additionally, while patrols may be a cost-effective way to address some integrity threats like excavation damage and earth movement, PHMSA acknowledges that compliance costs for these requirements may be higher for Type B and Type C gathering lines that were not previously required to perform patrols at all, and therefore are likely to have lower rates of baseline compliance. Therefore, in this final rule, PHMSA has changed the patrol frequency to annual rather than the monthly patrol frequency proposed in the NPRM. (see section III.B for additional discussion of the patrol requirements for gas transmission and regulated gas gathering lines.)

Adopting leakage survey and repair requirements are necessary for implementing mandates from the PIPES Act of 2020 for Type A and Type B regulated gas gathering lines and to help ensure adequate standards are in place to protect public safety and the environment from the consequences of pipeline leaks regardless of location. As described in the final RIA for this rulemaking, these changes will result in substantial reductions in natural gas releases from regulated natural gas gathering lines, resulting in significant quantified benefits from reducing greenhouse gas emissions, avoiding public health impacts from natural gas releases, and avoiding economic waste from releasing valuable natural gas into the atmosphere. These changes will also result in unquantified safety benefits; in particular, eliminating the exception in § 192.9(f)(1) from the requirement to repair hazardous leaks in § 192.9(e)(1)(viii) for certain Type C gathering lines will help ensure that all gathering line operators are prioritizing repairing leaks based on their potential for harm to people, property, and the environment.

Regarding leakage surveys, per this final rule, Type A, Type B, and offshore gas gathering lines are subject to the leakage survey frequency specified in § 192.706 for gas transmission lines, which is described in further detail in section III.B. Compared to the prior status quo, the primary change being made in this final rule for these facilities is the requirement for operators of Type A, Type B, and offshore gas gathering lines to perform leakage surveys in accordance with the ALDP requirements in § 192.763 (see section III.D and III.E for further discussion of the ALDP program requirements), including a requirement for operators to use leak detection equipment during such surveys except for surveys performed on pipeline segments submerged below water. Additionally leakage surveys of valves, flanges, pipeline tie-ins with valves and flanges, ILI launcher and ILI receiver facilities, and pipelines known to leak based on material, design, or past operating and maintenance history, must be surveyed twice each calendar year in Class 2 and Class 3 locations and four times each calendar year in Class 4 locations.[423] This final rule also clarifies that PHMSA does not expect operators to identify HCAs on regulated gas gathering lines, as gathering lines are not currently required to comply with gas transmission IM requirements in subpart O of part 192. While these new survey frequencies PHMSA is finalizing in this rulemaking will increase the frequency of leakage surveys at locations with a higher likelihood of leakage or higher potential consequences to public safety, PHMSA expects the vast majority of Type A and Type B gathering line mileage will continue to be surveyed once each calendar year.

For Type C regulated gas gathering lines, this rulemaking finalizes the NPRM's proposal to eliminate the § 192.9(f) exception for leakage survey and repair requirements but adopts survey frequencies recommended by the GPAC. Therefore, operators of Type C gathering lines must perform leakage surveys in accordance with § 192.706, comply with ALDP requirements in § 192.763, and grade, investigate, repair, and document leaks in accordance with the new grading requirements in §§ 192.703(c) and (d), 192.709, and 192.760. Consistent with the GPAC recommendation, leak surveys are required at least once each calendar year for Type C gathering lines, except an extended 5-year survey frequency is permitted for Type C gathering lines covered by the scope of § 192.9; the survey frequency is described in greater detail in section II.B. In addition to leakage surveys, the final rule requires operators of all Type C gathering lines to perform right of way patrols annually, resulting in significantly lower costs compared with the monthly patrol frequency proposed in the NPRM.

[423] These amendments to the leakage survey requirements do not apply to pipelines in the ANS in order to minimize repairs in cold weather months. This is described in greater detail in section III.B.

Other public comments and statements from members of the public during the March 2024 GPAC meeting reiterated the potentially grave public safety and environmental impacts of even small leaks on regulated gas gathering lines; one public commenter described the serious impacts to their property that they attributed to a 2019 leak of gas and toxic, flammable condensate from an unregulated Type R gathering line.[424] Consistent with the GPAC recommendation, Type C gathering lines that are located near homes and other buildings intended for human occupancy will be surveyed with leak detection equipment at least annually, regardless of the diameter of the pipeline. Similarly, the adoption of repair requirements in § 192.760 for all regulated gas gathering lines helps ensure that operators will repair all but the smallest leaks (less than 5 SCFH, see section III.H and III.I) within a prescribed timeline and prioritize leaks based on their potential risks to public safety and the environment.

Changes PHMSA made elsewhere in this final rule address concerns about the practicability of operators of regulated gas gathering lines performing leakage surveys and complying with the proposed ALDP and repair requirements. Notably, this final rule adopts performance standards that are more consistent with the EPA's emissions monitoring standards and adopts standards that better accommodate the use of cost-effective aerial survey technologies, continuous monitoring, and the use of OGI and CGIs for non-buried facilities. Regarding repair requirements, as described in greater detail in sections III.H and III.I, PHMSA is generally allowing grade 3 designations for most leaks on gas transmission and regulated gas gathering lines, providing extended grade 2 and grade 3 repair timelines, adopting a higher

[424] GPAC Transcript beginning at 200 (Mar. 26, 2023).

threshold for environmentally significant grade 2 leaks on gas transmission and regulated gas gathering lines of 10 kg/hr, extending certain delay-or-repair provisions to gas transmission lines and regulated gas gathering lines, and including a repair exception for grade 3 leaks with a de minimis release rate. These changes still require the repair leaks on transmission and gathering lines that pose a potential hazard to people, property, and the environment within a reasonable timeframe but reduces compliance costs and provides more flexibility for operators to schedule repairs with other maintenance activities, planned shutdowns, and pipe replacement projects. To the extent that operators use the opportunity to combine leak repairs with maintenance activities, these changes can reduce total emissions by reducing the frequency of repair-related blowdowns.

Complementing leakage surveys, this rulemaking finalizes patrol requirements for Type B and Type C regulated gas gathering lines. However, in order to address comments about the cost and practicability of frequent patrols for lower risk gathering lines, the final rule adopts an annual patrol frequency for Type B and Type C gathering lines rather than the monthly patrol frequency proposed in the NPRM for gas transmission and regulated gas gathering lines, as discussed in section III.B. PHMSA appreciates concerns from commenters that, similar to leakage surveys, costs for frequent patrols may be higher for Type B and Type C regulated gas gathering lines due to lower baseline compliance and the more fragmented structure of gathering systems compared with transmission systems which are likely to be more linear. The revised patrol frequency for Type B and Type C gathering lines therefore results in significantly lower quantified costs.

Adopting patrol requirements complements instrumented leakage surveys by identifying (typically visual) indications of leaks and identifying indications of conditions that could cause leaks and ruptures in the future. This is particularly important considering PHMSA is finalizing a lengthy leakage survey frequency for the majority of Type C gathering lines in this rulemaking. In particular, right-of-way patrols can identify precursors to, or indications of, external force damage, such as excavation activities, flooding, landslides, and other conditions that could cause damage to a pipeline facility. Early identification of these conditions can prevent a release from occurring in the first place or help ensure that damage that has occurred is addressed in a timely manner. Patrols can identify other indications of elevated risk, such as increased population density or changes in class location in the vicinity of a pipeline facility. As described in section II.E, EPA emissions monitoring standards adopt similar requirements for supplementing leak detection equipment with sensory AVO patrols as a part of their emissions monitoring requirements in 40 CFR 60. For example, EPA fugitive emissions monitoring requirements for natural gas facilities in 40 CFR 60.5397b require operators supplement periodic surveys using leak detection equipment with quarterly AVO surveys for wells and monthly AVO surveys for compressor stations.

PHMSA expects, with the changes described above, the amendments to extend leakage survey and right-of-way patrol practices to all Type B and Type C gas gathering pipeline operators are reasonable, technically feasible, cost-effective, and practicable. Visual patrols and leakage surveys using leak detection equipment are widely employed tools adopted by reasonably prudent operators for identifying and mitigating leaks on, or threats to the integrity of, pipelines transporting commercially valuable pressurized natural, corrosive, toxic, or flammable gases. Precisely for that reason, PHMSA expects that some Type B and Type C gas gathering pipeline operators affected by this final rule's requirements for leakage survey and right-of-way patrols may already voluntarily undertake leakage surveys and patrols on their facilities. Similarly, operators of Type B and Type C gas gathering pipelines may also operate either gas transmission or Type A gathering pipelines that are subject to prescriptive periodic leakage survey and patrol requirements under Federal or State law. These finalized amendments, therefore, better align leakage survey and right-of-way patrol practices and requirements for Type B and Type C gas gathering lines with requirements for other part 192-regulated gas pipelines.

With respect to the applicability of this final rule to submerged offshore gathering lines, The final rule permits operators to visually survey submerged pipelines, including submerged offshore gathering lines, and that operators would perform these leakage surveys above the surface of the water. While it is true that a significant portion of methane released from a leak on a submerged natural gas pipeline would be absorbed by seawater, leak on a submerged pipeline identifiable from the surface, either visually or with leak detection equipment, would represent a significant leak that potentially warrants repair under the grading requirements in the final rule.

Procedure Manuals

This rulemaking finalizes a simplified version of the requirements proposed in the NPRM to require operators of all regulated gas gathering lines to have and follow a manual of procedures for complying with part 192 and section 114 of the PIPES Act of 2020. Specifically, this final rule requires operators of Type B and Type C gathering lines to prepare, update, and follow a manual of procedures for complying with the part 192 listed in § 192.9 applicable to the facility, eliminating leaks in accordance with § 192.760, minimizing releases of natural gas, and remediating or replacing pipelines known to leak based on the material, design, or past operating and maintenance history. This simplified requirement is similar to the existing procedure manual requirements for hazardous liquid regulated rural gathering lines in § 195.11(b). Extending the procedural manual requirements in this manner facilitates regulatory oversight of Type B and Type C gathering facilities by PHMSA and State inspectors by aligning documentation requirements with both the amendments in the final rule and existing substantive requirements under § 192.9. It would also dispel any uncertainty among stakeholders regarding application to Types B and C gathering pipelines of the self-executing obligations under section 114 of the PIPES Act of 2020 to eliminate leaks, minimize emissions, and repair or remediate pipelines known to leak based on their material, design, or operating and maintenance history.

PHMSA appreciated the public comments concerned that cross-reference to § 192.605 within these provisions would require operators to perform and have procedures for requirements described in § 192.605(b) and (c) that were not previously required for operators of Type B and Type C regulated onshore gathering lines. Even though the NPRM included language that excluded certain paragraphs within § 192.605 that are not applicable to Type B and Type C regulated gathering lines, PHMSA agrees that the regulatory text could be confusing. To remedy this confusion, in this final rule, PHMSA clarifies this provision by requiring Type B and Type C gas gathering line operators to have a manual of procedures for carrying out the requirements in part 191 and part 192 applicable to the pipeline, eliminating leaks and minimizing releases of gas, and remediating or replacing pipelines known to leak and only included cross references to those paragraphs within § 192.605 that are applicable. PHMSA believes that these revisions should simplify the procedure manual requirements, address the concerns from public comments about the complexity and associated cost of preparing a broader manual of procedures, and address the comments PHMSA received concerning the consideration of those efforts in the PRIA. This change also eliminates any ambiguity concerning whether operators are expected to comply with other parts of part 192 referenced in § 192.605.

Regarding offshore gathering lines, PHMSA disagrees with comments from GPA Midstream and API contending that the section 114 mandate in the PIPES Act of 2020 does not apply to offshore gathering lines. Like other regulated onshore gas gathering lines, offshore gathering pipelines are "regulated gathering lines" as defined in 49 U.S.C. 60101 and therefore are "gas pipeline facilities" subject to 49 U.S.C. 60108 and section 114 of the PIPES Act of 2020.

Emergency Plans for Type B Gathering Lines

This final rule retains the NPRM's proposal to require operators of Type B gathering lines to comply with emergency plan requirements. PHMSA previously adopted such requirements when establishing standards for Type C gathering lines in 2021;[425] however, parallel requirements were not established for Type B gathering lines in that 2021 rule despite

[425] Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments. November 15, 2021. 86 FR 63266.

the potential risk of such lines, since the NPRM for that rulemaking did not address Type B gathering line requirements. PHMSA was concerned that provisions applying to Type B gathering lines, if promulgated in the final rule, would not have been subjected to proper notice and comment. This final rule closes that regulatory gap. The public safety and environmental risks associated with releases, whether they are leaks or more serious incidents, from gas gathering pipelines support PHMSA extending emergency planning requirements to Type B gas gathering pipelines, which are, by definition, located in densely populated Class 2, Class 3, and Class 4 locations per § 192.8. The emergency planning requirements at § 192.615 will help ensure that operators of Type B gathering lines have in place a robust framework for proactive measures to mitigate the public consequences of any emergency on their system.

PHMSA determined that extending these emergency planning requirements in § 192.615 to Type B gathering pipelines will also improve public awareness of pipeline safety and emergency response to incidents on Type B gathering pipelines, bringing requirements for such pipelines in line with existing requirements for all other part 192-regulated gas pipelines. Effective emergency response requirements are critical to help ensure the safety of the public, emergency responders, and operator personnel during gas pipeline emergencies on Type B gathering lines, which are located in Class 2, 3, and 4 locations.[426] Section 192.615 includes requirements to help ensure effective emergency preparedness, including a coordinated operator and community response to pipeline emergencies. Moreover, this requirement will help ensure

[426] Type B gathering pipelines are defined in § 192.8 as those gathering pipelines located in Class 4, Class 3, and certain Class 2 locations with the operating characteristics specified in Table 1 to § 192.8(c)(2).

that operators of Type B gathering lines are prepared to take appropriate immediate and continuous actions in response to a grade 1 leak, which could require activation of an emergency response plan.

Pressure Relief Devices

In this final rule, operators of Type A, Type B, Type C, and offshore gathering lines are required to comply with new requirements for the design and maintenance of pressure relief devices (§§ 192.199 and 192.739 in the final rule, respectively). Just like with gas transmission lines, inadequate design or configuration of pressure relief devices can cause significant, avoidable emissions when a relief device opens when it is not supposed to or, even worse, causes an incident when it fails to release gas when intended and fails to provide overpressure protection. Similarly, timely repair of a pressure relief device helps ensure that unnecessary releases are minimized, and unsafe conditions are corrected as soon as practicable. These requirements are discussed in further detail in section III.N.

Regarding comments concerned about the applicability of §§ 192.199 and 192.739 to pipelines existing prior to the establishment of regulatory standards for Type C regulated gathering lines, the design requirements in § 192.199 are non-retroactive and therefore only apply to Type C gathering lines that are newly constructed, replaced, relocated, or otherwise changed after the effective date of this final rule. While § 192.739 is in a retroactive subpart, and operators are required to maintain pressure relief devices that exist in accordance with these new requirements, it alone does not require an operator to install a pressure relief device if one is not present.

Offshore, Type A, Type B, and Type C gathering line operators are required to comply with the amended requirements for the maintenance of pressure relief devices in § 192.739(c). While operators of Type B and Type C gas gathering lines are not required to periodically inspect pressure relief and limiting devices in accordance with § 192.739(a) and (b), any malfunctions that are found by other means, including but not limited to leakage surveys, patrols, and investigations of incidents, must be maintained, and documented in accordance with the new requirements in § 192.739(c) and (d).

Compliance Timelines

In general, the requirements in this final rule applicable to regulated gas gathering lines are subject to the same compliance timelines in this final rule as other pipeline facilities. PHMSA believes this address concerns raised in public comments about the practicability of implementing all of the proposed requirements prior to the effective date as was proposed in the NPRM. Consistent with the GPAC recommendation on the issue, the compliance deadline for this final rule is January 1, 2028, for most requirements, and **[insert date 18 months after the date of publication of the final rule]** for the development of ALDP programs. These dates are discussed in greater detail in section III.U, and most of these compliance dates are listed in Table 1 to § 192.703. For regulated gathering lines, PHMSA has clarified in § 192.9(g) that the general compliance timelines listed in § 192.703(f) apply to regulated gas gathering lines subject to the requirements listed in that section. PHMSA has also clarified in this final rule that the compliance date for beginning right-of-way patrols on Type B and Type C gathering lines is January 1, 2028. Additionally, the compliance deadlines for operators of Type B and Type C gathering lines to prepare procedure manuals that fully meet the requirements of §§ 192.9 and 192.605(a) and for operators of Type B gathering lines to develop emergency plans is **[insert date 18 months after the date of publication of the final rule]**; compliance with those plans is subsequently required beginning January 1, 2028. The January 1, 2028, compliance deadline and the 18-month post-publication compliance deadline for the initial preparation of these plans and procedures is consistent with the GPAC-recommended timelines for these provisions and align with recommendations for reasonable compliance timelines in public comments PHMSA received.

While full compliance with the procedure manual requirements is not required until January 1, 2028, PHMSA cautions that the extended compliance date does not absolve operators of their existing obligations to document compliance with the previously existing requirements in § 192.9, including having and following plans and programs when such programs are explicitly required (e.g., damage prevention and public awareness), or compliance with the self-executing requirements in section 114 of the PIPES Act of 2020 at 49 U.S.C. 60108.

National Pipeline Mapping System

This final rule does not adopt the NPRM's proposal to require operators of regulated gas gathering line submit geospatial information to PHMSA as part of the NPMS requirements in § 191.29. While many gathering line operators do maintain geospatial information, such as the mapping information that was helpfully provided during the March 2024 GPAC meeting, and the majority of Type C gathering line mileage is owned by operators of onshore gas transmission lines that are required to comply with NPMS requirements, PHMSA acknowledges that establishing a GIS program and collecting geospatial information is not an insignificant effort for smaller regulated gas gathering operators who don't have GIS programs in place. PHMSA has determined that deferring the proposed GIS reporting requirements will allow regulated gas gathering line operators to focus on the important safety and environmental protection requirements in this final rule and the 2021 Safety of Gas Gathering Lines Final Rule. Additionally, PHMSA believes that implementing the other safety requirements in this final rule first will make it more practicable in the future for regulated gas gathering line operators to establish GIS programs and collect GIS information, since operators will have the opportunity to collect centerline data and other GIS information opportunistically over time as they perform the patrols, leakage surveys, and leak repairs required by this final rule. While this final rule ultimately does not adopt changes to the NPMS requirements, PHMSA will continue to evaluate regulated gas gathering NPMS participation in light of the public comments PHMSA received.

Other Comments

PHMSA appreciated the public comments concerned about the safety of Type R gathering lines and the applicability of safety requirements for Type R gathering lines. Since PHMSA did not propose to revise the definition of a regulated gas gathering line, nor propose in the NPRM that operators of Type R gathering lines to comply with specific part 192 requirements, imposing additional safety requirements for such pipelines are outside of the scope of this final rule. Nevertheless, PHMSA will take these comments into consideration when PHMSA evaluates the definition of a regulated gas gathering line or requirements for currently unregulated Type R gathering lines in the future.

As described in section III.K, in this final rule, PHMSA has withdrawn the proposed revisions to the OQ requirements as they relate to leak detection and repair activities. Withdrawing these provisions proposed at § 192.769 from this final rule should resolve concerns raised by commenters about the impacts of these revisions to Type A gathering lines subject to subpart N.

Regarding recordkeeping, PHMSA has revised the recordkeeping requirements related to leak repairs in § 192.760 to reference § 192.709 for gas transmission line repairs. As noted in the discussion of recordkeeping requirements in section III.J, while operators of Type B and Type C gathering lines are not subject to § 192.709 in general, they may use the record retention schedules described in that section for the purpose of meeting the recordkeeping requirements for leak repairs in § 192.760(j), which is required for all regulated gas gathering lines. This change allows a shorter record retention schedule for repairs to components other than pipe than would otherwise be permitted. Similarly, § 192.739 adopts recordkeeping requirements for repair of pressure relief devices. PHMSA did not propose overarching recordkeeping requirements for Type B and Type C regulated gas gathering lines but will consider the concerns raised by NAPSR when PHMSA evaluated the requirements for regulated gas gathering lines in the future.

The proposed rule did not address the scope of subpart N to part 192 or part 199, and neither §§ 192.760 nor 192.763 address the scope of subpart N or part 199 as proposed or as adopted in this Final Rule. Section 192.769, which has been removed in this final rule, proposed to clarify what activities were "covered tasks" for operators subject to subpart N, however it did not change the scope of OQ generally, and PHMSA did not propose to require operators of Type B and Type C gathering lines comply with § 192.769.

Q. Requirements for Pipelines Transporting Hydrogen

1. Summary of PHMSA's Proposal

As discussed in the NPRM, PHMSA's proposals were developed to apply generally to pipeline transportation of any "gas," including as defined in §§ 191.3 and 192.3 to mean "natural gas, flammable gas, or gas which is toxic or corrosive."[427] This would include, but is not limited to, the transportation of hydrogen gas and blends of hydrogen gas and natural gas. Unless otherwise specified in the proposed amendments, the NPRM proposed to apply the same requirements to hydrogen gas pipelines (and other gas pipelines) as to natural gas pipelines. While operators have decades of experience with pipelines transporting traditional hydrocarbon fuels, and many types of commercially available leak detection devices such as FIDs and CGIs can detect a range of hydrocarbons, transportation of hydrogen gas by pipeline is comparatively rare and may require different detection equipment. In the NPRM, PHMSA invited comment on whether, within a final rule in this proceeding, there would be value in adopting hydrogen gas pipeline-specific provisions in lieu of, or in addition to, the provisions proposed in the NPRM.

Regarding proposals specific to hydrogen gas in the NPRM, in the leak grading criteria at § 192.760(c), PHMSA proposed that grade 2 would be the minimum priority grade for leaks of gaseous hydrogen. This minimum grading priority was intended to apply to transported gaseous

[427] Gas, as defined at §§ 191.3 and 192.3, also includes liquified petroleum gas (LPG), landfill gas, synthetic gas, ethylene, propane, among other gases meeting that definition.

hydrogen, whether the hydrogen gas was transported by itself as a commodity or blended into a gas pipeline transporting a blend of hydrogen gas and natural gas.

PHMSA also proposed that, to the extent that the proposed requirements for the ALDP standard at § 192.763 were not appropriate for pipelines transporting gaseous hydrogen, operators could follow the requirements at § 192.763(c) to determine and follow an alternative ALDP performance standard appropriate for their transported commodity.

2. Summary of Public Comments

PHMSA received comments on the NPRM, as discussed throughout this document, that were not specific to hydrogen gas or blends of hydrogen gas and natural gas but equally applied to hydrogen gas or blends of hydrogen gas and natural gas. Unless otherwise specified in this document, this final rule applies the same requirements to hydrogen gas pipelines (and other gas pipelines) as to natural gas pipelines. The discussion below is focused on hydrogen-specific comments, Committee deliberation and recommendations, and PHMSA's response to such.

General Applicability

The Texas Chemical Council suggested that the reduction of hydrogen gas emissions is not part of the congressional mandate in sections 113 and 114 of the PIPES Act of 2020. Sanders Resources stated that hydrogen gas is not a greenhouse gas, and that the EPA has the jurisdiction and mandate to protect the environment. The Joint Environmental comment suggested that hydrogen acts as an indirect greenhouse gas and its emissions to the atmosphere contribute to near-term warming of our climate. They further stated that the NPRM did not provide adequate support for why the general "gas" pipeline standards, which are tailored to natural gas pipelines, are appropriate for hydrogen pipelines. They suggested that PHMSA should complete this rulemaking in a timely manner and commit to a near-term timeline to conduct a subsequent rulemaking focused on the safety of the transportation of hydrogen.

Similarly, the Attorneys General for NY et. al urged PHMSA to develop regulations specific to hydrogen pipelines, either in this rulemaking or in a future rulemaking. They further stated that, if PHMSA were to seek a future rulemaking on hydrogen, PHMSA should publish interim guidance that would ensure a higher level of care regarding hydrogen-specific pipelines and pipelines carrying hydrogen-methane blends. Several other groups and individual commenters (Interfaith Center on Corporate Responsibility, PST) encouraged PHMSA to undertake a future rulemaking with a specific focus on hydrogen pipelines and storage facilities.

Air Liquide Large Industries U.S. L.P. stated that ASME is transitioning the hydrogen pipeline standard, ASME B31.12,[428] to ASME B31.8,[429] and ASME B31.3,[430] the existing pipeline safety standards for gas pipelines and plant piping. They encouraged PHMSA to be patient in promulgating hydrogen pipeline regulations by letting the international technical experts develop additional and necessary language in ASME B31.8 for hydrogen pipelines, which, according to Air Liquide Large Industries U.S. L.P., will be completed and published by the end of 2024.

[428] ASME B31.12, "Hydrogen Piping and Pipelines" (2023)
[429] ASME B31.8, "Gas Transmission and Distribution Piping Systems" (2022)
[430] ASME B31.3, "Process Piping" (2022)

ALDP Performance Standard

Multiple operators and industry trade groups said that the proposed leak detection capabilities within the ALDP provisions were not appropriate for hydrogen gas pipelines, with one operator (Air Products) and an industry trade group (CHFC) specifying that the detection capability required by PHMSA's proposal is only available for handheld hydrogen gas detectors and not for remote hydrogen gas detectors. The Clean Hydrogen Future Coalition supported the position of the Industry Trades and provided an example of how the ALDP performance standard is not appropriate for hydrogen gas, noting specifically that remote optical techniques have not been developed for hydrogen leak detection because, unlike methane, hydrogen gas does not have an easily exploitable optical transition (e.g., hydrogen is not as easily detected as methane using remote optical techniques because of the different physical and chemical properties between the two gases). They further stated that there is not currently a reliable remote sensing option that can be performed by satellite, aircraft, or vehicles, or even an option that could be performed a few yards away from the air sample of interest, and the options that do exist for enclosed environments have capabilities in the 15-ppm sensitivity range.[431] The Industry Trades and Exxon Mobil also suggested that there are limitations in hydrogen sensor technologies, which require further research and development before pipeline operators can effectively implement these technologies as part of an effective, practical, hydrogen leak detection and

[431] See NPRM discussion in Section IV.B.1 (89 FR 31933). Methane leak detection technology can be sensitive to 1 ppm of methane, or below.

repair program. Heath Consultants Incorporated commented that leak detection equipment is available for hydrogen gas with sensitivity as low as 1 ppm.

The Joint Environmental comment and the PST also recognized that hydrogen leak detection equipment needs to improve and that PHMSA should fund research and engage in additional rulemaking for hydrogen pipelines after such research is complete. The Joint Environmental comment and PST suggested that PHMSA should require operators of hydrogen and other non-methane gas pipelines to follow the alternative ALDP standard at proposed § 192.763(c). The Clean Hydrogen Future Coalition supported PHMSA continuing to fund research and development efforts focused on evaluating hydrogen leak detection technologies but also recommended PHMSA defer applying all elements of the NPRM to pure hydrogen gas pipelines because they stated the proposed ALDP performance standard is not technically feasible, practicable, reasonable, or cost-effective for pipelines transporting pure hydrogen. Similarly, other industry commenters (the Industry Trades, Exxon Mobil, and Asset Leadership Network) supported PHMSA delaying the hydrogen aspects of the proposal.

Leakage Surveys

GTI Energy expressed general concern that the proposed intervals for leak surveys and patrols and leak grades for hydrogen pipelines were inconsistent with those recommended in ASME B31.12-2019 "Hydrogen Piping and Pipelines," and they suggested PHMSA review the differences to ensure consistency. Air Liquide Large Industries U.S. L.P. commented that PHMSA should not be limiting leak detection equipment to "handheld equipment" when pinpointing leaks, reasoning that new technologies may be developed that are not currently contemplated. Air Liquide Large Industries U.S. L.P. provided an example of a drone-based hydrogen detection system that may be more effective than any handheld device currently available for hydrogen detection. The Joint Environmental comment questioned the understanding of the level of hydrogen leakage from pipelines and other infrastructure and the effectiveness of existing leakage survey practices for hydrogen pipelines.

Leak Grading Criteria

Several commenters (Industry Trades, CHFC, Xcel Energy, and the Texas Chemical Council) suggested that the proposal to grade all leakages of hydrogen at no less than grade 2 is not supported by available literature. Regarding the proposal applicable to blends of hydrogen gas and natural gas, several operators suggested that classifying hydrogen leaks with grade 2 as the minimum priority grade may not be necessary when transporting low blends of hydrogen (e.g., under 10 percent volume). Further, they suggested that PHMSA should allow operators to grade leaks on pipelines transporting low-percentage blends of hydrogen as grade 3 leaks. One operator (Xcel Energy) supported PHMSA not allowing operators to classify leaks on pipelines transporting pure hydrogen as grade 3 leaks if PHMSA clarified that exclusion in the final rule. The Joint Environmental comment supported PHMSA requiring a grade 2 minimum for leaks of gaseous hydrogen. NAPSR questioned how other gases, such as chlorine gas, would meet the ALDP performance standard. The Texas Pipeline Association noted that the use of hydrogen transported in dedicated hydrogen pipelines has significant lifecycle benefits to the environment, which could be negatively impacted by excessive compliance costs for hydrogen pipelines with lower margins.

Reporting

PHMSA received several comments about the need for more transparency, through additional reporting requirements, for operators that transport blends of hydrogen gas and natural gas in gas pipelines. The additional reporting requirements suggested by commenters included operators notifying PHMSA of their intent to blend hydrogen gas into a natural gas pipeline in advance of blending, of commencement of blending operations, and of the average annual blend percentage for pipeline segments transporting blends. The Joint Environmental comment supported applying these additional reporting requirements to the mixture of any other gas into a natural gas pipeline exceeding a 1 percent blend rate, whereas the PST supported a reporting threshold of a 2 percent blend rate for hydrogen. H2 Clipper Inc. supported expanded reporting for the transportation of hydrogen, noting its increased flammability, greater propensity to leak, lower combustion level, and heightened public concern.

PRIA

Clean Hydrogen Future Coalition stated that the NPRM did not explain why the proposed standard would be workable for unblended hydrogen pipelines, nor did the PRIA analyze the costs and benefits of applying the proposed standard to such pipelines.

3. GPAC Deliberation Summary

The Committee discussion of the NPRM proposals for hydrogen gas and blends of hydrogen gas and natural gas occurred on Monday and Tuesday, March 25 and 26, 2024, respectively, within a broader discussion of all proposed requirements for facilities transporting hydrogen gas and blends of hydrogen gas and natural gas and LNG facilities. During a summary presentation by PHMSA, the agency restated that the leakage survey, patrol, and repair requirements in the proposed rule would apply to hydrogen pipelines (including pipelines transporting blends of hydrogen gas and natural gas). PHMSA further noted the NPRM included a requirement that leaks of hydrogen gas be considered no less than grade 2 leaks, and flexibility for pipelines transporting hydrogen gas – either as a pure commodity or within a blend of predominantly natural gas – through eligibility for the alternative leak detection performance standard described in proposed § 192.763(c). PHMSA summarized the submitted written public comments and requested Committee discussion on the proposal as it applies only to pipelines transporting pure hydrogen gas. Additionally, PHMSA noted comments from a variety of stakeholders, including public, regulatory, and industry representatives, supporting the need for new reporting requirements and more transparency for pipelines transporting blends of hydrogen and natural gas.

The Committee then heard comments from the public present at the meeting, representing operators, technology providers, and public advocacy groups, that the technology to detect hydrogen leaks is not as capable as the equipment used for detecting leaks of methane. The Committee also heard varied suggested paths forward; the first being that the application of the rule should exclude hydrogen gas; and the second that operators of hydrogen gas pipelines should be required to pursue and use the alternative ALDP performance standard. Despite those differing opinions, commenters generally agreed that a future rulemaking, focused on pipelines transporting hydrogen gas and blends of hydrogen gas and natural gas, would be appropriate.

The Committee then discussed at length their thoughts regarding hydrogen pipelines, including a discussion of the physical and chemical property differences between methane and hydrogen, distinctions that could be drawn between a dedicated (or pure) hydrogen pipeline and a pipeline that is a blend of hydrogen gas and hydrogen gas, and the effectiveness and technical feasibility of the proposed leak detection tools as applied to dedicated hydrogen pipelines and blends of hydrogen gas and natural gas. Some Committee members representing industry expressed concerns with the proposed leak detection thresholds and tools, noting that methane and hydrogen are different such that standards developed and recommended by the committee with a focus on methane do not apply to hydrogen gas. The Committee generally acknowledged that the standards proposed in the NPRM were focused on methane, with some Committee members representing the public suggesting that the proposal included sufficient flexibility for hydrogen gas through the alternative ALDP methods proposed at § 192.763(c). The Committee discussed that the expansion of hydrogen-based infrastructure was likely and that appropriate requirements are necessary for that sector to continue to operate safely.

The Committee also discussed the safety and integrity risks posed by pure hydrogen and blends of hydrogen gas and natural gas in gas pipelines, namely hydrogen cracking, embrittlement, corrosion, and a greater likelihood of leaks due to the smaller physical size of hydrogen molecules compared to methane. The Committee came to consensus that pipelines transporting blends of hydrogen gas and natural gas are doing so at relatively small percentages (i.e., less than 10 percent hydrogen gas, by volume). A Committee member representing the public recommended that PHMSA adopt leak detection standards for hydrogen pipelines due to the likelihood of a future buildout of hydrogen pipelines to ensure that current safety risks are being addressed while undertaking studies of the unique characteristics of hydrogen gas and blends of hydrogen gas and natural gas in anticipation of a future rulemaking. In discussing the differences between hydrogen pipelines and blended pipelines, and limitations of existing leak detection technology, an industry member stated that as long as the pipeline commodity was at least 50 percent methane, the current leak detection technology and tools would be effective. Committee members representing the public suggested that the alternative ALDP method proposed by PHMSA was adequate to handle the different technology that may be necessary to implement a leak detection and repair program for hydrogen pipelines. They continued by elaborating on the existing available technology that could be used to detect leaks on hydrogen pipelines. The Committee discussion ultimately led to providing recommendations separately for pure hydrogen gas pipelines and blended hydrogen gas and natural gas pipelines. The Committee discussed and came to a general agreement that pure (i.e., dedicated) hydrogen pipelines were those that were predominantly hydrogen gas, with a hydrogen content of more than 50 percent, by volume, recognizing that hydrogen content in these pipelines is often much closer to 100 percent hydrogen gas, by volume, with few impurities. Regarding blends of hydrogen gas and natural gas, the Committee agreed that widespread, hydrogen blending was not occurring beyond a limited number of distribution systems, and that even then, the practice involved small (less than 10 percent hydrogen gas, by volume) injections of hydrogen gas.

Throughout the conversation, the Committee remained divided regarding the application of the proposed rule as it should apply to pure hydrogen pipelines; however, the Committee generally supported further research through a study intended to address integrity issues and leak management practices for pipelines transporting pure hydrogen gas and blends of hydrogen gas and natural gas. Further, some Committee members expressed comments consistent with agreement that the proposed rule should apply to blends of hydrogen gas and natural gas when the pipeline was predominantly natural gas, with a small minority of Committee members representing the public disagreeing that the proposals should be limited to predominantly natural gas pipelines as they were discussed by the Committee. Some Committee members suggested that PHMSA should include specific standards for these blends in a final rule.

4. GPAC Recommendation

As discussed in greater detail above, the Committee discussed the appropriateness of the requirements as they would apply to both the transportation of hydrogen gas and blends of hydrogen gas and natural gas. The Committee recommended that PHMSA apply the requirements proposed for natural gas pipelines to blends of natural gas and hydrogen where natural gas is the predominant constituent. The Committee also recommended that PHMSA initiate a study of integrity issues and leak management practices for pipelines transporting hydrogen gas and blends of natural gas and hydrogen.

While the GPAC deliberated on the applicability of the final rule with respect to dedicated hydrogen pipelines (i.e., pipelines transporting predominantly hydrogen gas), the committee was unable to reach agreement on this topic. A member proposed the following recommendations for dedicated hydrogen pipelines, but the 5-8 vote on the motion was unsuccessful:

- Proposed leak detection and repair standards apply.
- PHMSA consider alternative measures relevant to dedicated hydrogen pipelines, including applying the alternative ALDP performance standard as the default performance standard for such pipelines.

5. PHMSA Response

PHMSA appreciates the comments and concerns regarding the applicability of this rule—which is generally focused on the transportation of natural gas—to the transportation of hydrogen gas. As discussed in the section above, the Committee discussed the appropriateness of the proposed requirements as they would apply to both the transportation of hydrogen gas and blends of hydrogen gas and natural gas. PHMSA acknowledges and understands the concerns raised by the public comments and the recommendations made by the Committee. PHMSA believes that certain changes, as they relate to the applicability of the final rule to pipelines transporting hydrogen gas, are necessary for the final rule.

In the Committee discussion and vote regarding dedicated hydrogen pipelines, various terms were used to describe what was voted on as dedicated hydrogen pipelines (predominantly hydrogen gas). During the Committee discussion, additional terms such as "pure hydrogen" and "unblended hydrogen" pipelines were used interchangeably to refer to dedicated hydrogen pipelines. These terms were used by the Committee and public commenters to identify these hydrogen pipelines for purposes of discussing the applicability of the proposed rule, but also to differentiate these dedicated hydrogen gas pipelines from pipelines transporting a blend of hydrogen gas and natural gas, which were discussed separately by the Committee and are discussed separately in this final rule.

The Pipeline Safety Regulations do not currently define what percentage by volume constitutes a hydrogen gas pipeline, nor do they define the term "predominant;" however PHMSA's annual reports have requested operators report the volume of commodity transported and type of commodity transported for hydrogen gas pipelines since 2010 without issue.[432] In prior rulemakings, PHMSA agreed with industry interpretation that the term predominant means "more than half" in certain contexts.[433] Predominant is also defined by Merriam-Webster as "being most frequent or common."[434] In addition, industry standard ASME B31.12-2019 for the transportation of hydrogen gas excludes hydrogen gas with a hydrogen content less than 10 percent by volume.[435] As is discussed in greater detail below, PHMSA published a 60-day notice for a proposed information collection for gas pipelines transporting blends of hydrogen gas and natural gas.[436] In that information collection, PHMSA proposes to collect three new categories of commodity transported based on hydrogen content: (1) greater than zero percent but less than or equal to five percent; (2) greater than five percent but less than 20 percent; and (3) greater than

[432] PHMSA, 75 FR 72878, "Pipeline Safety: Updates to Pipeline and Liquefied Natural Gas Reporting Requirements". (November 26, 2010)

[433] RSPA, 54 FR 41912, "Transportation of Carbon Dioxide by Pipeline," (October 12, 1989).

[434] Merriam-Webster, "predominant", merriam-webster.com/dictionary/predominant, (last accessed August 23, 2024).

[435] ASME, ASME B31.12-2019, "Hydrogen Piping and Pipelines," Section PL-1.3.

[436] See 89 FR 20751; PHMSA; "Pipeline Safety: Information Collection Activities: Mitigation of Ruptures on Onshore Gas Transmission and Gathering, Hazardous Liquid, and Carbon Dioxide Pipeline Segments Using Rupture-Mitigation Valves or Alternative Equivalent Technologies and Blending of Hydrogen Gas and Natural Gas Within Gas Pipelines." Docket No. PHMSA-2022-0085.

or equal to 20 percent. PHMSA is unaware of any gas transmission or gas distribution pipelines that are currently transporting, or are planning to transport in the future, a blend of hydrogen gas and natural gas in which the hydrogen content, by volume, exceeds 50 percent.[437,438] Similarly, PHMSA is unaware of any gas transmission or gas distribution pipelines that are currently transporting, or are planning to transport in the future, a gas mixture that is hydrogen gas mixed with any other gas (such as natural gas), in which the hydrogen gas content, by volume, is less than 90 percent. In either case, and for all possible blends in between, PHMSA would expect such pipelines to be regulated under part 192 since a mixture of hydrogen and methane or any other regulated gas would be a "gas" within the meaning of § 192.3.

For the purposes of this final rule and its applicability to certain pipelines transporting various amounts (quantified by percentage by volume) of hydrogen gas, PHMSA intends to, consistent with Committee deliberations and recommendations, revise this final rule to eliminate provisions applicable to the transportation of gas containing more than 50 percent of hydrogen gas, by volume, related to the applicability of the requirements for leak grading and repair, and the ALDP performance standard and exempted by §§ 192.703(e) and 192.760, 192.706(a)(2), and 192.763(e), respectively. Unless otherwise specified throughout this document, this final rule

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[437] Outside of blending demonstration projects, the highest observed concentration of hydrogen gas being transported in part 192-regulated gas transmission or gas distribution pipelines of which PHMSA is aware is in a synthetic gas mixture transported by distribution pipelines operated by Hawai'i Gas. During its operating history, a town gas mixture containing up to 50 percent hydrogen by volume was transported. However, more recent mixtures transported in that system contain up to 15 percent hydrogen by volume. See https://www.hawaiigas.com/clean-energy/decarbonization (last accessed Aug. 23, 2024).

[438] Topolski et al, "Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology," National Renewable Energy Laboratory, (October 2022); NREL/TP5400-81704. https://www.nrel.gov/docs/fy23osti/81704.pdf.

applies the same requirements to hydrogen gas pipelines as to natural gas pipelines. The applicability of this final rule, unless noted otherwise, includes blends of hydrogen gas and natural gas in natural gas pipelines as such pipelines are "predominantly" natural gas, having a natural gas content, by volume, of at least 50 percent.

At the time of drafting this final rule, PHMSA is funding 11 research and development projects related to the transportation of hydrogen gas and blends of hydrogen gas and natural gas. These projects include research into threat prevention (e.g., Development of Compatibility Assessment Model for Existing Pipelines for Handling Hydrogen-Containing Natural Gas),[439] anomaly detection and characterization (e.g., Investigate Damage Mechanisms for Hydrogen and Hydrogen/Natural Gas Blends to Determine Inspection Intervals for In-Line Inspection Tools),[440] materials (e.g., Determining Steel Weld Qualification and Performance for Hydrogen Pipelines),[441] leak detection (e.g., Advancing Hydrogen Leak Detection and Quantification Technologies Compatible with Hydrogen Blends),[442] climate change impacts, and underground gas storage. Information regarding PHMSA's funded research and development projects is

[439] University of Oklahoma, primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=988&s=67A5F5F507F84C8DB98E603F2B89C2C4&c=1 (last accessed Sept. 5, 2024).

[440] Kiefner and Associates, Inc., https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=1009&s=67A5F5F507F84C8DB98E603F2B89C2C4&c=1 (last accessed Sept. 5, 2024).

[441] National Institute of Standards and Technology, primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=976&s=67A5F5F507F84C8DB98E603F2B89C2C4&c=1 (last accessed Sept. 5, 2024).

[442] Gas Technology Institute, https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=979&s=67A5F5F507F84C8DB98E603F2B89C2C4&c=1 (last accessed Sept. 5, 2024).

available online at PHMSA's website for Research and Development Program Awards (https://primis.phmsa.dot.gov/matrix/).

Regarding comments urging PHMSA to pursue a separate rulemaking related to the transportation of hydrogen gas, PHMSA understands and appreciates these comments. As conveyed in the NPRM, PHMSA saw the need for, and sought applicability of, the proposed requirements to the transportation of hydrogen gas for more than 1,600 miles of hydrogen pipelines.[443] PHMSA recognized, however, by including a request for comments at 88 FR 31926, that PHMSA is better served by gathering additional information from the public and industry on the topic and performing additional research. PHMSA also acknowledges ongoing work by ASME and industry stakeholders—including PHMSA—to update ASME pipeline standards to include additional and necessary requirements for hydrogen pipelines. PHMSA is committed to ensuring that operators safely transport hydrogen gas and will consider hydrogen-specific requirements in future rulemakings.

Regarding the application of the ALDP standard to hydrogen pipelines, PHMSA agrees with the Committee discussion and the majority of the commenters, as described above, that the proposed ALDP performance standard is not appropriate for dedicated hydrogen gas pipelines.[444] The requirements for the ALDP standard proposed in the NPRM were developed to primarily address the environmental harm and public safety risks posed by the release and leakage of

[443] PHMSA, "Gas Distribution, Gas Gathering, Gas Transmission, Hazardous Liquids, Liquefied Natural Gas (LNG), and Underground Natural Gas Storage (UNGS) Annual Report Data," https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.

[444] Several Committee members supported the application of the ALDP requirements to hydrogen pipelines through the alternative ALDP performance standard at proposed § 192.763(c), as proposed in the NPRM.

methane.[445] Despite that focus, PHMSA intended for the rule, unless otherwise specified in the proposed amendments, to apply the same requirements to hydrogen gas pipelines (and other gas pipelines) as to natural gas pipelines.[446] As discussed previously in this section III.Q, the NPRM included consideration for hydrogen in terms of the definition of the lower explosive limit, the proposal at § 192.760(c) to require all hydrogen leaks to be either grade 1 or 2, and allowing operators of any part 192-regulated pipeline facility transporting flammable, toxic, or corrosive gas other than natural gas (e.g., hydrogen gas) to seek PHMSA review and use of an alternative ALDP performance standard better suited for the transported commodity. However, the NPRM did not provide any additional detail or specificity for hydrogen gas. PHMSA was compelled by the Committee discussion and the resulting vote on dedicated hydrogen pipelines. PHMSA believes that dedicated hydrogen pipelines warrant the same rigorous discussion and development of an ALDP performance standard as was developed for methane in this rulemaking, and that a future rulemaking focused on hydrogen is necessary to develop commensurate standards. Accordingly, PHMSA is revising the final rule in § 192.763 to include an exception at § 192.763(e) that will exempt hydrogen gas pipelines (i.e., a pipeline facility transporting gas containing more than 50 percent of hydrogen gas by volume) from having to comply with the ALDP performance standard at § 192.763. However, PHMSA is making a conforming change at § 192.706(a)(2) to require that operators must still perform leakage

[445] 88 FR 31890 at p. 31933. The "proposed 5 ppm [leak detection] performance standard balances each of the following: a methane sensitivity threshold consistent with the performance of state-of-the-art, commercially-available technologies; robust margin to risk of ignition; and flexibility for operators to choose from a baseline of high-quality equipment for their unique needs."

[446] 88 FR 31890 at p. 31926.

surveys on these ALDP-exempted pipelines using leak detection equipment, but that leak detection equipment need not meet the requirements of § 192.763.

PHMSA agrees with the Committee recommendation that the rule, as proposed, including the advanced leak detection performance standard at § 192.763, is appropriate and applicable to pipelines transporting natural gas blended with hydrogen gas, but not to dedicated hydrogen pipelines, as discussed in the previous paragraph. As noted above, PHMSA is unaware of plans to transport natural gas blended with hydrogen with a natural gas content less than 90 percent by volume. For such gas blends with low hydrogen content by volume, operators can detect and grade emissions using equipment capable of detecting natural gas. PHMSA expects operators transporting these blends, which are predominantly composed of methane, to evaluate the impact any amount of hydrogen gas being transported has on the requirements of this final rule. For instance, PHMSA expects operators to understand the effects of hydrogen gas on the ability of leak detection equipment to detect leaks of both hydrogen gas and natural gas under the requirements of § 192.763(b). By way of an additional example, in a pipeline transporting a blend of hydrogen gas and natural gas, PHMSA expects operators to account for the presence and unique characteristics of each gas being transported (i.e., both hydrogen and methane) when grading leaks in accordance with the requirements at § 192.760. If other gases are present in transported volumes that present unique characteristics or different hazards (e.g., toxicity, flammability, asphyxiation, etc.) than the predominant commodity, PHMSA expects to see operators consider commodity-specific elements in their leakage survey investigation and grading procedures. Operators should also consider developing and using an alternative ALDP performance standard according to the requirements at § 192.763(d), as needed and appropriate for the products transported. For pipelines transporting blends of hydrogen gas and natural gas, as the percentage of hydrogen gas increases, the risks of flammability, permeability, and explosivity due to the increased hydrogen content start to outweigh those risks posed by natural gas alone.[447] Therefore, the transportation of blends of hydrogen gas and natural gas with more than 5 percent, but not exceeding 20 percent, of hydrogen gas by volume, warrant operators consider hydrogen-specific elements in their leakage survey, leak grading, and leak detection procedures. Further, PHMSA recommends that operators transporting a blend of hydrogen gas and natural gas that contains more than 20 percent of hydrogen gas, by volume, should consider developing and using an alternative ALDP performance standard according to the requirements at § 192.763(d).

PHMSA appreciates comments from the industry and public supporting the need for more transparency for operators that transport blends of hydrogen gas and natural gas. PHMSA agrees with this need for additional information and proposed an information collection on March 25, 2024, to collect information from pipeline operators transporting blends of hydrogen gas and natural gas in gas pipelines.[448] This information collection intends to allow PHMSA to

[447] Topolski et al, "Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology," National Renewable Energy Laboratory, (October 2022); NREL/TP5400–81704. https://www.nrel.gov/docs/fy23osti/81704.pdf.

[448] See 89 FR 20751; PHMSA; "Pipeline Safety: Information Collection Activities: Mitigation of Ruptures on Onshore Gas Transmission and Gathering, Hazardous Liquid, and Carbon Dioxide Pipeline Segments Using Rupture-Mitigation Valves or Alternative Equivalent Technologies and Blending of Hydrogen Gas and Natural Gas Within Gas Pipelines." Docket No. PHMSA-2022-0085.

identify trends related to the blending of hydrogen gas and natural gas within gas pipelines from operator-submitted data.

Regarding the comments received regarding leakage surveys and an apparent lack of consistency with requirements for leakage surveys in industry standards for the transportation of hydrogen gas, when compared to the existing requirements in part 192 for leakage surveys at § 192.706, the NPRM expanded the locations where more frequent leakage surveys are required as described in Table 1 of § 192.706, which was proposed to be applicable to dedicated hydrogen pipelines as well as other gas pipelines, including blends of hydrogen gas and natural gas. This final rule retains a maximum interval of once per calendar year, but not to exceed 15 months, for all other transmission lines as described in Table 1 of § 192.706. In response to public comments regarding inconsistencies between the requirements in the NPRM and industry standards, the maximum 12-month interval between leakage surveys found in industry standard ASME B31.12-2019, which is not incorporated by reference, does not prevent an operator from determining that more frequent leakage surveys are appropriate for their system when considering the pipeline's operating pressure, hoop stress level, piping age, class location, and whether the commodity is odorized. Similarly, ASME B31.12-2019 also provides guidance on pipeline patrols, and an operator is allowed to select a more frequent patrolling interval than what is required in the Federal minimum requirements at § 192.705.

During Committee discussion of hydrogen and blends of hydrogen gas and natural gas, the Committee sought clarification from PHMSA regarding the intent of the grade 2 leak grading and repair criteria proposed at § 192.760(c)(1)(viii). PHMSA clarified during the meeting that the intent of that criterion, which was written as applying to "gaseous hydrogen," was intended to be applied to pipelines transporting predominantly hydrogen gas and not low-level blends of hydrogen gas and natural gas.

This final rule removes the proposed requirement to designate all leaks of hydrogen as grade 1 or grade 2 leaks at a minimum. While the leak grading and repair requirements, other than the legacy § 192.703(c) requirement to promptly repair certain leaks, do not apply to dedicated hydrogen pipelines (i.e., pipelines transporting a mixture predominantly composed of hydrogen gas by volume), the leak grading criteria would still apply to the pipelines transporting natural gas, including typical blends of hydrogen gas and natural gas in gas pipelines.[449] PHMSA agrees with the interpretation by commenters of the NREL report[450] cited in the preamble of the NPRM noting that, for low-percentage blends of hydrogen gas in natural gas pipelines, the explosive energy is substantially similar to natural gas, and therefore a default grade 2 requirement is not necessary for blends covered by the scope of the grading criteria PHMSA is finalizing in this rulemaking.

In this final rule, "dedicated hydrogen" pipelines (i.e., pipelines transporting gas mixture containing more than 50 percent hydrogen, by volume) are exempted from the leak grading and repair requirements under § 192.760, in accordance with the exemption at § 192.703(e). To the contrary, pipelines transporting blends of hydrogen gas and natural gas are required to comply

[449] See Section III.Q. PHMSA is exempting pipelines transporting gas containing more than 50 percent hydrogen, by volume, from the leak grading requirements of § 192.760.

[450] 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.

with the leak grading and repair requirements at § 192.760. However, PHMSA is amending proposed § 192.760(c)(1)(viii), which is renumbered in this final rule as § 192.760(c)(1)(x), to remove the requirement that any leak of hydrogen gas not otherwise qualified as a grade 1 leak be qualified as a grade 2 leak, consistent with the Committee discussion. This revision effectively allows operators of pipelines transporting blends of hydrogen gas and natural gas to grade leaks into the appropriate grade of any of the three leak grades. As discussed above in PHMSA's response to the ALDP performance standard as it applies to blends of hydrogen gas and natural gas, PHMSA expects operators of pipelines transporting these blends and other blends to consider, develop, and implement appropriate, analogous thresholds in their written procedures accounting for the possibility of both natural gas (i.e., methane), hydrogen gas, or any other gas being transported, when applying the leak grades at § 192.760.

Based on analysis in the final RIA, adopting the GPAC recommendation does not significantly affect the costs and benefits of the final rule. In the RIA, PHMSA evaluated two alternatives related to pipelines transporting hydrogen and hydrogen-blends: (1) limiting the application of the ALDP and performance standards to natural gas facilities only; and (2) adding additional, hydrogen-specific requirements. As discussed in the RIA, PHMSA's decision to exclude hydrogen pipelines from the ALDP requirements and performance standards will have a negligible effect on the total costs and benefits of the final rule, as the mileage of these pipelines is minimal when compared to the mileage of natural gas facilities, though the revised scope does lower costs and benefits for such systems. For hydrogen gas blends covered by the rule, detection and grading is based on the natural gas content and as noted above, blends rarely if ever contain more than 10 percent hydrogen. Therefore, the costs and benefits for leak detection and repair are equivalent to gas distribution and gas transmission lines transporting natural gas.

R. Definition of "Leak or Hazardous Leak"—192.3

1. Summary of PHMSA's Proposal

The NPRM included a definition for the term "leak or hazardous leak" in § 192.3. Additionally, based on language from the PIPES Act of 2020 that recognizes that leaks and releases of gas can be hazardous to both public safety and the environment, PHMSA proposed miscellaneous amendments to the rest of part 192 to clarify when existing references to the terms "hazard" or "hazardous" in part 192 referred to hazards to public safety, hazards to the environment, or both.

PHMSA proposed to define the term "leak or hazardous leak" 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. The proposed definition itself is addressed in greater detail in the discussion of definitions related to leak grading in section III.H. However, based on this proposed definition, PHMSA also proposed miscellaneous conforming changes to part 192 to address whether existing references to leaks referred solely to leaks hazardous to public safety or to leaks hazardous to the environment. Similarly, PHMSA proposed revisions to the part 191 annual report forms and instructions for gas transmission; offshore gathering; Type A, Type B, and Type C gathering pipelines (F 7100.2-1); Type R gathering pipelines (F 7100.2-3); and gas distribution pipelines (F 7100.1). These changes are described in section III.L and generally replace references to "hazardous leaks" with the leak grades PHMSA proposed in § 192.760. PHMSA proposed to exclude the IM regulations at subparts O and P from application of the new definition of "leak or hazardous leak" at § 192.3.

PHMSA also proposed to delete language throughout part 192 suggesting contingency (for example, references to "potentially hazardous" releases) at §§ 192.503(a)(2), 192.507(a), 192.509(a), 192.513(b), 192.553(a)(2), 192.557(b)(2), and 192.751(a)). Additionally, PHMSA proposed an editorial amendment to the DIMP performance measures requirements in § 192.1007 to remove cross-reference to § 192.703. Currently, § 192.1007 requires an operator to include as a performance measure "hazardous leaks either eliminated or repaired as required by § 192.703(c)." PHMSA separately proposed to replace reference to hazardous leaks in § 192.703 with the new grading criteria in § 192.760, rendering this cross-reference inaccurate.

PHMSA did not propose to expand every reference to "hazard" or "hazardous leak" in PHMSA's part 191 and 192 regulations to encompass environmental hazards. As noted above, PHMSA proposed to exclude the IM regulations at subparts O and P from application of the new definition of "leak or hazardous leak" at § 192.3. Additionally, PHMSA proposed revising other references to "hazards" to preserve those provisions' historical and appropriate focus on public safety, rather than environmental, hazards. Generally, those proposals added qualifying language (i.e., "hazard(s) to public safety") where an explicit reference to environmental hazards would either be unnecessary or unsuitable. PHMSA proposed these conforming amendments at §§ 191.23(a)(9), 192.167(a)(2), 192.169(b), 192.179(c), 192.199(e), 192.361(f)(3), 192.363(c), 192.629(a)-(b), 192.727(b)-(c) and 192.751.

2. Summary of Public Comments

Proposed definition of "leak or hazardous leak"

The PST noted that leaks contribute to public health, environmental, and climate risks and recommended that all leaks be considered hazardous, reasoning that any leak indicates a pipeline is functioning improperly. They further noted that even small leaks that have conventionally been considered "non-hazardous" can have major societal costs. Similarly, Citizens for a Healthy Community, a form letter campaign, Connecticut State Representative David Michel, and an individual commenter stated that all leaks should be considered dangerous and be repaired. The MD Attorney General et al. stated that all leaks present a danger to persons or property.

Multiple operators and the North Dakota Petroleum Council stated that leaks that may cause negligible future harm to the environment should not be evaluated at the same level of importance as leaks that might cause immediate harm to people or property, and that the proposed definition would strip the value and meaning of the "hazardous" designation. The Industry Trades, the City of Bowman, the Petroleum Alliance of Oklahoma, Northeast Gas Association, Texas Chemical Council, INGAA, GPA Midstream Association, et al., and the Alabama Natural Gas Association expressed concern that the NPRM treated all leaks as hazardous leaks for repair purposes regardless of the risk to public safety or the environment. Atmos Energy Corporation stated that GHG emissions do not fall within the definition of "hazard" or "hazardous" and that it would introduce unnecessary confusion to define such leaks as "hazardous."

GPA Midstream Association, et al., Marcellus Shale Coalition, Texas Chemical Council, INGAA, the Industry Trades, operators, and industry representatives urged PHMSA to include a distinction between "leak" and "hazardous leak." Multiple operators suggested three separate definitions for "leak," "hazardous leak," and "environmentally significant leak." The MD Attorney General et al. also suggested PHMSA define the terms separately. NAPSR suggested PHMSA create a separate definition of "leak" and adjust it to reflect the appropriate leak term and denote the level of urgency associated with the leak. Similarly, PPL Corporation stated the proposed change to the definition would create ambiguity when talking about leaks and suggested PHMSA create a different category for higher-emitting leaks.

NAPSR, GPTC, Northeast Gas Association, industry representatives, and the Industry Trades suggested PHMSA continue to use the definition for "hazardous leak" at § 192.1001 and incorporate that definition at § 192.3. Multiple operators and an individual commenter stated that only grade 1 leaks should be considered "hazardous." The Industry Trades and multiple operators suggested there be one clear definition of hazardous leaks, and that IM plans should not have a different definition for a hazardous leak.

The Industry Trades, INGAA, Northeast Gas Association, Texas Chemical Council, GPA Midstream Association, et al., multiple operators, and industry representatives stated that the proposed changes to the definition conflicted with the PIPES Act of 2020, longstanding regulatory precedent, the Pipeline Safety Act, and industry practice. NAPSR, the Industry Trades, GPTC, and Northeast Gas Association expressed concern with PHMSA combining the terms "leak" and "hazardous leak" into one definition, reasoning that the GPTC criteria and

Congress both have acknowledged certain leaks can be non-hazardous at the time of detection and in the future. The Industry Trades, GPA Midstream Association, et al., and Texas Chemical Council stated that, through exceptions to UNGSFs and transmission and distribution IM, PHMSA noted the proposed definition of "leak or hazardous leak" was not appropriate to apply throughout part 192. The Petroleum Alliance of Oklahoma suggested that PHMSA adjust the proposed definition to provide "practical terminology" that is consistent with the EPA's updated methane emissions new source performance standards.

Regarding the definition of leak, the Industry Trades, INGAA, Northeast Gas Association, and multiple operators suggested removing the provision that leaks could be identified or pinpointed through "touch," reasoning it would be potentially dangerous. The Industry Trades, INGAA, and multiple operators stated that releases from relief valves, emergency shutdown devices, and other unintended releases should not be included in PHMSA's leak repair and reporting criteria because they are not uncontrolled. Northeast Gas Association stated that PHMSA should replace the use of "uncontrolled" with "unintentional."

Corresponding changes regarding public safety and regarding contingency

The MD Attorney General et al. supported PHMSA proposing to delete references to "potentially hazardous" releases in part 192. GPA Midstream Association, et al. and Texas Chemical Council stated that PHMSA should omit phrases such as "existing, probable, or future" when hazards are referenced in part 192.

The GPTC opposed the proposal clarifying that requirements for locating the discharge point of vent piping at compressor stations for ESDs in § 192.167 and pressure limiting devices at § 192.169 referred to "hazards to public safety" rather than "hazards" more generically. They expressed concern that the use of "to public safety" in these requirements ignored environmental safety and stated that the existing language was sufficient. NAPSR supported these proposed changes.

The GPTC also opposed the proposal clarifying that that the relief device venting requirements in existing § 192.199(e) refer to "hazards to public safety," stating the change was unnecessary and that the existing regulatory language is sufficient. In addition, multiple individual operators stated that inserting "to public safety" at § 192.199(e) would be confusing, reasoning that this section already speaks in terms of "undue hazard."

Kentucky Oil and Gas Association opposed the proposal clarifying that references to hazards in the requirements for the location of the discharge of gas transmission blowdown valves in § 192.179(c) refer to hazards to public safety. They commented that this provision would require operators to purchase additional piping and bracing and install new alarms and warning systems, noting that this could add an additional $50,000 onto a pipeline project, which could render some projects not economically viable.

NAPSR suggested further revisions to the proposed pressure test requirements, commenting that the purpose of pressure testing was to find and eliminate all leaks, not just hazardous leaks, and suggested PHMSA adjust the regulatory language at §§ 192.503, 192.507, 192.509, and 192.513 to include all leaks. Conversely, the Industry Trades, INGAA, and an operator opposed the proposed clarification to pressure test requirements, commenting that GPTC guidance recognizes some allowable leakage during a pressure test, particularly for leaks on the pressure test header the operator uses to perform the pressure test rather than on the pipeline the operator will put into service. Multiple operators opposed the proposal to insert the proposed "leak or hazardous leak" definition in the upgrading requirements at §§ 192.553 and 192.557. The Marcellus Shale Coalition similarly suggested PHMSA retain the word "potentially" in reference to potentially hazardous leaks in the subpart J pressure testing requirements at §§ 192.503, 192.507, 192.509, and 192.513.

NAPSR supported the proposal clarifying that reference to hazards in the purging requirements at § 192.629 refer to hazards to public safety but requested PHMSA make an editorial amendment. Specifically, they recommended PHMSA revise the language to read, "Operators shall utilize purging procedures that minimize the release of natural gas and incorporate the use of modern reinjection technology if available and practical."

Cost considerations and annual report forms

Multiple operators stated that managing all detectable leaks as hazardous would be burdensome and extremely costly, particularly when reporting leaks that do not present a potential hazard to public safety during annual leak surveys. Operators stated that it would be impractical and shift resources away from necessary priorities to chase very small releases.

The Industry Trades expressed concern that the instructions in part C of the Gas Distribution Annual Report and part M of the Gas Transmission and Gas Gathering Annual Report uses a definition of leak that conflates "leaks" and "hazardous leaks." Northeast Gas Association and INGAA shared that PHMSA did not consider the impact conflating the definitions of leak and hazardous leak would have on tracking and trending of leak data and suggested any changes to the definitions of hazardous leaks must also be mirrored in the instructions for §§ 191.11 and 191.17 annual reports. Kinder Morgan, Inc. stated that the proposed definition of a leak would lead to an increase in the number of leaks reported, making it difficult to compare future data with data that existed prior to a final rule in this proceeding, and an increase in the burden associated with leak detection. KOGA stated the proposed change would create additional reporting and tracking requirements for operators. Williams Company Inc. stated that it is important for definitions in § 191.3 to be clear and accurate, as they are the foundation for reporting requirements. The commenter supported defining a leak.

Multiple operators stated that PHMSA's estimates of compliance burdens were far too low, and that the proposed definition change constituted a paradigm shift in the approach to pipeline regulation. GPA Midstream Association, et al, the Industry Trades, and Texas Chemical Council stated that PHMSA failed to conduct a risk assessment for the proposed definition change. The City of Monroe provided estimations of the costs associated with compliance with the proposed changes to "hazardous" leak management.

3. GPAC Deliberation Summary

The Committee discussed the proposed definition of "hazardous leak or leak" as requested by PHMSA. The Committee heard public comments on this proposed definition from representatives from Williams Companies, Inc., Rhode Island Energy, INGAA, and Southwest Gas. Public comments made during the proceeding stated that "not all leaks are hazardous to life or property and treating all leaks as hazardous to life or property dilutes the importance of a prompt response when there is an immediate risk to life or property." Public commenters during the proceeding also questioned "whether or not the industry needs a distinct definition of hazardous leak and leak or if those [terms] are synonymous or not synonymous." Additionally, public commenters during the proceeding requested that PHMSA consider changes to the leak grading criteria as "adequate in place of a true definition of hazardous leak."

Following public comment, Committee members also provided their comments on the subject. Echoing public commenters, members of the Committee discussed the committee's prior deliberations and recommendations on leak grading criteria and repair requirements and noted that the leak grading criteria "really establishes the difference between hazardous [leaks] and not." Concurring, another Committee member noted, the leak grading criteria "established very clear thresholds that drive action." A Committee member also urged PHMSA to consider the comments received from various State attorneys general on the "the need for clarity on hazardous versus general leak definitions."

4. GPAC Recommendation

The GPAC did not hold a formal vote on this topic. See section III.R.3 (immediately above) for further details on Committee deliberations on this topic.

5. PHMSA Response

Based on the Committee discussion and public comments, in this final rule, PHMSA is removing the proposed definition of the term "leak and hazardous leak." While numerous commenters argued combining the definition required operators prioritize and promptly repair all leaks, PHMSA intended the definition to contain both "leaks" generally and a subset thereof of "hazardous leaks." PHMSA proposed to include hazardous leaks as a subset of leaks in the definition since the term is used in various requirements within part 192. While any leak poses some degree of hazard to the environment, PHMSA did not propose to require operators prioritize and promptly repair all leaks in the NPRM; proposed § 192.760 clearly established a prioritization scheme that differentiated leaks based on the probability or degree of hazard to public safety and the environment. However, PHMSA appreciates the concerns it received that this intent was unclear with the combined definition. Therefore, PHMSA has removed the definition of "leak and hazardous leak" from this final rule.

PHMSA considered adopting separate definitions for the terms "leak" and "hazardous leak" within this rulemaking, however, PHMSA has chosen to remove both definitions. PHMSA considered incorporating the definition for "hazardous leak," used in the DIMP requirements in § 192.1001, into § 192.3. However, PHMSA determined that the grading criteria it is finalizing in this rulemaking at § 192.760 obviates the need to define the term "hazardous leak" in the context of leak detection and repair since the repair requirements are defined by the criteria in that section rather than through the hazardous leak definition itself. While the term "hazardous leak" is referenced elsewhere in the part 192 regulations, primarily in requirements associated with uprating and pressure testing in subpart J (e.g., "potentially hazardous leak"), the NPRM and this final rule did not, and does not, intend to address substantive changes to that subpart and those other sections. Therefore, the interpretation of the term "hazardous leak," as it applies within those contexts and sections, remains unchanged from the status quo. However, retaining the term "hazardous leaks" for those purposes does not imply that leaks other than hazardous leaks, as conceptualized in these legacy requirements, pose no potential hazard to public safety and the environment for the purpose of identifying leaks that require repair in this final rule.

Consistent with the removal of the "leak or hazardous leak" definition, references to the term hazardous leak have been removed from amendments in this final rule for the grading criteria in § 192.760 and procedure manual requirements in §§ 192.12, 192.605, 193.2503, and 195.2605; these references have also been removed from the proposed instructions for Other Gas Transmission and Gathering Pipeline Systems Form (OMB Control No. 2137-0522) and the proposed instructions and current form of the Gas Distribution Annual Report Form and the Natural (OMB Control No. 2137-0629). PHMSA is also withdrawing associated corresponding clarifications to references to hazards in this final rule at §§ 191.23(a)(9), 192.167(a)(2), 192.169(b), 192.179(c), 192.199(e), 192.361(f)(3), 192.363(c), 192.629(a) and (b), 192.727(b) and (c), and 192.751. Similarly, PHMSA has withdrawn proposed revisions at §§ 192.503(a)(2), 192.507(a), 192.509(a), 192.513(b), 192.553(a)(2), 192.557(b)(2), and 192.751(a). Operators should continue to interpret those regulations as they existed prior to the NPRM. Withdrawing these proposed amendments resolves concerns raised by commenters describing how these changes, generally intended to be editorial clarifications, could result in unintended compliance burdens or in some case weaken existing standards.

In this final rule, PHMSA retains its proposed revision at§ 192.1007 to delete reference to § 192.703(c) for the purpose of defining "hazardous leak" as a performance measure under DIMP. As noted above, § 192.703(c) no longer refers to the term "hazardous leak," rendering the cross-reference obsolete. For the purposes of this requirement, operators should either continue to interpret "hazardous leaks" using the definition of "hazardous leak" in § 192.1001 or the definition of a grade 1 leak in § 192.760, which similarly identifies leaks that require immediate and continuous response efforts. Similarly, as described in section III.L, the revised annual report forms use and refer to the leak grades described in § 192.760 to classify leaks rather than using the terms "hazardous" and "non-hazardous."

S. Regulatory Impact Analysis

PHMSA has summarized and responded to comments regarding the PRIA in Appendix C of the final RIA, which is available in the docket for this final rule.

T. General Legal Authority and other Legal Comments

1. Comments Contending that PHMSA is Overstepping its Authority by Attempting to Require Gathering Operators to Submit NPMS Data

<u>*Summary of Public Comments*</u>

PHMSA received comments stating that its proposal to require offshore and Types A, B, and C gas gathering pipeline operators to submit geospatial pipeline location data to the National Pipeline Mapping System (NPMS) overstepped PHMSA's statutory authority under the Pipeline Safety Laws.[451] Most of those comments asserted some basis—either in legislative history of PHMSA's statutory authority at 49 U.S.C. 60132 to administer the NPMS program or the PIPES Act of 2020, application of canons of statutory interpretation, or statements by PHMSA in earlier rulemakings—in support of their contention that 49 U.S.C. 60132 does not authorize PHMSA to

[451] 49 U.S.C. 60101 et seq. See GPA Midstream et al. at 12 (PHMSA-2021-0039-26134); Senator Cruz et al. at 4 (PHMSA-2021-0039-26620); Texas Pipeline Association at 3 (PHMSA-2021-0039-25181).

extend NPMS reporting requirements to gas gathering pipelines. Other comments contended that the language of 49 U.S.C. 60132 actually prohibits the collection of geospatial pipeline data from gathering pipeline operators, thereby barring PHMSA from relying on general safety (49 U.S.C. 60102) and information submission (49 U.S.C. 60117) authorities under the Pipeline Safety Laws to extend NPMS reporting requirements to gas gathering pipelines. The comments submitted by gas gathering operators and industry trade groups also contended that PHMSA's reliance on those other statutory authorities is misplaced because the information PHMSA would collect under the NPMS program would not enhance public safety given that some gas gathering pipeline operators are already required to submit location information to state damage prevention program officials.

PHMSA Response

PHMSA disagrees that it lacks authority to extend NPMS reporting requirements to gathering pipelines; that limitation is not supported by PHMSA's statutes or corresponding legislative history. PHMSA has authority under 49 U.S.C. 60102 to issue minimum safety standards for offshore and part 192-regulated onshore gas gathering (Types A, B, and C) lines for the purposes of pipeline safety and protecting the environment. The statutory language in 49 U.S.C. 60102 contains explicit substantive and procedural guardrails within which PHMSA would implement that provision.[452] PHMSA also has authority under 49 U.S.C. 60117(a) to

[452] See 49 U.S.C. 60102(b)(1) – (2) & (5) (imposing substantive requirements for consideration of certain mandatory factors, and a finding that the benefits of any safety standard justify its costs); 49 U.S.C. 60102(b)(3) – (4) (imposing procedural requirements pertaining to development of a risk assessment and consultation with the GPAC).

require operators of gas pipeline facilities—including gas gathering pipelines—to submit information assisting PHMSA in carrying out its statutory obligations. PHMSA also has explicit authority under 49 U.S.C. 60117(c) to require gathering lines to provide information pertinent to the development of its regulatory oversight over those pipeline facilities. As explained in the NPRM, PHMSA identified public safety and environmental risks associated with the historical exception of gas gathering lines from NPMS reporting requirements in a manner that inhibits knowledge among key stakeholders (including the operators themselves, state and federal regulators, and the public) of the precise location and operating characteristics of those pipelines. The consequences of those barriers to critical pipeline safety information in turn entail risks including inhibition of timely leak detection and repair (which could result in leaks going undetected or unlocated for longer periods of time), heightened vulnerability to pipeline excavation damage, and hampered emergency response efforts in the event of an incident. Although the GPAC did not yield a consensus recommendation in favor of PHMSA's proposal to extend NPMS to gas gathering lines, PHMSA identified through a review of comments received on the issue and the GPAC discussions that much of the resistance to the proposal was based on prioritization of certain considerations (cost, technical feasibility, and practicability) distinguishable from the safety value of such an extension.[453]

Nor is there any meaningful basis within 49 U.S.C. 60132 (and its legislative history) or the Pipeline Safety Laws prohibiting extension of NPMS reporting requirements to part 192-

[453] See, e.g., "GPAC Transcript for Mar. 25, 2024" at 151 ("[T]he bureaucracy of NPMS is heavy. . . . So when we just say . . . do it. . . . that is a big lift, not just a little lift.").

regulated gathering pipelines pursuant to PHMSA's safety and information submission authorities under other provisions of the Pipeline Safety Laws (specifically, 49 U.S.C. 60102 and 60117). The statutory requirement in 49 U.S.C. 60132 for certain operators of gas pipeline facilities other than gas gathering and gas distribution facilities to submit geospatial data to NPMS is self-executing. It is simply a rulemaking mandate to PHMSA, not a limitation on PHMSA's statutory authority to regulate pipeline facilities under other provisions of the Pipeline Safety Laws. Indeed, PHMSA's review of the comments and material cited in those comments (as well as its own review of pertinent legislative history) did not yield a single Congressional statement of the reading of that self-executing statutory language advanced by industry commenters. The cases cited by industry commenters in support of their preferred reading are generally inapposite. None of them involve self-executing statutory requirements; rather, they involve fact patterns where an agency was attempting to pursue policy goals or novel procedural machinery inconsistent with (often adjacent) statutory language.[454] And the D.C. Circuit recently considered and rejected attempts by the gas gathering trade association to derive implicit constraints on PHMSA's exercise of its historical statutory authorities under the Pipeline Safety Laws to extend safety requirements to additional types of pipeline facilities not mentioned in specific Congressional rulemaking mandates.[455] Rather, when Congress has intended to limit

[454] See, e.g., GPA Midstream et al., Supplemental Gas Gathering Industry Comments at 13 & n.42 (PHMSA-2024-0005-0382) ("GPA et al. Supplemental Comments"); Texas Pipeline Association at 3.

[455] See GPA Midstream Ass'n. v. DOT, 67 F.4th 1188, 1195 – 96 (D.C. Cir. 2023). PHMSA acknowledges that on at least one occasion, certain of its personnel have stated that PHMSA believed that it lacked statutory authority to require operators of gas gathering pipelines to submit NPMS data. However, as explained in this section, PHMSA on further evaluation of the legislative history and structure of the Pipeline Safety Laws believes those earlier

PHMSA's exercise of statutory authority (including pre-existing statutory authority), it has expressly done so.[456] Congress declined (both in the 2002 legislation codifying 49 U.S.C. 60132 and in multiple cycles of subsequent reauthorization legislation) to so limit PHMSA's exercise of its historical authorities under 49 U.S.C. 60102 and 60117.

PHMSA disagrees with comments that NPMS data to gas gathering pipelines would be of limited public safety and environmental value. As explained at length in comments and statements during the GPAC meeting, a variety of stakeholders use NPMS data in evaluating the adequacy of PHMSA and state regulatory regimes to address the public safety and environmental risks of gas gathering pipelines; such evaluations can in turn inform PHMSA rulemakings (including this one) directed toward addressing the public safety and environmental risks from gas gathering pipelines. Moreover, as explained at length in the NPRM,[457] GIS data (regarding location, names and contact information of pipeline operators, and other attributes of pipelines such as commodities transported and diameter) within NPMS reinforce existing damage control prevention programs under 192.614,[458] as well as ALDP program requirements. Indeed, the GPAC discussion underscores the potential safety value of extension of NPMS requirements to

statements were incomplete: although PHMSA may lack authority under 49 U.S.C. 60132 to extend NPMS requirements to gas gathering pipelines, it has such authority under other statutory provisions.

[456] See, e.g., 49 U.S.C. 60102(k)(1) (limiting PHMSA's exercise of authority to issue regulations applicable to gathering lines pursuant to a specific statutory mandate); 49 U.S.C. 60109(e)(7)(D)(i)(II)(aa) (limiting PHMSA's consideration of distribution integrity program review results in its exercise of its longstanding authority over State certifications and agreements).

[457] 88 FR 31890 at 31947.

[458] Congress has recognized the value of NPMS for improving emergency response capacity by local first responders. See U.S.C. 60132(c) (contemplating that NPMS submissions for pipeline facilities would "improve local response capabilities for pipeline emergencies by adapting information available through [NPMS] to software used by emergency response personnel responding to pipeline emergencies.").

gas gathering lines; industry representatives mentioned several times that many gas gathering operators' reliance on incomplete or unwieldly paper records means they lack an accessible means of determining the precise location and characteristics of their pipelines.[459] The same reasoning also demonstrates the value of NPMS requirements to regulatory oversight by PHMSA and state regulatory authorities: compliance with PHMSA requirements (whether existing requirements or the leak detection, grading, and repair requirements in the final rule) may be more difficult to ascertain when the precise location of a gas gathering line (among other characteristics maintained in NPMS) is unknown.

Notwithstanding the safety and environmental benefits of extending NPMS to gas gathering lines, and the authorities specified in 49 U.S.C. 60102 and 60117, PHMSA declines to extend the NPMS requirements it had proposed at this time. Many of the gas gathering pipelines—particularly Type C gathering lines—for whom compilation of GIS data within NPMS would yield the most public safety and environmental risks, already face compliance challenges associated with an array of newly-applicable regulatory requirements introduced in a November 2021 final rule. Similar logic also militates against extending NPMS requirements to Type R "reporting-regulated" gas gathering pipelines that pose lower risks to public safety and the environment than part 192-regulated gas gathering pipelines. The enhanced reporting and safety requirements adopted elsewhere in this rulemaking could compound those compliance challenges for some operators. The most efficient, near-term approach to reducing public safety and environmental risks from gas gathering pipelines is to allow operators of those facilities to

[459] See, e.g., "GPAC Transcript for Mar. 25, 2024" at 165 – 66, 183 – 84.

focus their resources on ensuring timely and complete compliance with existing requirements and coming into compliance with other enhanced (non-NPMS) reporting and safety requirements in this rulemaking. Even as it is not in this rulemaking imposing an explicit requirement for gas gathering pipelines to submit GIS data to NPMS, reasonably prudent operators would—either as mandated by applicable state requirements or in response to commercial prerogatives—in ordinary course be investing in efforts to compile, generate, and transfer into an accessible format any legacy records for their systems to protect public safety and the environment from the pressurized (natural flammable, corrosive, or toxic) gases transported in their pipelines. PHMSA applauds those operators who have proactively invested in those efforts.

2. *Comments alleging that the NPRM proposals, if finalized, would exceed PHMSA's statutory authority as a safety regulator*

<u>*Summary of Public Comments*</u>

PHMSA received several comments alleging that adopting various NPRM proposals would exceed PHMSA's statutory grant of regulatory authority. Chief among these arguments is that PHMSA does not have the authority to regulate pipeline leaks to mitigate climate change harms.[460] Commenters cite to various statutory provisions, including the statement in 49 U.S.C. 108(b) that PHMSA's "highest priority" is safety, and claim that leak detection and repair requirements addressing climate change harms would divert limited operator resources from efforts to protect public safety.[461] Senator Cruz et al. alleges that the climate change harms that

[460] Senator Cruz et al. at 3 – 5; LA Attorney General et al. at 1 – 2.
[461] Senator Cruz et al. at 5; LA Attorney General et al. at 1, 2, 7.

could be mitigated under the proposed rule "clearly exceed[s] . . . the authorities Congress granted to PHMSA when it passed the PIPES Act of 2020."[462]

PHMSA Response

PHMSA has considered the various arguments suggesting a zero-sum relationship between protection of public safety and the environment in the Pipeline Safety Laws and finds them unconvincing. Congress has long contemplated that PHMSA's regulation of pipeline facilities—and gas pipeline facilities in particular—should be directed toward protecting both those mutually-reinforcing purposes.

The Pipeline Safety Laws have obliged PHMSA (and its predecessor the RSPA) to consider both public safety and environmental protection when determining that standards for part 192 and 193 governing gas pipeline facilities are "practicable" since 1992.[463] Subsequent legislation also incorporated throughout the Pipeline Safety Laws language explicitly identifying protection against environmental harms alongside protection against public safety harms as a basis for PHMSA regulatory oversight.[464] A number of PHMSA's part 192 regulations

[462] Senator Cruz et al. at 3.

[463] 49 U.S.C. 60102(b)(1)(B) (codifying Pub. L. 102-58).

[464] See, e.g., 49 U.S.C. 60101(a)(23) (introduced in 1996 (via Pub. L. 104-304) to ensure operator risk management plans account for environmental protection alongside public safety); 49 U.S.C. 60102(h)(1)(A)(introduced in 1992 (via Pub. L. 102-508) to ensure operators report hazards to either public safety or the environment); 49 U.S.C. 60108(a)(2)(D)(ii) – (iii)(introduced in 1992 (via Pub. L. 102-508) to ensure operations and maintenance procedures account for protection of the environment alongside public safety); 49 U.S.C. 60112(a)(1) & (2) (introduced in 1992 (via Pub. L. 102-508) authorizing PHMSA to issue corrective action orders to address hazards to either public safety or the environment)); 49 U.S.C. 60117(m) (introduced in 1996 (via Pub. L. 109-468) authorizing PHMSA to issue safety orders addressing pipeline integrity risks to either public safety or the environment); 49 U.S.C. 60117(p)(8) (introduced in 2016 (via Pub. L. 114-183) authorizing PHMSA to issue emergency orders addressing imminent hazards to either public safety or the environment); 49 U.S.C.

consequently contain explicit reference to environmental harms alongside public safety harms.[465] The legislative history of each of those post-1992 statutes include statements emphasizing the centrality of environmental protection to PHMSA's regulatory oversight of gas pipeline facilities.[466] Indeed, Congress's enshrinement of environmental protection alongside public safety as a focus of PHMSA's regulatory activity over gas pipeline facilities reflected a growing "concern about the effect on the environment from oil and gas releases."[467] Although pertinent legislative history acknowledges the practical effect of this elaboration on PHMSA's mission would be to "expand DOT's zone of concern beyond highly populated areas . . . ", those same materials emphasize the complementary nature of environmental and public safety protection

60122(b)(1)(A) (introduced in 1992 (via Pub. L. 107-355) requiring PHMSA to consider potential environmental hazards when imposing civil penalties); 49 U.S.C. 6101 (introduced in 1998 (via Pub. L. 105-178) identifying environmental protection alongside public safety as a primary purpose of one-call systems).

[465] See, e.g., part 192 requirements located at §§ 192.473(c)(2)-(3) (requiring operators to analyze interference survey results and develop remedial action plans where external corrosion control protections could "adversely affect the environment or public"), 192.615(a)(6) (directing operators to include in their emergency plans any actions necessary to "minimize hazards of released gas to life, property, or the environment"), 192.714(b) (requiring that operators repair pipeline systems in a manner "to prevent damage to persons, property, and the environment"), subpart N (defining "qualified" individuals as personnel that can recognize and react to conditions that could "result in a hazard(s) to persons, property, and the environment"), 192.911(o) (requiring transmission pipeline operators to conduct integrity assessments "in a manner that minimizes environmental and safety risks").

[466] See, e.g., H. Rept. 102-247 Part 1 at 18 (Oct. 8, 1991) ("Historically, under [the Hazardous Liquid Pipeline Safety Act] and [the Natural Gas Pipeline Safety Act], DOT has issued safety regulations to prevent damage to property or threats to human life. This section [of legislation that would be codified by Pub. L. 102-508] requires DOT to include protection of the environment as an equal objective when administering the two pipeline safety acts.") and 31 – 32 (noting that Congress in Pub. L. 102-508 adopted language emphasizing the centrality of environmental protection within PHMSA's oversight of gas pipelines over the objections of then-DOT General Counsel who downplayed the environmental risks of those pipelines).

[467] H. Rept. 102-247 Pt. 1 at 14. PHMSA made the same point in the NPRM. 88 FR 31890 at 31953.

given that the specific measures gas pipeline facility operators would employ for each are largely identical.[468]

Consistent with that understanding of its enabling statute PHMSA has on multiple occasions since 1992 explicitly grounded exercise of its 49 U.S.C. 60102 safety authority on (in part) environmental benefits when imposing regulations governing different categories of gas pipeline facilities.[469] Nor does the 2004 statutory language cited by petitioners (and its accompanying legislative history) announce a Congressional change in direction suggesting environmental protection and public safety are competing elements in PHMSA's oversight of gas pipeline facilities. Congress declined in the 2004 Act and subsequent legislation to amend the language introduced in 1992 elevating environmental protection alongside public safety within PHMSA's enabling statute. Some context for the issuance of the 2004 statute omitted from Industry Trades and the LA Attorney General et al. comments is noteworthy. The 2004 statute introducing 49 U.S.C. 108(b) not only re-cast the former Research and Special Projects Administration ("RSPA") as the newly-created PHMSA, but it also established a second entity—the Research and Innovative Technology Administration—that would house the research

[468] See H. Rept. 102-247 Pt. 1 at 14 (noting that "accident and prevention mitigation techniques are the same whether one is protecting the environment or people.").

[469] See, e.g., PHMSA, "Final Rule: Gas Regulatory Reform" 86 FR 2210, 2231 (Jan. 11, 2021) (noting potential environmental benefits from relaxing certain vessel pressure testing requirements at § 192.153); PHMSA, "Final Rule: Safety of Underground Natural Gas Storage Facilities" 85 FR 8104, 8104 & 8123 (Feb. 12, 2020) (emphasizing the environmental benefits of the rulemaking—including climate change benefits); PHMSA, Final Rule: Control Room Management/Human Factors" 76 FR 35130, 35135 (June 16, 2011) (identifying environmental benefits of the rulemaking); PHMSA, "Final Rule: Standards for Increasing the Maximum Allowable Operating Pressure for Gas Transmission Pipelines" 73 FR 62148, 62172 (Oct. 17, 2008) (listing environmental benefits among the anticipated benefits of the rulemaking).

functions formerly performed by RSPA and other DOT Operating Administrations. The specific language in 49 U.S.C. 108(b) cited by Industry Trades and the LA Attorney General et al. can therefore be understood to highlight the distinguishable functions between each of PHMSA and RITA rather than restricting PHMSA's authority to regulate to enhance environmental protection.[470] Instead, Congress has in post-2004 legislation expanded provisions in the Pipeline Safety Laws with language enshrining environmental protection alongside public safety as a focus of PHMSA oversight of gas pipeline facilities and reinforced PHMSA's prerogative to regulate for environmental benefits.[471]

Congressional mandates in the PIPES Act of 2020 implemented in this rulemaking are the latest examples of Congressional intention for PHMSA to exercise its regulatory authority to promote environmental protection alongside public safety. Specifically, Congress in section 113 explicitly directed PHMSA to establish requirements for gas pipeline leak detection and repair programs for certain gas pipeline facilities to "meet the need for . . . safety and to protect the environment" while in section 114 Congress imposed a self-executing obligation on all regulated gas pipeline facility operators to update their procedures to demonstrate promotion of public safety and environmental protection.[472] Similarly, the PIPES Act of 2020 also amended the Pipeline Safety Laws to explicitly provide that PHMSA must predicate its findings that a rulemaking was cost-justified based on both safety and environmental benefits.[473] In the context

[470] See generally H. Rept. 108-749, Pt. 1 at 1 – 2 (Oct. 8, 1991).
[471] See 49 U.S.C. 60117(p)(8) (introduced in 2016 via Pub. L. 114-183); 49 U.S.C. 60102(b)(5) (introduced in 2020 via Pub. L. 116-260).
[472] 49 U.S.C. 60102(q)(1)(A) – (B) and (q)(2)(B); 49 U.S.C. 60108(a)(2)(D)(i) & (iii).
[473] 49 U.S.C. 60102(b)(5).

of another rulemaking mandate in the PIPES Act of 2020 not addressed by this final rule, Congress directed PHMSA to issue regulations for adoption of best available technology and practices for preventing or minimizing releases of natural gas during maintenance activity that would be predicated largely on environmental (as opposed to public safety) benefits.[474] The legislative history of the PIPES Act of 2020 and bipartisan Congressional statements contemporaneous with its adoption highlight that greenhouse gas emissions reduction were among the particular environmental benefits Congress intended those statutory provisions (and PHMSA implementation thereof) to capture.[475] In contrast, there is more than two years of the purpose of the PIPES Act of 2020 and the characterizations of Congressional intent cited by industry commenters or submitted by members of Congress in response to the NPRM.

The specific regulatory amendments adopted in this final rule are consistent with that explicit Congressional direction in the PIPES Act of 2020 and earlier legislation to promote the complementary purposes of public safety and environmental protection.[476] As explained in

[474] See PIPES Act of 2020 at section 114(d) (uncodified mandate).

[475] See, e.g., 166 Cong. Rec. H7301 (Dec. 21, 2020) (statement of Rep. Pallone characterizing the PIPES Act of 2020 as "a big win in the fight against climate change . . . ."); Congressional Summary of the PIPES Act of 2020 (describing sections 113 and 114 as both "address[ing] pipeline methane emissions" to protect both public safety and the environment); Press Release, "Committee Leaders Commend Passage of Pipeline Safety Legislation" (Dec. 22, 2020) (bipartisan statement of support for the PIPES Act of 2020 in which multiple member signatories highlighted the climate change purpose of the legislation).

[476] Consideration of the environmental justice impacts of this rulemaking are a dimension of the public safety and environmental protection at the core of PHMSA's statutory mission, as well as a procedural obligation under Federal statute and guidance, consistent with longstanding Executive Branch and DOT policies. See, e.g., E.O. 12898, "Federal Actions to Address Environmental Justice in Minority Populations and Low-income Populations," 59 FR 7629 (Feb. 11, 1994); DOT, Order 5610.2C, "U.S. DOT Actions to Address Environmental Justice in Minority Populations and Low-income Populations" (May 14, 2021) (noting that is the latest iteration of a DOT order on environmental justice initially issued in 1997). Although some commenters criticized PHMSA's explicit acknowledgement of environmental justice benefits in this rulemaking (see Cruz et al. at 4) those

sections II and III of the final rule, its leak detection, grading, and repair requirements promote both public safety and environmental protection. The final rule explains that leaks from any gas pipeline facility entail some degree of public safety risk as they could portend future acute, catastrophic integrity failure (the leak-before-break concept) at the leak location or signal systemic integrity problems throughout a pipeline segment.[477] And for gas gathering pipelines transporting unprocessed natural gas in particular, the public safety risks from any release (arising either from direct exposure of persons to hazardous constituents entrained in the product stream or an increased risk of accelerated integrity failure from corrosive constituents) are potentially more consequential. Each release of gas from gas pipeline facilities also entails some degree of environmental risk: although every release of methane to the atmosphere represents an environmental hazard from its contribution to climate change, releases of other toxic, hazardous, or corrosive gases (or unprocessed natural gas) risk other adverse environmental impacts.
The final rule's robust leak detection, grading and repair requirements will help ensure that gas pipeline leaks on gas transmission, gas distribution, and gas gathering facilities are timely identified and repaired or monitored commensurate with the risks those leaks pose to public safety and the environment. Leak grading characteristics are predicated principally on consequences to public safety, with grade 1 and 2 leaks subject to more demanding scheduled repairs on timelines consistent with the magnitude of the public safety risk—and therefore the

important, unquantified benefits were informative but not dispositive in PHMSA's decisionmaking in this proceeding.

[477] See, e.g., 88 FR 31890 at 31910; "Transcript of Nov. 28, 2023" at 88 (noting that integrity management plans recognize that leaks on such facilities are managed as potential precursors to catastrophic ruptures).

public safety hazard—posed based on their observed characteristics (e.g., leak rate or volume, operating pressure, location, commodity transported). PHMSA's leak grading requirements also acknowledge that grade 1 and 2 leaks exhibiting characteristics meriting repair to address public safety hazards would also generally have characteristics (e.g., flow rate, operating pressure, etc.) consistent with increased environmental risk—and therefore, potentially an environmental hazard—warranting repair insofar as they would contribute to climate change or other environmental harms. PHMSA's leak grading and repair requirements similarly calibrate repair obligations for leaks whose characteristics pose primarily environmental (as opposed to public safety) risks. Grade 3 leaks whose characteristics (in particular, their release rates) entail larger environmental risks and—therefore environmental hazards—are subject to scheduled repair requirements; conversely, other grade 3 leaks whose characteristics pose less serious environmental risks would not merit scheduled repair but must be monitored lest they exhibit characteristics in the future entailing public safety hazards or environmental hazards warranting repair. In addition, the final rule's mitigation of environmental risks associated with grade 1, 2, and larger grade 3 leaks reinforces the avoidance of downstream consequences for human health and safety from severe weather events and other consequences of climate change.[478]

Similar logic applies to other requirements adopted in this final rule. Enhanced reporting (part 191) requirements reinforce operator implementation of leak detection, grading, and repair requirements and provide information critical for informing PHMSA's future regulatory

[478] *See, e.g.,* 88 FR 31890 at 31910; "Transcript of Nov. 28, 2023" at 88 (noting that integrity management plans recognize that leaks on such facilities are managed as potential precursors to catastrophic ruptures).

oversight of leaks on gas pipeline facilities to address public safety and environmental risks. Additionally, codification in regulation of implementation measures operators of all part 192 and part 193-regulated gas pipeline facilities should undertake in complying with the self-executing mandate in Section 114 of the PIPES Act of 2020 provides a sound basis for PHMSA oversight of operator compliance efforts by setting baseline expectations for those efforts with the high-level statutory language directed toward reducing significant sources of GHG emissions such as blowdowns.[479] And introduction of new methane leak survey requirements for part 193 LNG facilities will reduce public safety risks and environmental risks associated with leaks of explosive and climate change-inducing methane from those gas pipeline facilities.

In light of the above considerations, consideration and evaluation of the substantial environmental benefits of this rulemaking alongside its anticipated public safety benefits are entirely consistent with Congressional direction in the PIPES Act of 2020 and the Pipeline Safety Laws as a whole.

3. *Comments alleging that the NPRM proposals, if finalized, would violate the "major questions doctrine"*

Summary of public comments

Several commenters also alleged that PHMSA's NPRM proposals would violate the Supreme Court's major questions doctrine announced in West Virginia vs. EPA.[480] Commenters argue that Congress's mandate for PHMSA to promulgate leak detection and repair standards "to

[479] The section 114 mandate also exercises PHMSA's public safety and environmental protection authority under 49 U.S.C. 60102.

[480] 597 U.S. 697 (2022).

protect the environment"[481] is too vague and that PHMSA is claiming overbroad, "extraordinary" regulatory authority in violation of clear Congressional intent.[482] Senator Cruz et al. alleged that PHMSA cannot regulate pipeline leaks to protect the environment because this is the sole province of the EPA.[483] The LA Attorney General et al. alleged that PHMSA's use of the social cost of methane ("SC-CH4") to estimate the rule's environmental benefits would also violate the major questions doctrine.[484]

PHMSA Response

PHMSA disagrees that this final rule presents a "major question." As explained above in response to Legal Comment #2 above, Congress's authorization and direction to PHMSA to protect the environment as well as public safety are express, clear, and longstanding. Nor is PHMSA claiming "extraordinary" authority resembling recent agency actions that the Supreme Court has found implicated the major questions doctrine.[485] The final rule acts on the same regulated entities (gas pipeline facilities) to address the same phenomena (leaks and other releases from those facilities) that PHMSA and its predecessors have regulated for decades via a comprehensive suite of regulations. PHMSA in issuing this rulemaking relies on its general

[481] 49 U.S.C. 60102(q)(1)(B).

[482] Senator Cruz et al. at 4; LA Attorney General et al. at 3; Industry Trades at 43. One commenter alleged that PHMSA was claiming "unfettered discretion to regulate." LA Attorney General et al. at 3.

[483] Senator Cruz et al. at 5.

[484] LA Attorney General et al. at 5.

[485] West Virginia v. EPA, 577 U.S. at 724-25 (identifying as a "major questions case" a rulemaking where EPA "'claim[ed] to discover in a long-extant statute an unheralded power' representing a 'transformative expansion in [its] regulatory authority'", relying on an "'ancillary provision[]'" "that was designed to function as a gap filler and had rarely been used in the preceding decades") (quoting Utility Air Regulatory Group v. EPA, 573 U.S. 302, 324 (2014) and Whitman v. American Trucking Assns., Inc., 531 U.S. 457, 468 (2001)).

authority under 49 U.S.C. 60102 that it has repeatedly exercised in regulating gas pipeline facilities to protect the environment as well as public safety. PHMSA also relies on explicit statutory mandates within its 2020 reauthorization statute to consider environmental benefits alongside public safety benefits in any exercise of that statutory authority—an obligation reinforced by the mandate at section 113 of the PIPES Act of 2020 for PHMSA to establish leak detection and repair program requirements "to protect the environment."[486] Other elements of the final rule codify self-executing statutory mandates in section 114 of the PIPES Act of 2020 for operators of all pipeline facilities to update their procedures to eliminate hazardous leaks and minimize releases of natural gas from their facilities. Insofar as these statutory authorities permit or direct PHMSA in this rulemaking to address environmental risks resulting from methane leaks and other releases from gas pipeline facilities (as well as public safety risks), that focus is well-aligned with Congressional delegations of authority to PHMSA.

Nor does this rulemaking evince other indicia of a "major question" identified in Supreme Court decisions. PHMSA does not have or claim an "unfettered discretion to regulate" for environmental protection, as Congress has provided extensive guidance on the required elements of the leak detection and repair programs at the core of the final rule, including that they should "reflect the capabilities of commercially available advanced technologies" and "be able to identify, locate, and categorize all leaks that are hazardous to human safety or the environment," and that PHMSA should include "a schedule for repairing or replacing each leaking pipe, except a pipe with a leak so small that it poses no potential hazard, with appropriate

[486] 49 U.S.C. 60102(b)(5); 49 U.S.C. 60102(q)(1).

deadlines."[487] Similarly, other requirements in the final rule codify self-executing mandates in the PIPES Act of 2020 requiring operators of gas pipeline facilities to amend their inspection and maintenance plans to identify methods for "eliminating hazardous leaks and minimizing releases of natural gas" as well as "protect the environment."[488] Meanwhile, other provisions of PHMSA's enabling statutes impose "specific" and "demanding"[489] procedural requirements—particularly those requiring risk assessment and peer review of its proposed rulemakings—constraining PHMSA decisionmaking in exercising its statutory authorities. And commenters marshalled no legislative history or other evidence indicating that Congress had intended to preclude regulation of gas pipeline facilities with environmental benefits in mind, much less evidence of Congressional intent to reserve such activity for itself or another agency.[490] The major questions doctrine does not require each federal agency to have discrete zones of regulatory authority. While PHMSA and EPA have somewhat overlapping discrete respective authority that overlaps to a certain extent to regulate certain gas pipeline releases under certain circumstances, the agencies are guided by different purposes, rulemaking procedures, and

[487] 49 U.S.C. 60102(q)(2)(A)&(B), (q)(3)(A)(iii).

[488] 49 U.S.C. 60108(b)(2)(D).

[489] GPA Midstream v. DOT, 67 F.4th at 1197. The statutory language in 49 U.S.C. 60102 contains explicit substantive and procedural guardrails within which PHMSA imposes requirements to achieve safety and environmental benefits. See 49 U.S.C. 60102(b)(1) – (2) & (5) (imposing substantive requirements for consideration of certain factors, and a finding that the benefits of any safety standard justify its costs); 49 U.S.C. 60102(b)(3) – (4) (imposing procedural requirements pertaining to development of a risk assessment and consultation with the GPAC).

[490] *Cf.* West Virginia v. EPA, 597 U.S. at 724 ("And the Agency's discovery allowed it to adopt a regulatory program that Congress had conspicuously and repeatedly declined to enact itself."); see also FDA v. Brown & Williamson Tobacco Corp., 529 U.S. 120, 159–160 (finding "reason to hesitate" before concluding that Congress intended to implicitly delegate to FDA the authority to regulate tobacco products, in light of the extensive history of Congressional consideration and rejection of proposals to grant such authority to FDA).

statutory factors for consideration.[491] And as explained in the final rule, PHMSA has adopted a number of regulatory amendments at the request of stakeholders to better complement EPA's exercise of its own statutory authorities. Lastly, PHMSA is not grounding its rulemaking on sweeping re-interpretations of key statutory provisions[492] or adopting a "'radical or fundamental change' to its statutory scheme"[493] (as illustrated by the discussion in PHMSA's response to Legal Comment #2 above); rather, this final rule amends PHMSA's decades-old leak detection and repair requirements for gas pipeline facilities consistent with self-executing obligations and new programmatic elements explicitly mandated by Congress in the PIPES Act of 2020.

Nor does the major questions doctrine prohibit PHMSA's use of recent iterations of the Social Cost of Methane in estimating a rule's environmental benefits. As explained at section 5.1.2 of the RIA, PHMSA's calculation of benefits associated with the final rule is informed by values for the Social Cost of Methane released in late 2023 by the EPA, with an additional analysis performed using interim values for the Social Cost of Methane published by the Interagency Working Group in February 2021. Commenters advancing this argument reference a single

[491] *Compare* 49 U.S.C. 60102(q) (directing PHMSA to promulgate leak detection and repair regulations "to meet the need for gas pipeline safety" and "to protect the environment," including "minimum performance standards that reflect the capabilities of commercially available advanced technologies," and that "are appropriate for" different types of pipelines, different pipeline locations, different pipe materials, and different commodities, among other factors) *with* Clean Air Act § 111 (directing EPA to prescribe standards of performance for limiting emissions of air pollutants reasonably anticipated to "endanger public health or welfare," based on the "best system of emissions reduction" and consideration of other factors, among other goals).

[492] *Cf.* West Virginia v. EPA, 597 U.S. at 728 (observing EPA's shifting historical interpretation of its authority under Section 111(d) of the Clean Air Act and finding that the "newly 'discover[ed]' authority" under EPA's latest interpretation "was not only unprecedented; it also effected a 'fundamental revision of the statute, changing it from [one sort of] scheme of ... regulation' into an entirely different kind").

[493] West Virginia v. EPA, 597 U.S. at 723 (quoting MCI Telecommunications Corp. v. American Telephone & Telegraph Co., 512 U. S. 218, 229 (1994)).

district court decision that was subsequently vacated by the Fifth Circuit Court of Appeals.[494] PHMSA declines to change its current rulemaking practices based on a single district court opinion, which has since been vacated.[495] In fact, other courts have in the past found that federal agencies may (or sometimes must) use values for the social cost of other greenhouse gases to inform their decision making when—as in PHMSA's case—such use is appropriate to fulfill agencies' statutory mandates or comply with statutes such as the National Environmental Policy Act.[496] More broadly, courts have also held that agencies generally may consider the global impact of greenhouse gas emissions in their decisionmaking.[497] Commenters have not identified a single provision in PHMSA's enabling statutes restricting consideration of potential public safety and environmental benefits beyond U.S. borders as an input to PHMSA decisionmaking; rather, the statutory text at 49 U.S.C. 60101(b)(5) explicitly directs PHMSA to consider environmental benefits without qualification. Indeed, the Pipeline Safety Laws acknowledge an international nexus for some of the gas pipeline facilities subject to PHMSA regulation.[498] Finally, as described in more detail in the RIA accompanying this final rule, global SC-GHG values are appropriate for this analysis due to the global nature of the climate change, as climate

[494] *See* Louisiana v. Biden, 64 F.4th 674 (5th Cir. 2023)

[495] As the Supreme Court has said, "The point of vacatur is to prevent an unreviewable decision 'from spawning any legal consequences,' so that no party is harmed by what we have called a 'preliminary' adjudication." Camreta v. Greene, 563 U.S. 692, 713 (2011) (quoting U.S. v. Munsingwear, Inc., 340 U.S. 36, 40 – 41 (1950)).

[496] *See, e.g.*, Center for Biological Diversity v. NHTSA, 538 F.3d 1172 (9th Cir. 2008).

[497] *See* Center for Biological Diversity v. U.S. Dept. of Interior, 563 F.3d 466, 585-86 (D.C. Cir. 2009); Zero Zone, Inc. v. U.S. Dep't of Energy, 832 F.3d 654 (7th Cir. 2016) (finding that "national energy conservation has global effects, and therefore, those global effects are an appropriate consideration when looking at a national policy.").

[498] *See* 49 U.S.C. 60101(a)(21) (definition of "transportation of gas" in terms of transportation in interstate or foreign commerce). PHMSA also regulates under part 193 LNG facilities whose primary purpose is export of natural gas.

impacts directly and indirectly affect the welfare of U.S. citizens and residents through complex pathways that spill across national borders and those impacts are more fully captured within global measures of the social cost of greenhouse gases.

For the reasons explained above, PHMSA's use of the Social Cost of Methane metric to inform its decisionmaking in this rulemaking is entirely appropriate. The RIA explains at length at section 5.1 PHMSA's reasoning in concluding that EPA's latest Social Cost of Methane values –complemented by an additional analysis employing the Interagency Working Group's Social Cost of Methane values issued in February 2021—constitute a sound approach to monetizing greenhouse gas impacts within its primary economic analysis.[499] In addition, none of the procedural notice deficiencies alleged in the Fifth Circuit litigation over use of the February 2021 Social Cost of Carbon values referenced by commenters are present here. The PRIA supporting PHMSA's NPRM had within its economic analysis used interim Social Cost of Methane values published by the 2021 Interagency Working Group, and referenced updated values for the social cost of methane developed in connection with a 2022 EPA proposed rule.[500] At the March 2023 GPAC meeting, PHMSA economists elaborated on that earlier analysis, demonstrating in a presentation that PHMSA's determination in the PRIA that each element of the proposed rule was cost-justified would not be materially altered were PHMSA to employ EPA's updated values for the Social Cost of Methane.[501] PHMSA has also provided an additional analysis in the RIA using Social Cost of Methane values issued by the 2021 Interagency Working Group (IWG) for

[499] RIA at 5.1.2, Table 52, Table A-1, Table A-2. *See also* RIA at 2.1.2.
[500] PRIA at sections 5.1.2 & 5.6.
[501] "GPAC Transcript for Mar, 25, 2024," at 15-17.

comparison purposes.[502] The monetized benefits of this regulation exceed the monetized costs regardless of whether the EPA or IWG values are used.

4. Comments alleging that the NPRM's proposed leak detection, repair, and grading requirements exceed PHMSA's statutory authority under section 113 of the PIPES Act of 2020"

<u>*Summary of Public Comments*</u>

PHMSA received comments alleging that it misinterpreted the mandate in section 113 of the PIPES Act of 2020 implemented by this rulemaking. Specifically, some commenters contended that PHMSA erroneously interpretated section 113 of the PIPES Act of 2020 in concluding that Congress directed PHMSA to require detection, grading, and repair of all leaks from gas pipeline facilities based on the premise that every leak is per se "hazardous." Rather, those commenters assert Congress chose to frame the section 113 mandate not in terms of all leaks, but instead included qualifying language specifying that the mandate would apply only to some leaks: specifically those that are "hazardous to human safety or the environment" or those leaks that "have the potential to become explosive or otherwise hazardous to human safety."[503] Although commenters advancing this argument proffer different readings as to precisely which

[502] RIA at Tables A-1 and A-2.

[503] *See, e.g.*, Senator Cruz et al. at 3; LA Attorney General et al. at 2; Industry Trades et al. at 9, 42-43; INGAA at 13 (Doc. No. PHMSA-2021-0039-26287).

leaks that statutory language would encompass,[504] some agree that it would exclude any "leak so small that it poses no potential hazard"—which in practical terms commenters aligned with the pipeline industry generally understood to exclude leaks whose principal environmental hazard consists of their contribution to climate change. Those same commenters contend that their preferred reading is reinforced by language elsewhere within the section 113 mandate referring to "leak[s] so small that [they] pose[] no potential hazard . . . ", as well as language within section 114 of the PIPES Act of 2020 in which Congress similarly limits the scope of that mandate to certain leaks (specifically, "hazardous leaks") rather than all leaks.[505] However, PHMSA also received a number of comments taking the opposite position: that the section 113 mandate text, legislative history, and other contextual clues support PHMSA's understanding in the NPRM that all leaks from gas pipeline facilities are per se hazardous and therefore merit scheduled repair.[506]

PHMSA Response

PHMSA has reviewed the comments asserting that PHMSA exceeded its section 113 mandate and disagrees. First, in 49 U.S.C. 60102(q)(2)(B), Congress mandated that LDAR programs "shall be able to identify, locate, and categorize all leaks that—(i) are hazardous to

[504] *See, e.g.*, Senator Cruz et al. at 3; Industry Trades at 43. By way of example, AGA et al. claimed that interpretation of this statutory language should be limited by the preexisting regulatory definition of "hazardous leak" in 49 CFR 192.1001 and PHMSA's historical interpretations of the term "hazardous" in 49 CFR 192.703, and that this interpretation should be further constrained by EPA's oil and gas new source performance standards (NSPS) regulations promulgated under the Clean Air Act. Industry Trades at 42 – 44.

[505] Senator Cruz et al. at 3; LA Attorney General et al. at 2 – 3; Industry Trades at 9, 42 – 43; INGAA at 13. The referenced provisions in Section 113 include 49 U.S.C. 60102(q)(3)(A)(iii) and 60102(q)(2)(B).

[506] *See, e.g.*, EDF et al. at 33 – 40, (PHMSA-2021-0039-26522); Attorney General of Maryland et al. at 3, (PHMSA-2021-0039-26137).

human safety or the environment; or (ii) have the potential to become explosive or otherwise hazardous to human safety." Congress therefore exempted only those leaks that neither are hazardous to human safety or the environment nor have the potential to become hazardous to human safety. Second, in 49 U.S.C. 60102(q)(3)(A)(iii), Congress required that the regulations "include a schedule for repairing or replacing each leaking pipe, except a pipe with a leak so small that it poses no potential hazard, with appropriate deadlines." Therefore, the mandate also exempts any small leaks that do not pose a potential hazard from the repair timelines required in this rulemaking. In the final rule, PHMSA has acted in accordance with this Congressional mandate.

Consistent with the Congressional direction to require identification, location, and categorization of certain leaks in 49 U.S.C. 60102(q)(2)(B), and as specifically directed by 49 U.S.C. 60102(q)(2)(A), PHMSA sets minimum performance standards for leak detection equipment in 49 CFR 192.763(b). For leakage surveys of gas transmission and gas gathering lines, screening surveys must be conducted with equipment that can detect leaks of 10 kg/hr with a 90 percent probability, and handheld leak detection equipment must have a minimum sensitivity of 5 ppm or 5 ppm-m, with alternative standards for surveys of pipelines inside of buildings and non-buried appurtenances. Gas distribution lines have the same performance criteria for handheld equipment, but screening surveys must be capable of detecting leaks of 0.2 kg/hr with a 90 percent probability. The performance criteria permit some small leaks to avoid detection. In setting this performance criteria, PHMSA considered the extent to which leaks are hazardous to human safety and the environment as well as the costs and practical considerations of the LDAR programs that operators will implement under this rule with respect to requirements to identify, locate, and categorize leaks. Because of the net quantified benefits of imposing leak detection requirements using the performance standards described above, and in consideration of further non-quantified benefits including safety benefits, PHMSA finds that the performance standards will identify leaks that satisfy the criteria in 49 U.S.C. 60102(q)(2)(B). Specifically, the avoided harms in the form of safety and environmental benefits demonstrate that the leaks that are found by the equipment required by this rulemaking are "hazardous to human safety or the environment."

Similarly, consistent with the Congressional direction to set repair schedules of certain leaks in 49 U.S.C. 60102(q)(3)(A)(iii), PHMSA has excepted from repair requirements small leaks that do not pose a potential hazard. In 49 CFR 192.760(d)(2)(ii), PHMSA excepts certain grade 3 leaks from the repair requirement that generally applies within 36 months of discovery of the leak. Specifically, grade 3 leaks with a measured or calculated emissions rate of less than 5 SCFH or a below-grade or subsurface grade 3 leak on a pipeline operating at less than 20% of SMYS with a measured leak extent area of less than 1800 square feet, or a grade 3 leak determined by an alternative method to be equivalent to a measured or calculated emissions rate of less than 5 SCFH. Again, in setting these criteria, PHMSA considered the extent to which leaks are potentially hazardous to human safety and the environment, as well as the costs and practical considerations of the LDAR programs with respect to requirements to repair leaks that are identified by operators. Because of the net quantified benefits of imposing repair requirements that exempt small leaks as described above, and in consideration of further non-quantified benefits including safety benefits, PHMSA finds that leaks that must be repaired under the rule meet the criteria in 49 U.S.C. 60102(q)(3)(A)(iii). Specifically, the avoided harms in the form of safety and environmental benefits demonstrate that the leaks for which this rulemaking requires repair "pose … potential hazard[s]" to safety or the environment.

PHMSA appreciates the commenters that asserted that any leak is potentially hazardous to human safety and that any leak presents an environmental hazard. Prior PHMSA regulations applying to "hazardous leak" have not historically been understood to encompass environmental hazards, [507] but that conflicts with the section 113 mandate that explicitly references environmental hazards (49 U.S.C. 60102(q)(2)(B)(i)) and language in the section 113 mandate identifying environmental protection as a goal of operator leak detection, grading, and repair requirements (49 U.S.C. 60102(q)(1)(B)); as well as contemporaneous Congressional statements highlighting the climate change benefits of the PIPES Act of 2020 referenced in PHMSA's response to Legal Comment #2 above. Further, alleged silence by EPA regarding climate change hazards of methane releases is not true, nor are such allegations relevant for interpreting PHMSA's distinguishable statutory authority.[508] Therefore, PHMSA in this rulemaking

[507] This is discussed at greater length in the final rule preamble at section II.C.

[508] Industry Trades at 42 – 44. See also EDF et al. at 39 – 40 (explaining that EPA's distinguishable authority under the Clean Air Act does not constrain PHMSA's authority under the Pipeline Safety Laws). EPA's regulation of methane from certain oil and gas sources under section 111 of the Clean Air Act implements entirely different statutory language (specifically, standards based on the "best system of emissions reduction" and other factors to address "air pollutants" that are reasonably anticipated to "endanger public health or welfare,"). The Industry Trades argument conflicts with EPA's dire descriptions of the climate change contributions of methane leaks. *See, e.g.*, EPA, "Final Rule: Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" 89 FR 16820, 16823 – 24 (Mar. 8, 2024) ("[E]very natural gas leak or intentional release of natural gas through venting or other processes

incorporates the consideration of environmental benefits in exercising its authority over crucial LDAR requirements such as the performance standards of leak detection equipment and the repair schedules required of the various types of leaks that operators find. But as noted above, Congress delineated the coverage of the LDAR requirements by setting the standards in 49 U.S.C. 60102(q)(2)(B) and 49 U.S.C. 60102(q)(3)(A)(iii). The most natural and best reading of these standards in the section 113 mandate is that Congress intended for PHMSA to apply its expertise in selecting requirements for operator leak detection and repair programs that would address the environmental and safety hazards of methane leaks, and that PHMSA should not apply leak detection requirements that apply to all leaks no matter how small or how tenuous and obscure any potential hazards may be. This interpretation aligns with other aspects of the section 113 mandate. For example, Congress chose language at 49 U.S.C. 60102(q)(1)(A) committing to PHMSA's expert judgment the precise content of regulations governing operator leak detection and repair programs after "determin[ing]" that any such requirements "met the need for gas pipeline safety." The statutory text in 49 U.S.C. 60102(q)(1)(B) provides that PHMSA's leak detection and repair programs regulations must "protect the environment." Similarly, 49 U.S.C. 60102(q)(2)(A) entrusts to PHMSA authority to design minimum performance standards for those leak detection and repair programs that are "appropriate" with respect to specified factors including the type, material, and location of the pipeline, as well as the commodity being transported. The section 113 mandate also did not alter longstanding statutory language

constitutes a release of methane. Reducing human-caused methane emissions, such as controlling natural gas leaks and releases through the measures in this final action, is critical to addressing climate change and its effects.").

elsewhere within 49 U.S.C. 60102 acknowledging PHMSA's authority to determine the "adequa[cy]" and "appropriateness" of requirements imposed by PHMSA regulations by reference to factors such as practicability, technical feasibility, and reasonableness and after having evaluated the costs and benefits of any new requirements.[509]

PHMSA has therefore relied on its expertise and on the extensive rulemaking record to define the content of each component of operator programs consistent with the text and purpose of the statutory mandate. As noted above (which in turn references PHMSA's response to Legal Comment #2), the section 113 mandate addresses the contribution of methane leaks from natural gas pipelines to anthropogenic climate change. The "hazardous to human safety or the environment" language in 49 U.S.C. 60102(q)(2)(B) is consistent with that purpose: operator programs must provide for the detection, location, and grading of all methane leaks detected using advanced leak detection equipment and methods compliant with the final rule's performance standards (or otherwise known to the operator). Similarly, the exception from repair criteria for "a leak so small that it poses no potential hazard" in 49 U.S.C. 60102(q)(3)(A)(iii) is consistent with that purpose: operators must repair leaks according to set schedules that are based on the severity of the leak and the risks to human safety and the environment, and those leaks that are required to be repaired do not fall into the exception provided by Congress because they are hazardous to safety or the environment or have the potential to pose such hazards.

[509] *See, e.g.*, 49 U.S.C. 60102(a)(1)("provide adequate protection . . . ."); 49 U.S.C. 60102(b)(2) (requiring PHMSA consider the "appropriateness" and "reasonableness" of any standard); 49 U.S.C. 60102(b)(5) (entrusting PHMSA with the authority to adopt standards on its "reasoned determination"). PHMSA is also required by statute to submit any proposed new requirement to an advisory committee for review (49 U.S.C. 60115) and subsequently adopt those requirements only after having determined that the benefits justify any costs (49 U.S.C. 60102(b)(5)).

5. Comments alleging that the NPRM's proposed requirements implementing section 114 of the PIPES Act of 2020 exceed PHMSA's authority under that provision

Summary of Public Comments

PHMSA also received comments alleging that it had misconstrued the self-executing mandate at Section 114 of the PIPES Act of 2020. Some commenters assert that section 114 does not impose a self-executing mandate for gas pipeline facilities to update their inspection and maintenance plans to provide for eliminating hazardous leaks and minimizing releases of natural gas at all; rather, the section 114 mandate imposes only mandatory considerations on PHMSA and State enforcement authorities as those regulatory authorities review existing operator inspection and maintenance procedures.[510] In contrast, other commenters agreed with statements in the NPRM that section 114 imposes a self-executing mandate directly on operators of all gas pipeline facilities regulated by PHMSA.[511] Some commenters contend that any self-executing obligations under section 114 would apply only to gas pipeline facilities regulated by PHMSA as of the December 2020 enactment date of the PIPES Act of 2020.[512] Additionally, other comments relate to the timing of operators' obligations under section 114, as commenters claimed that Congress intended for a series of conditions precedent (issuance of a rulemaking implementing Section 113; PHMSA's submission of a report to Congress on best available technologies and practices to prevent or minimize natural gas releases; or the Comptroller General's consideration

[510] Industry Trades at 10; GPA Midstream et al. at 17.
[511] MD Attorney General et al. at 12, 19; EDF et al. at 35 – 36.
[512] GPA Midstream et al. at 4 – 6 & 17.

of the results of PHMSA's inspection of operator compliance with section 114) to PHMSA promulgating regulations implementing section 114.[513]

PHMSA Response

PHMSA has reviewed the criticisms above and disagrees with them. In 1976, in 49 U.S.C. 60108(a)'s predecessor provision, Congress issued a self-executing mandate on operators themselves even as it also authorized and obliged PHMSA and its predecessors to evaluate the "adequacy" of those plans.[514] Although subparagraph (a)(2) has historically prescribed certain high-level objectives for those operator plans,[515] nothing in the structure or legislative history suggests that list is exhaustive. Instead, in determining whether an operator's plan is "adequate," PHMSA necessarily determines compliance with those high-level objectives by evaluating (among other things) compliance with self-executing statutory mandates and requirements in PHMSA regulations (which themselves were generally adopted to promote the same high-level objectives specified in 49 U.S.C. 60108(a)(2)) that do not appear in 49 U.S.C. 60108(a).[516] But within the bounds of the general Congressional mandates and PHMSA requirements, operators may need to employ different compliance strategies tailored to their facilities; the end of 49

[513] Industry Trades at 10.

[514] Section 6 of Pub. L. 94-477 (amending 49 U.S.C. 60108(a)'s predecessor (49 App. 1680(a)) to establish a self-executing mandate for operators themselves to have and provide to PHMSA and state regulators inspection and maintenance plans for their facilities).

[515] Section 210(b) of Pub. L. 96-129 (adding requirements at (a)(2) that operator plan adequacy be evaluated based on whether those plans are "practicable," "designed to meet the need for pipeline safety") and section and "designed to enhance the ability to discover safety-related conditions . . . ."). The reference to safety-related condition reporting was added later.

[516] 49 U.S.C. 60108(a)(2) ("If the Secretary or a State authority responsible for enforcing standards prescribed under this chapter . . . .").

U.S.C. 60108(a)(2) at subparagraphs (A) – (C) consequently has long provided that PHMSA's determination of the "adequacy" of operator plans also turns on factors speaking to the efficacy of those plans.[517] The specific factors listed in 49 U.S.C. 60108(a)(2)(A) – (C) therefore function as self-executing mandates on operators themselves, as their inspection and maintenance plans must exhibit those listed characteristics even in the absence of an explicit textual formulation elsewhere in 49 U.S.C. 60108(a)(1) directing operators amend their inspection and maintenance plans for "appropriateness" or "reasonableness."

PHMSA therefore has consistently stated that the PIPES Act of 2020's additional factors against which PHMSA must evaluate the adequacy of operator inspection and maintenance plans are a Congressional statement of those plans' required content—i.e., a self-executing mandate on operators in designing their plans evaluated by PHMSA.[518] This reading is consistent with characterizations of the self-executing nature of the section 114 mandate within statements by cognizant committee chairs and ranking members contemporaneous with passage of the PIPES Act of 2020. It is also consistent with language within paragraph (a) of the section 114 mandate, which explicitly directs "each pipeline operator" to update its inspection and maintenance plans to address amendments to 49 U.S.C. 60108(a) introduced by the section 114 mandate. In contrast, the alternative reading of section 114 advanced by operators (in which the list of factors

[517] Section 11 of Pub. L. 90-481 (specifying factors such as "appropriateness of the plan for the particular kind of pipeline transportation or facility" and "the reasonableness of the plan.").

[518] PHMSA, ADB-2021-01; PHMSA Press Release, "Committee Leaders Commend Passage of Pipeline Safety Legislation" (Dec. 22, 2020) (characterizing section 114 as "[r]equir[ing] updates to inspection and maintenance plans for covered pipeline operators to identify ways to minimize leaks and require PHMSA to study ways of updating regulations to minimize natural gas releases . . . .").

at the end of 49 U.S.C. 60108(a)(2) are not binding for operators, but binding on PHMSA and state regulatory authorities) risks making historical language in that subsection—which appears nowhere else in the Pipeline Safety Laws or PHMSA regulations as an explicit requirement on operators—surplusage; under that alternative reading, PHMSA and state regulatory authorities would need to evaluate the adequacy of operator plans against factors ("reasonableness"; "appropriateness") identified in those provisions even as those same factors (so commenters' argument goes) would not be required for operators.

In addition, the self-executing section 114 mandate would not only apply to gas pipeline facilities regulated by PHMSA at enactment (in December 2020) of the PIPES Act of 2020, but any other gas pipeline facilities subsequently determined by PHMSA to be "gas pipeline facilities" subject to PHMSA safety and environmental protection regulation. The entirety of 49 U.S.C. 60108(a) is self-executing and applies to all regulated pipeline facilities. The function of the plain legislative text is that every regulated pipeline facility, including those that become subject to PHMSA's regulations in the future, must create and follow an inspection and maintenance plan. This self-executing language is an exercise of Congress' authority to directly and immediately apply requirements to all pipeline facilities that are subject to PHMSA's regulation. Here, the self-executing legislative mandate is written to apply to all regulated pipeline facilities and there is no text constraining the mandate by time or category of pipeline. To read this provision in any other way would subvert clear Congressional authority to directly mandate the activities of pipeline operators. Pursuant to 49 U.S.C. 60101, Congress has delegated to PHMSA authority to determine whether a particular gathering pipeline is a "gas pipeline facility" engaged in "transporting gas" under the Pipeline Safety Laws. The mechanics of this delegation are in paragraphs (b) (authorizing PHMSA to determine whether a particular gathering line is a "regulated gathering line"); once designated as a "regulated gathering line," the pipeline is said to be "transporting gas" pursuant to (a)(21), which is in turn an input to the definition of "gas pipeline facility" at (a)(3). This includes Type C gas gathering pipelines, which became regulated by PHMSA pursuant to a final rule issued by PHMSA in November 2021.[519] Although GPA Midstream et al. contend that Congress could not have intended at the time of enactment of the section 114 mandate in December 2020 for that self-executing mandate to apply to the newly-created class of Type C gathering lines, Congress had constructive notice that the rulemaking it directed PHMSA to issue by March 2021 would broadly expand the scope of application of PHMSA's safety regulations to large-diameter (8.625" or greater) gas gathering lines in Class 1 locations. See PHMSA, "PHMSA Response to Questions for the Record from Sen. Cantwell following Senate Commerce, Science and Transportation Committee Apr. 10, 2019 Hearing" at 2-3 & 17-18 (2019). The text of section 114 mandate (as well as the Congressionally-generated summary thereof) pointedly did not include an explicit exception for Type C gathering lines (even as Congress did employ language omitting Type C gas gathering lines from the scope of the section 113 mandate). Further, GPA Midstream et al.'s preferred reading of the function of a self-executing statutory mandate would result in absurd result whereby any gas gathering pipeline facilities newly subject to PHMSA safety regulations would not be subject to other longstanding self-executing statutory provisions in the Pipeline Safety

[519] 86 FR 63266.

Laws. Further, the section 114 mandate to Type C gas gathering pipelines is consistent with Congressional intent memorialized in the PIPES Act of 2020. Specifically, section 112(a) directed PHMSA to issue within 90 days of enactment (i.e. in March 2021) a final rule for a 2016 rulemaking that had proposed to expand the universe of gas gathering lines subject to PHMSA safety regulation along the lines ultimately adopted in November 2021. That proposal to bring Type C gathering lines within the scope of "gas pipeline facilities," moreover, was discussed over a two-day-long GPAC in June 2019.

PHMSA's interpretation of section 114 as a self-executing mandate on operators is also consistent with the December 2021 deadline for those updates within uncodified paragraph (a)—a year before the December 2022 Congressional deadline in the PIPES Act of 2020 section 113 mandate (codified at 49 U.S.C. 60102(q)(1)) for PHMSA to issue leak detection, grading and repair requirements. Although some industry commenters contend that addition of the language at 49 U.S.C. 60108(a) referencing regulations issued pursuant to section 113 is evidence that Congress intended for those regulations to be conditions precedent to the section 114 mandate, PHMSA submits that reading is not a necessary—or even a plausible—understanding of the statutory text. First, that reading is hard to square with the December 2021 deadline for operators to have updated their inspection and maintenance plans. Second, PHMSA is unable to find in either the statutory text or the legislative history an explicit prohibition on PHMSA pursuing a leak detection, repair, and grading rulemaking in parallel with its review of operator inspection and maintenance plans and the various reports and studies identified in section 114; rather, the section 114 language added at 49 U.S.C. 60108(a) admits contingency as to whether PHMSA has issued its regulations pursuant to the section 113 mandate or not by the time that PHMSA evaluates those plans as required under the section 114 mandate.[520] Third, the language at 49 U.S.C. 60108(a) referenced by industry commenters is a continuing obligation for PHMSA and pipeline operators that could accommodate revisions to operator inspection and maintenance plans to account for regulatory amendments introduced by this or amended by any subsequent final rule.[521] Lastly, any rulemakings that section 114 mandates would follow the various required reports and studies could be conducted in parallel or following this final rule.

6. *Comments alleging that PHMSA's proposals related to certain gas pipeline facilities would, if adopted, exceed its authority under the PIPES Act of 2020*

<u>*Summary of Public Comments*</u>

PHMSA received a number of comments alleging that various proposals within the NPRM exceeded the scope of PHMSA's mandates under sections 113 and 114 of the PIPES Act of 2020. Notable among those criticisms were assertions by gas gathering trade associations that PHMSA lacked authority under the PIPES Act of 2020 to extend leak detection, grading, and repair criteria to offshore and Type C gas gathering pipelines that were not within the explicit scope of PHMSA's section 113 rulemaking mandate. Similarly, trade associations and

[520] 49 U.S.C. 60108(a)(2) ("A plan . . . must meet the requirements of any regulations promulgated under [the section 113 mandate codified at] 49 U.S.C. 60102(q) . . . ."). Congress did not require the rulemaking to be a condition precedent to operators updating their inspection and maintenance plans.

[521] The arguments offered here in rebuttal to commenters' characterization of a rulemaking implementing the section 113 mandate as a condition precedent for the section 114 mandate apply with even greater force to other PIPES Act of 2020 rulemaking mandates (e.g., following a report to Congress on best available technologies, and in response to a subsequent GAO study on PHMSA's review of operator inspection and maintenance plans) those commenters characterize as conditions precedent to the section 114 mandate. Specifically, each of those mandates involve even later deadlines than the two-year Congressional deadline for the section 113 mandate.

stakeholders in the LNG industry contended that the NPRM's proposed extension of leak detection requirements to LNG facilities cannot be predicated on the section 113 mandate, which by its terms excludes those facilities from its scope.[522]

PHMSA Response

PHMSA agrees with commenters that the requirements of section 113 do not explicitly extend to offshore gas gathering lines, Type C gas gathering lines, and LNG facilities. However, as explained in PHMSA's response to Legal Comment #4 above, the Pipeline Safety Laws at 49 U.S.C. 60102(a) grant PHMSA authority to establish standards addressing the safety and environmental risks associated with offshore gas gathering lines, Type C gas gathering pipelines, and LNG facilities—each of which are "gas pipeline facilities" under the Pipeline Safety Laws.[523] That safety and environmental protection authority with respect to LNG facilities is reinforced by an additional grant of authority at 49 U.S.C. 60103(d) to impose operation and maintenance standards for those facilities. Nothing in the text of the PIPES Act of 2020 nor its legislative history prohibits PHMSA from requiring that LNG facilities, offshore lines, and Type

[522] See, e.g., Texas Pipeline Association at 1 – 2; GPA Midstream et al. at 3, 8; Industry Trades at 143; Kinder Morgan, Inc. at 4 – 5, (PHMSA-2021-0039-26306).

[523] The statutory language in 49 U.S.C. 60102 contains explicit substantive and procedural guardrails within which PHMSA would exercise that provision. See 49 U.S.C. 60102(b)(1)-(2) & (5) (imposing substantive requirements for consideration of certain mandatory substantive factors, and a mandatory finding that the benefits of any safety standard justify its costs); 49 U.S.C. 60102(b)(3)-(4) (imposing procedural requirements pertaining to development of a risk assessment and consultation with the GPAC).

C gathering lines have (as applicable) robust leak detection and repair programs as PHMSA determines is necessary to address safety and environmental risks from those facilities.[524]

As explained in sections II.B.3-4 and II.C.3, extension of robust leak detection, grading, and repair criteria to the 5,231 miles of offshore gas gathering and ca. 90,000 miles of Type C gas gathering pipelines is necessary to protect public safety and the environment from leaks on those lines, and the benefits of including these gathering lines exceed the costs that will be imposed. In addition to methane leaks from natural gas offshore and Type C gas gathering representing an important contributor to climate change, the unprocessed gas in those lines poses an acute risk to human safety and the environment as they typically contain volatile organic compounds (VOCs), which are precursors to ozone and fine particulate matter, and hazardous air pollutants (HAPs) such as benzene, formaldehyde, toluene, xylenes, and ethylbenzene. Leaks of unprocessed gas transported by gathering lines also pose a higher risk of corrosion rate in the vicinity of a leak, increasing the risk of a catastrophic pipeline failure that could in turn result in public safety and environmental harms. These public safety and environmental risks from leaks are particularly acute for Type C gas gathering lines, which, although they may be located in rural areas, have characteristics (operating pressures, diameter, etc.) that would result in substantial adverse public safety and environmental consequences in the event of an incident. Application of robust leak detection, grading and repair criteria to offshore and Type C gas

[524] When Congress has intended to limit PHMSA's authority to issue certain standards with respect to gas gathering lines, it has expressly done so by using language such as "[t]he regulations issued under this paragraph shall not apply to gathering lines," "[t]he regulations issued under this paragraph shall not apply to production or flow lines," and "excluding any proprietary or sensitive security information." See 49 U.S.C. 60102(k), 60108(c), 60132(d).

gathering pipelines also reinforces their obligations under the broad language in the self-executing section 114 mandate to ensure those facilities' inspection and maintenance procedures contribute to public safety, eliminate hazardous leaks, and minimize releases of natural gas. PHMSA discusses the exercise of its statutory authorities in connection with Type C gas gathering at greater length in its responses to Legal Comments # 4 and 5.

Similar reasoning supports extension of more limited methane leak detection and repair requirements to LNG facilities. Here, the final rule at III.C.4 explains that equipment leaks and other fugitive emissions are in fact the second largest methane emissions source from LNG storage facilities and the largest methane emissions source from LNG export terminals. Ignition of any of those leaks can pose particularly acute public safety and environmental risks given the extended length of piping and enormous explosive potential of some LNG facilities; each methane leak, moreover, would—even if not ignited—entail an environmental hazard given its contribution to climate change. The final rule consequently adopts a limited number of targeted, common-sense, amendments to part 193, subpart G maintenance requirements to address those risks. The final rule amends § 193.2605 to require that all LNG facility operators update their operating procedures to introduce an explicit, high-level requirement for their maintenance procedures to address leaks—leaving operators with flexibility to design a compliance regime appropriate for their facilities. The final rule also introduces at § 193.2624 high-level, largely operator-driven requirements for leakage surveys on certain LNG facilities. These requirements for LNG facilities reinforce operator obligations under the broad language in the self-executing section 114 mandate to ensure inspection and maintenance procedures contribute to public safety, eliminate hazardous leaks, and minimize releases of natural gas. PHMSA discusses the exercise of its statutory authorities in connection with LNG facilities at greater length in its responses to Legal Comments # 4 and 5.

7. *Miscellaneous comments alleging that PHMSA violated notice and other miscellaneous requirements under the Administrative Procedure Act and Pipeline Safety Laws*

Summary of Public Comments

PHMSA received several comments alleging that its issuance of the NPRM violated various requirements of the Administrative Procedure Act (APA). Specifically, some commenters alleged that PHMSA had failed to provide "critical information" needed to substantiate the safety, environmental, or economic rationales supporting the rulemaking.[525] Others contended that PHMSA's solicitation of stakeholder feedback on certain issues, including potential alternatives to (or adjustment of) specific proposals in the NPRM, for potential inclusion in the final rule violated APA notice requirements by providing too little discussion of the particulars or substance of those topics to ensure meaningful public comment.[526] Some of those commenters elaborated on their criticisms by asserting that the GPAC discussion of those issues or alternatives during the GPAC could not cure the alleged lack of notice of the particulars and substance in the NPRM—and would in any event not satisfy PHMSA's obligation under the Pipeline Safety Laws to make its risk assessment for its proposals available for public and GPAC

[525] Senator Cruz et al. at 7 – 8.
[526] GPA Midstream et al. at 33 – 34; INGAA et al. at 50 – 51.; Kinder Morgan, Inc. at 31 – 32.

review.[527] Other commenters also criticized PHMSA's development of the NPRM as exhibiting "improper influence" by Administration political personnel and environmental/public safety advocacy organizations[528] whom they characterize as being responsible for certain changes in the NPRM and its supporting documents during interagency review required under E.O. 12866 as amended by E.O. 14094.[529]

PHMSA Response

PHMSA complied with all APA requirements. PHMSA's NPRM and its supporting documents described with precision the form (in the NPRM's draft regulatory text) and function (in the section-by-section analysis in section V of the NPRM) of its proposed regulatory amendments in this rulemaking. In arriving at those proposals, the NPRM and its accompanying documents (the PRIA and DEA) provided particularized, lengthy discussions of its reasoning and the supporting safety, environmental, and economic analysis, data, and methodologies. The NPRM and its supporting materials prompted extensive comment and discussion, which is captured in the administrative record— including thousands of comments and seven days' of GPAC discussion on the nuances of the rulemaking's proposals and their supporting economic, environmental, safety analyses and evidence. The final rule (at section III) and its supporting documents (Appendix C to the RIA; Appendix A of the EA) contain detailed responses to those

[527] GPA Midstream et al. at 33 – 34; GPA Midstream et al. Supplemental Comments at 15; Kinder Morgan, Inc. at 31 – 32; AGA et al. at 4, "Comments on Meeting of the GPAC on Gas Pipeline Leak Detection and Repair Rule" 4 (PHMSA-2024-0005-0387) ("AGA et al. Supplemental Comments").

[528] Senator Cruz et al. at 2, 7.

[529] Senator Cruz at 2; LA Attorney General et al. at 4. E.O. 12866, "Regulatory Planning and Review" 58 FR 51735 (Oct. 4, 1993); E.O. 14094, "Modernizing Regulatory Review," 88 FR 21879 (Apr. 11, 2023).

comments and elaborates on the NPRM's supporting safety, environmental, and economic analysis, data, and methodologies. Although some commenters objected to PHMSA's reliance on certain data (e.g., updated 2021 IWG Social Cost of Methane values) or would have preferred that PHMSA provided additional information (e.g., quantified benefit data throughout[530]) in the NPRM, those commenters' preferences are not required by law.

Although the notice was sufficiently specific and well explained, the final rule resolves many of commenters' specific notice concerns as PHMSA ultimately did not expand the scope of the rulemaking to address issues on which the NPRM had solicited comment but did not specifically propose requirements for. And although the final rule contains a number of adjustments to the NPRM, the content of the NPRM and its supporting documents was more than adequate in ensuring "reasonable member[s] of the regulated class . . . [could] anticipate" the potential for those changes.[531] Nor, moreover, does PHMSA understand the adjustments in the details of the rulemaking's contents to require re-submission of a risk assessment for public comment and GPAC consultation. Industry comments advancing this position identify neither statutory text nor legislative history of PHMSA's risk assessment (49 U.S.C. 60102(b)) and GPAC consultation requirements (49 U.S.C. 60115) supporting their reading that any logical outgrowth of PHMSA proposal prompts a carousel of risk assessment updates and GPAC

[530] PHMSA addresses this criticism in greater detail in its response to Legal Comment #8.

[531] See, e.g., Telesat Canada vs. FCC, 999 F.3d 707, 713-14 (D.C. Cir. 2021) (quoting Allina Health Services vs. Sebelius, 746 F.3d 1102, 1107, 1109 (D.C. Cir. 2014). Much of PHMSA's adjustments track specific regulatory changes recommended by the GPAC and industry representatives in their initial and post-GPAC comments, demonstrating that those changes were in scope.

consultations. Indeed, 49 U.S.C. 60102(b)(4)(C)(iii) contemplates that PHMSA can update its risk assessment and rulemaking contents in the final rule is evidence to the contrary.

PHMSA strongly rejects allegations that the proposed rule was "incomplete, biased, and defective" because PHMSA met "disproportionately" with certain stakeholders. In fact, PHMSA repeatedly consulted a broad group of stakeholders, including industry representatives and state partners, throughout the development of this rulemaking.[532] PHMSA held public meetings on this rulemaking and on implementation of Section 114 of the PIPES Act of 2020, during which industry members provided extensive presentations that informed PHMSA's development of this rule.[533] Any stakeholder can track PHMSA's progress on this rulemaking, which has been publicly available on the Office of Information and Regulatory Affairs (OIRA) Unified Agenda since 2021 and is the subject of monthly updates posted to PHMSA's website.[534] Any stakeholder could have requested a meeting through OIRA in accordance with E.O. 12866 section 6(b)(4) while PHMSA's NPRM was undergoing interagency review, and several stakeholders requested such meetings.[535] But no pipeline operators or pipeline industry trade associations made such a request.[536]

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532 Summaries of those meetings are maintained on the docket for this rulemaking.

533 88 FR 31890 at 31924 – 25.

534 OIRA Unified Agenda, available at https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202310&RIN=2137-AF51. In addition, monthly updates to Office of Pipeline Safety rulemaking mandates is on PHMSA's website. *E.g.*, Monthly PIPES Act 2020 Web Chart for July 2024, available at https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2024-07/2024%20June%20%20PIPES%20Act%20Chart.pdf.

535 OIRA maintains a public-facing website through which interested parties may request a meeting to discuss issues on a rule under review: https://www.reginfo.gov/public/do/eo/neweomeeting.

536 https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202304&RIN=2137-AF51.

The claim that the White House exercised "improper influence" over development of NPRM reflects a simple misunderstanding of the E.O. 12866 redline that PHMSA uploaded to the public docket. The E.O. 12866 redline tracks all changes to the draft NPRM throughout the four-month E.O. 12866 review period. During this period, PHMSA chose to make several changes based on its own ongoing review of the draft NPRM,[537] as well as in response to questions and comments from those who reviewed the draft NPRM through the E.O. 12866 process. Allegations that statements in the NPRM were added by OIRA, and not PHMSA, demonstrates a similar misunderstanding regarding the interagency review process. PHMSA must adhere to the procedural requirements of E.O. 12866, and must submit all significant rulemakings for review by OIRA and, through the E.O. 12866 process, other Federal agencies. But PHMSA is ultimately responsible for the content of its proposed and final rules.

8. Comments alleging that PHMSA violated its procedural obligations under the Pipeline Safety Laws and Administrative Procedure Act—Risk Assessment Cost Benefit Justification

Summary of Public Comments

A number of stakeholders submitted comments contending that PHMSA's risk assessment did not support the "reasoned determination" required by 49 U.S.C. 60102(b)(5) that the benefits of each standard proposed in the NPRM justified its costs or the "reasoned decisionmaking" required under the APA.[538] Different stakeholders advanced various permutations on this line of

[537] For example, PHMSA revised its draft NPRM based on questions raised in oral arguments before the D.C. Circuit in GPA Midstream v. DOT.

[538] Commenters style their arguments here as arising under one or both of the APA and the Pipeline Safety Laws. PHMSA's response to those comments is formulated largely in terms of compliance with the Pipeline Safety

argument, among them were criticisms suggesting alleged omission of miscellaneous quantified data on costs and benefits;[539] alleged overreliance on non-quantified benefits in evaluating the costs and benefits of the rulemaking;[540] alleged inappropriate reliance on the subject matter expertise of PHMSA personnel in development of key assumptions in the risk assessment;[541] and recommendations that PHMSA's risk assessment should have incorporated a rigid "cost-effectiveness" component.[542] Commenters contend that as a result of these deficiencies in its risk assessment, PHMSA is able to "cook the books" to "make [its] cost-benefit analysis come out however it wants . . . ."[543]

PHMSA Response

PHMSA disagrees with the above criticisms of the risk assessment supporting the rulemaking. Neither the APA nor OMB and DOT implementing guidance predicate agency decisionmaking on a fully-quantified cost-benefit analysis. Instead, the APA and OMB and DOT implementing guidance encourage agencies to exercise flexibility to rely on the best available

Laws because compliance with those "more specific and . . . more demanding" procedural requirements will generally ensure compliance with APA requirements and cost-benefit principles in OMB and DOT implementing guidance. Interstate Natural Gas Ass'n of Am. v. PHMSA, No. 23-1173, slip op. at 3 (D.C. Cir. Aug. 16, 2024) ("To impose a new standard, PHMSA must publish two cost-benefit analyses: one when it first proposes the standard, and another when it finalizes the rule. . . . Before finalizing the rule, PHMSA must consider the advisory committee's recommendation; "comments and information received from the public"; and other factors, such as the "reasonableness of the standard." Id. § 60102(b)(2). In addition, PHMSA must again explicitly consider costs and benefits when issuing the final standard. . . .").

[539] PHMSA addresses specific criticisms along these lines in Appendix C to the RIA.

[540] LA Attorney General et al. at 4, 7; GPA Midstream et al. 3 and 9 – 10; GPA Midstream et al. Supplemental Comments at 10; Industry Trades at 46 – 47.

[541] GPA Midstream et al. at 22, 27; INGAA at Exhibit A pgs. 16 – 18.

[542] Kinder Morgan, Inc. at 6; INGAA at 1; Industry Trades at 45.

[543] Landry et al. at 5.

data when appropriate and to consider non-quantifiable costs and benefits when necessary.[544] The APA, moreover, contemplates that agencies need not wait to have a perfect data set to support their decisionmaking, as courts have held that agencies can adopt "prophylactic rules to prevent potential problems before they arise . . . an agency need not suffer the flood before building the levee."[545]

And although the Pipeline Safety Laws' risk assessment requirements at 49 U.S.C. 60102(b) can be read to encourage quantification of benefits and costs where appropriate, the statutory text does not require quantification of all costs and benefits, regardless of the quality of data or the level of uncertainty. Congress similarly omitted from its revisions to 49 U.S.C. 60102(b) explicit mention of "cost-effectiveness" from each of the decisionmaking factors listed at 49 U.S.C. 60102(b)(2), the risk assessment content requirements at 49 U.S.C. 60102(b)(3), and the decisional benefit/cost justification decisional language at 49 U.S.C. 60102(b)(5). Nor does current OMB guidance identify a "cost-effectiveness" framework as superior to PHMSA's approach in this rulemaking. The most recent version of OMB Circular A-4 contemplates that agencies can perform "cost-effectiveness" analyses, but explicitly encourages a "benefit-cost analysis" as the "typically more informative analytical approach" of the two approaches, particularly when the agency considers non-quantified benefits and costs.[546] Instead, 49 U.S.C.

[544] National Assn of Homebuilders vs. EPA, 682 F.3d 1032, 1039-40 (D.C. Cir. 2012). OMB, "Circular A-4" at 2-3 (Nov. 9, 2023); DOT, Order 2100.6A, "Rulemaking and Guidance Procedures" at ¶10(e) (June 7, 2021). Each of those APA-implementing guidance documents also explicitly disclaims a judicially-enforceable cause of action arising from an agency's alleged non-compliance with their contents. See E.O. 12866 at Section 10; DOT Order 2100.6A at ¶20.
[545] Stillwell v. Office of Thrift Supervision, 569 F.3d 514, 519 (D.C. Cir. 2009).
[546] Circular A-4 at 4, 5 – 7.

60102(b)(2)(C) – (D) employs less precise language that PHMSA's risk assessment must be based on merely "reasonably identifiable or estimated" benefits and costs.[547] The risk assessment, moreover, is only one of a number of factors that Congress, in 49 U.S.C. 60102(b)(2), directed PHMSA to consider when issuing regulations; that provision also obliges PHMSA to consider all "relevant available gas pipeline safety information . . . and environmental information," the reasonableness/appropriateness of a standard, as well as the public comment and GPAC recommendations. Within that broad universe of inputs to PHMSA's decision making on a rulemaking—many of which do not lend themselves to quantification or detailed predictions—imprecision and uncertainty are unavoidable.[548] This same concern also militates against a mechanical evaluation of the "cost-effectiveness" of some or all of the final rule along the lines suggested by industry commenters. Many of the environmental and public safety benefits of the rulemaking inhibit reduction to quantified values for inputs into a "cost-effectiveness" framework. A rigid "cost-effectiveness" framework would also neglect other considerations (e.g., implementation of statutory rulemaking mandates; timing of any benefits accrued; the mutually-reinforcing character of elements of PHMSA's regulatory regime) informing PHMSA's rulemaking. The legislative history of 49 U.S.C. 60102(b) reveals Congress acknowledged that perfect or complete quantification would not always be possible in adopting

[547] The courts have acknowledged that PHMSA's risk assessment can evaluate qualitative discussions of benefits against quantified costs when it provides an explanation for the unavailability of quantified data. GPA Midstream v. DOT, 67 F.4th at 1197.

[548] S. Rep. 104-334, at 3 (July 26, 1996) ("The Committee fully recognizes that all benefits and costs cannot be quantified with precision and consequently S. 1505 does not prevent the consideration of unmeasurable benefits and costs.").

language at 49 U.S.C. 60102(b)(5) reinforcing PHMSA's flexibility in determining whether the costs and benefits of a particular rulemaking standard were "justified", rather than choosing more precise language reducing its decisionmaking to a mechanical determination of whether or not quantified benefits outweighed or exceeded quantified costs.[549] Congress also included savings language in 49 U.S.C. 601012(b)(5) recognizing that PHMSA's decisionmaking on a rulemaking could also be driven by statutory mandates.[550]

PHMSA has in the final rule and its supporting documents demonstrated that the benefits of the rulemaking justify its costs as required by 49 U.S.C. 60102(b)(5). As explained in PHMSA's responses to Legal Comment #4, the core of this rulemaking implements a Congressional mandate under section 113 of the PIPES Act of 2020 for leak detection, grading, and repair regimes for certain gas pipeline facility operators and extending those requirements to other categories of pipeline facilities that were not explicitly included in by the mandate. Other elements consist of regulations providing clarity for gas pipeline facility operators in developing compliance regimes implementing a broadly-worded, self-executing mandate at section 114 of the same statute for operators to update the inspection and maintenance plans to "eliminate hazardous leaks and minimize releases of natural gas." In support of those and other elements of the rulemaking (some of which involve PHMSA's exercise of other statutory authorities), PHMSA in the NPRM and its supporting documents provided robust justification reflecting

[549] 142:136 Cong. Rec. H.11356 (Sept. 27, 1997) (noting that the statutory language ultimately codified at 49 U.S.C. 60102(b) was a "compromise" from earlier legislation passed by the House (H.R. 1323) which would have adopted at a new section 60126 much more exacting cost-benefit analysis requirements).

[550] 49 U.S.C. 60102(b)(5) (qualifying the "justification" requirement with the exclusion "Except where otherwise required by statute . . . .").

careful consideration of the factors identified in 49 U.S.C. 60102(b)(2). In the final rule, PHMSA is adopting most of those proposals—but with a number of revisions to the particulars and enhancement of its supporting technical and economic analyses in response to feedback received from stakeholders, the recommendations and discussion during the GPAC meetings, and further input from PHMSA subject matter experts[551] of "relevant available" pipeline safety and environmental information. PHMSA's justification of its decision making with respect to the universe of pertinent gas pipeline facilities (including 2.7 million miles of gas transmission, distribution, and gathering pipelines; 403 underground natural gas storage facilities; and 165 liquefied natural gas facilities) reflects careful consideration of the factors listed in 49 U.S.C. 60102(b)(2), and refinement of its policy determinations and analyses accordingly.

The cost-benefit information PHMSA provided in its risk assessment for consideration by public commenters and the GPAC satisfied the requirements under the Pipeline Safety Laws, as does the modified risk assessment that supports the final rule. In both the PRIA (section 3) and RIA (Appendix A), PHMSA explained its bases for assumptions regarding baseline compliance by affected operators, grounding them in one or more of the following data sets reflecting the

[551] PHMSA disagrees with commenters' frequent criticism of reliance on the judgment of PHMSA subject matter experts, many of whom have long academic or work experience in their field (e.g., either as a regulator of gas pipeline facilities at PHMSA or another regulatory authority and/or prior experience as an employee of gas pipeline facility operators). PHMSA as a matter of law is entitled to rely on the expertise of its personnel in understanding the current practices and potential impacts on jurisdictional gas pipeline facilities. *E.g.*, Office of Communication of United Church of Christ v. FCC, 707 F.2d 1413, 1440 (D.C. Cir. 1983) (holding that "cost benefit analyses epitomize the types of decisions that are most appropriately entrusted to the expertise of the agency"); Hüls Am. Inc. v. Browner, 83 F.3d 445, 452 (D.C. Cir. 1996) (an agency is entitled to an "extreme degree of deference" from a reviewing court that is evaluating scientific data within the agency's technical expertise). Appendix C to the RIA responds to specific examples of criticism of its reliance on the judgment of its own experts.

best "available" information to PHMSA: the judgment of PHMSA subject matter experts; annual report data pertaining to the number of gas pipeline facilities subject to the rulemaking; surveys of related federal and state requirements; review of pertinent industry consensus standards and compliance strategies (including, but not limited to, the GPTC Guide); statements and commitments by industry itself regarding existing practices among operators regarding leak detection/grading/repair and blowdown mitigation; and feedback on the NPRM's proposals from the GPAC and other stakeholders. PHMSA expanded its discussion of its baseline assumptions in the RIA in response to comments received on the PRIA and where appropriate to address uncertainties or variability has employed deliberately conservative values and sensitivity analyses. And where there remains uncertainty regarding baseline compliance levels notwithstanding the "available" information discussed above, PHMSA in the RIA acknowledges those uncertainties and explains why they do not disturb PHMSA's determination that each element of the rulemaking is justified. PHMSA's responses to specific criticisms of its baseline compliance assumptions can be found in Appendix C to the RIA.

PHMSA also provided in each of the PRIA (section 4) and RIA (section 4) quantified projections of incremental compliance costs itemized by each element of the rulemaking, and for each category of pipeline facility subject to those requirements. Those projections incorporate the best information available to PHMSA in arriving at "reasonably identifiable or estimated" costs including (but not limited to) the following: estimates and assumptions employed by PHMSA subject matter experts; information submitted by pipeline operators themselves in rate proceedings; and feedback from the GPAC and stakeholders on the PRIA and the NPRM.

PHMSA has also expanded its discussion of its incremental cost values and assumptions in the RIA in response to comments received on the PRIA and has employed conservative values and sensitivity analyses where appropriate. Nonetheless, where uncertainties continue to inhibit meaningful quantification of incremental compliance costs, PHMSA has either attempted to describe those costs qualitatively or acknowledged any residual uncertainty in the RIA—to include an explanation regarding whether and how that uncertainty is significant enough to call into question whether a specific element of the final rule was justified. PHMSA in Appendix C to the RIA responds to specific criticisms of the PRIA, such as baseline compliance assumptions and incremental compliance costs.

PHMSA's use of quantified benefits alongside qualitative benefits to "justify" the rulemaking are consistent with procedural requirements of the Pipeline Safety Laws.[552] PHMSA expended considerable effort in quantifying "reasonably identifiable or estimated" benefits arising from avoided emissions from leaks and from blowdowns on each category of gas pipeline facility subject to the rulemaking based on the expertise of its technical experts, data from state regulators and other Federal agencies and information obtained from industry stakeholders and vendors during public meetings. And as explained in section 5 and Appendix A of the final RIA, PHMSA employed a variety of measures—including adjustments to numerical inputs, sensitivity analyses and reliance on conservative assumptions—to reflect information (e.g., on leak incidence and emissions from leaks; efficacy of leak detection technologies, updated discount

[552] This approach has also been endorsed by courts applying the APA. *See, e.g.*, Nicopure Labs v. FDA, 266 F. Supp. 3d 360, 403 – 07 (D.D.C. 2017).

rates and Social Cost of Methane values, etc.) obtained from industry stakeholder comments, GPAC recommendations and discussion, and updated information from other federal agencies. Although some commenters disagree with PHMSA's selection of certain inputs (e.g., use of the Social Cost of Methane; choice of discount rates) in its calculations, PHMSA explains in section 5 and Appendix A of the RIA that it has determined those inputs—which reflect the considered opinion of subject matter experts and economists in the U.S. Federal government, and leverage recent, peer-reviewed scientific and economic literature—are the best available information for use in this rulemaking's benefits analysis. PHMSA's responses to specific criticisms of its assumptions and methodologies in quantifying benefits from the rulemaking can be found in Appendix C of the RIA and the response to Legal Comment #4 above.

PHMSA's evaluation of qualitative benefits alongside quantified costs and benefits is consistent with the Pipeline Safety Laws and the APA. As explained above, the broad universe of information Congress has demanded from PHMSA's rulemakings does not always lend itself to quantification. As explained in the RIA at section 5, this is the case for some of the public safety and environmental benefits—or more precisely, the incremental reduction in public safety and environmental risks—anticipated from the final rule. Some of those public safety benefits of the rulemaking (e.g., including incremental reduction of safety risks associated with high-consequence, low frequency pipeline facility incidents resulting from leak degradation, or reduction of second-order public safety consequences from climate change such as increased flooding causing damage to pipeline infrastructure) involves the interplay of complex engineered systems, and natural and biological processes that each do not lend themselves to quantification with meaningful precision.[553] Similar limitations inhibit quantification of some of the environmental benefits (e.g., reduction of risks to flora and fauna from exposure to, or accumulation of, hazardous constituents associated with leaks or blowdowns from unprocessed natural gas pipelines) of the rulemaking. Attempts to superimpose algorithms over such processes would necessarily employ myriad assumptions that may or may not be representative of factors (including, but not limited to, the category of gas pipeline facility; pipeline-specific operational parameters and history; and environmental conditions) materially contributing to those risks across the various of gas pipeline facilities subject this rulemaking. In recognition of these data availability constraints and uncertainty, PHMSA in each of the PRIA (at section 5) and RIA (at section 5) provided illustrative long-term historical data of quantifiable public safety and environmental consequences (e.g., release volumes, injuries, etc.) from incidents on different categories of gas pipeline facilities. PHMSA also in each of the PRIA (sections 5.6 and 6) and RIA (section 5.6) acknowledges and discusses the uncertainties inherent in consideration of non-quantified public safety and environmental benefits of the rulemaking, and in Appendix C to the RIA addresses stakeholder criticisms of its evaluation of those benefits in the PRIA.

[553] NTSB reports and PHMSA enforcement actions routinely find that incidents on gas pipeline facilities resemble failures on other complex systems in that there is often not a single root cause; rather, there is often a convergence of multiple contributing factors (each a "but for" cause of the incident) that inhibit attribution of incremental, quantified benefits to specific regulatory revisions directed toward addressing one or more identifiable contributing factors. See, e.g., NTSB, PAR-19/02, "Accident Report: Overpressurization of Natural Gas Distribution System Explosions, and Fires in Merrimack Valley, Massachusetts – Sept. 13, 2018" at 48 – 49 (2019).

9. *Comments alleging that PHMSA violated its procedural obligations under the Pipeline Safety Laws—demonstration of appropriateness*

Summary of Public Comments

PHMSA received a number of comments alleging that it had failed in the NPRM to satisfy requirements at 49 U.S.C. 60102(b)(2)(B) – (G) of the Pipeline Safety Laws to demonstrate that various NPRM proposals were "appropriate" based on their cost-effectiveness, practicability, reasonableness, and technical feasibility. Frequently those comments alleged that PHMSA had failed to make the requisite showing of appropriateness with respect to particular categories of gas pipeline facilities that would be subject to proposed requirements. PHMSA received comments along those lines from representatives from each of the following: the gas gathering industry, which alleged that PHMSA had failed to account for the distinguishable (and allegedly more limited) ability of gas gathering pipeline operators to pass along compliance costs arising from the rulemaking or the novelty of PHMSA regulation for Type C gas gathering lines in particular;[554] representatives of industry associated with non-methane part 192 gases, who alleged that PHMSA had failed to demonstrate the appropriateness of application of leak detection, grading, and repair requirements to their facilities;[555] and representatives of part 192-

[554] *E.g.*, GPA Midstream et al. at 24, 26, 30. As discussed above, PHMSA established the category of "Type C gas gathering pipelines" in late 2021 in the Gas Gathering Final Rule. Although most of the Gas Gathering Final Rule's safety requirements required compliance by May 2023, PHMSA issued an enforcement discretion allowing smaller, lower-risk Type C gas gathering pipelines an additional year to come into compliance with the entirety of the Gas Gathering Final Rule's safety requirements. PHMSA, "Notice of Limited Enforcement Discretion for Particular Type C Gas Gathering Pipelines" (July 2022).

[555] *E.g.*, Air Liquide at 8 – 9, (PHMSA-2021-0039-23498); Clean Hydrogen Future Coalition at 3 – 4 (PHMSA-2021-0039-25516); NiSource at 16 (PHMSA-2021-0039-25944); Texas Pipeline Association at 7 March 25, 2024 GPAC Transcript at 240 et seq.

regulated underground natural gas storage facilities and part 193-regulated LNG facilities, who forwarded similar criticisms of the NPRM's proposed requirements to their facilities.[556] Some State Attorneys General also called into question whether PHMSA itself had made any preliminary findings of "appropriateness," as they attributed language in the NPRM making such a preliminary finding to the Office of Information and Regulatory Affairs (OIRA) rather than PHMSA.[557] Lastly, multiple commenters criticized PHMSA's suggestion that the period of time between issuance of the NPRM and subsequent compliance timelines could inform PHMSA's "appropriateness" determinations.[558]

PHMSA Response

PHMSA disagrees; in connection with each of the principal elements of the NPRM, it made specific, preliminary conclusions regarding the indicia (cost-effectiveness, practicability, reasonableness, and technical feasibility) of "appropriateness" of those elements to different categories of pipeline that would be subject to its requirements. Those preliminary conclusions were individualized and supported by reference to a number of pertinent inputs to each of its preliminary findings. Those preliminary findings were, moreover, PHMSA's own determinations rather than language imposed by OIRA or any other reviewers during the interagency review process required under E.O. 12866. PHMSA's cover sheet showing changes introduced in the

[556] *E.g.*, Industry Trades at 115 – 20, 155-56; Kinder Morgan, Inc. at 15, 30 – 31, Mar. 25, 2024 GPAC Transcript at 240 et seq. Industry Trades also contended (at 49 and 116) that in imposing maintenance standards for LNG facilities, PHMSA would need to demonstrate that it considered certain additional factors set forth in 49 U.S.C. 60103(d).

[557] LA Attorney General et al. at 4.

[558] See, e.g., Industry Trades at 148; Kinder Morgan, Inc. at 7 – 8.

NPRM during interagency review memorializes any changes made by PHMSA—which, as described above, is alone responsible for the content of its proposed and final rule—of its own accord or in response to reviewers (without differentiation between the source of the suggestion) through the E.O. 12866 process. The factors PHMSA considered to make its preliminary findings included (but were not limited to) the technical discussion of each proposal in the NPRM preamble; analysis of the costs and benefits of those proposed requirements in the PRIA; corresponding discussions of the potential environmental risks and benefits in the DEA; PHMSA's understanding of current operator practices as described in the NPRM and PRIA; similitude to existing state and PHMSA requirements; the relationship of each proposed requirement to other proposed elements (including any compliance flexibilities) elsewhere in the rulemaking; the presence of statutory mandates; and compliance timelines. Gas pipeline facilities cannot (consistent with the caselaw cited by industry commenters) be subject to NPRM proposals until PHMSA has formally adopted those proposed regulatory amendments in a final rule. However, PHMSA references the date of publication of the NPRM's proposals for a different purpose: the ensuring time period is one of several data points speaking to factors (e.g., reasonableness, practicability) indicative of the ability of affected operators (who at the NPRM stage would have notice of PHMSA's preferred approach for implementing that statutory mandate) to comply with the rulemaking's requirements.

The final rule's discussion of each of its principal elements builds on and refines those preliminary conclusions and makes final determinations regarding the indicia (cost-effectiveness, practicability, reasonableness, and technical feasibility) of "appropriateness." Those discussions explicitly note that they have been informed by comments and material (both supportive and critical) received in response to the NPRM and during the GPAC meetings, as well as updated supporting technical (in the final rule), economic (RIA), and environmental (EA) analyses in the rulemaking. Where its review of that administrative record yielded that elements of the rulemaking as proposed were not "appropriate" (by reference to cost-effectiveness, practicability, reasonableness, and technical feasibility) for certain categories of gas pipeline facilities, PHMSA has either modified the content or compliance timelines for those proposals to address the concern or declined to adopt its original proposal. And where appropriate, PHMSA in the final rule has also elaborated on NPRM statements regarding the practices of reasonably prudent operators by highlighting supporting examples (e.g., similar consensus industry standards and recommended practices, or industry voluntary practice). PHMSA addresses specific criticisms regarding appropriateness of applying the rulemaking's requirements to different gas pipeline facilities in section III of the final rule.

PHMSA similarly has considered and disagrees with comments submitted by gas gathering industry trade associations contending that PHMSA's "appropriateness" analysis and PRIA neglected consideration of those facilities' distinguishable (non-utility) regulatory model that they contend inhibits their ability to bear compliance costs associated with the rulemaking. Although PHMSA acknowledges that gas gathering pipeline operators will generally not be entitled to recourse rates pursuant to utility (i.e., cost-of-service) regulation for the transportation services they provide, utility regulation is far from the only means for a pipeline to recover its regulatory compliance costs; even unsophisticated entities can negotiate with counterparties to employ a variety of commonly-employed contractual mechanisms (e.g., force majeure provisions; cost escalation provisions; limited contractual duration/periods) to facilitate the timely recovery of any new compliance costs imposed by PHMSA or other regulators. Industry commenters do not explicitly acknowledge this contingency, but rather seem to suggest that the gas gathering pipeline operators are never able to recover new incremental compliance costs from new regulations. Even if it were true that gas gathering operators would themselves have to bear all incremental compliance costs of this rulemaking, industry commenters have provided no meaningful data (e.g., identification of the number of Type C gas gathering pipelines and information regarding their revenues and affiliate relationships; revenue data across all gas gathering pipeline facilities) to be evaluated against costs in a way that could demonstrate that any costs from this rulemaking would be overly burdensome for most or even a large portion of affected gas gathering pipeline operators.[559] Nonetheless, in recognition of this potential constraint, in both the Interim Regulatory Flexibility Analysis (see PRIA at section 7.5) and Final Regulatory Flexibility Analysis (see RIA at section 7.5) PHMSA employed a sensitivity analysis assuming a lower (50%) rate of cost recovery for all categories of part 192-regulated gas gathering pipelines. Even with that conservatism employed, the great majority—roughly 70%—of all pipeline operators (including gas gathering pipeline operators) would bear incremental compliance costs not exceeding 1% of their annual revenues, with an even smaller share (around 10%) of pipeline operators that would incur compliance costs that are a significant (>3%) portion of their annual revenues. After considering commenter input, the final RIA also provides data on

[559] PHMSA also addresses these arguments in Appendix C to the RIA.

estimated incremental costs to each of the Type A, B, and C gathering line segments from the applicable provisions in the final rule (RIA section 4.1), along with a sensitivity analysis that estimates the impact of exempting Type C and offshore gathering lines from the rule as a whole (section 6.6.2). Additionally, many of those gas gathering pipelines are corporate affiliates of other (midstream) part 192-regulated gas pipeline entities (demonstrated by annual report data for offshore and Types A, B, and C gas gathering pipelines), just as they made have an affiliate relationship with (upstream) production-related oil and gas entities; aggregate compliance costs could therefore be lower than PHMSA's assumptions for those gas gathering facilities should operators employ cross-affiliate compliance strategies, and any costs would be borne across a larger revenue base.

PHMSA also disagrees that extension of some or all of the final rule's requirements to Type C gas gathering lines in particular would not be appropriate because those facilities were only recently subject to any PHMSA safety and reporting requirements. As explained at greater length in the NPRM (at sections II.C and D) and the final rule (at sections III.B and P), Type C gas gathering pipelines—which are a large portion of the total gas gathering pipeline mileage subject to part 191 reporting requirements and the majority of gas gathering pipeline mileage subject to part 192 safety requirements[560]—are substantial contributors to greenhouse gas emissions and entail particularly acute public safety and environmental risks because they transport unprocessed natural gas at high operating pressures and relatively high throughput capacity levels. Although PHMSA granted smaller, lower-risk Type C gathering lines an

[560] RIA table 3-1.

enforcement discretion extending by one year (until May 2024) compliance timelines for most safety requirements in the 2021 Gas Gathering Final Rule, it granted that enforcement discretion to facilitate timely operator compliance with those requirements and to prioritize limited PHMSA and state enforcement resources on the highest-risk Type C pipelines; the enforcement discretion was in no way intended to shield those pipelines from future PHMSA regulatory requirements. Additionally, as explained in sections III and IV of the final rule, PHMSA has adopted a number of changes to the reporting, leak detection, grading and repair requirements (and associated compliance timelines) pertinent to Type C gas gathering pipelines in part to facilitate Type C gas gathering pipelines' timely and meaningful compliance with the final rule's requirements. Those revisions inform PHMSA's determinations that the final rule's reporting and leak detection, repair, and grading requirements should apply to Type C gas gathering pipelines.

Lastly, PHMSA disagrees that its statutory authority to impose maintenance and operations requirements for LNG facilities requires a threshold showing of "appropriateness" (per 49 U.S.C. 60102(b)(2)) as well as a separate showing of certain additional considerations listed in 49 U.S.C. 60103(d). Those latter considerations (including conditions and features of facility equipment and structures; existing fire prevention and containment equipment) inform PHMSA's exercise of its subject matter expertise in making findings required by 49 U.S.C. 60102(b)(2), (b)(3)(D), and (b)(5) regarding the technical feasibility, practicability, reasonableness, and cost-effectiveness of proposed standards. Historical PHMSA rulemakings introducing and subsequently amending maintenance requirements at 49 CFR part 193, subpart

G describe evaluation of proposed standards against 49 U.S.C. 60102(b)(2) factors.[561] This reading is supported by the legislative history of 49 U.S.C. 60103(d). In introducing that and other LNG-focused statutory provisions 1979 to address a regulatory gap regarding the safety LNG facilities, Congressional reports underscored that the maintenance requirements introduced by PHMSA's predecessor (the RSPA) needed to be fit-for-purpose given the variety of LNG facilities (many of them with sound safety records) that would be subject to meaningful Federal maintenance requirements for the first time.[562]

10. Comments alleging that PHMSA violated its procedural obligations under the Pipeline Safety Laws—risk assessment evaluation of alternatives

Summary of Public Comments

PHMSA received a number of comments alleging that it violated procedural requirements at 49 U.S.C. 60102(b)(3) requiring consideration of alternatives within its risk assessment.[563] Although those criticisms appear in different permutations, among them are allegations that PHMSA did not adequately evaluate alternatives to one or more specific elements of the rulemaking; that PHMSA did not comply with best practices for the consideration of alternatives set forth in OMB Circular A-4; and that PHMSA did not consider non-regulatory alternatives to

[561] *E.g.*, RSPA, "Final Rule: Liquefied Natural Gas Facilities- Federal Safety Standards,"45 FR 70390 (Oct. 23, 1980) (addressing only 49 U.S.C. 60102(b)(2) factors). To the extent that those PHMSA rulemakings have explicitly addressed the factors at 49 U.S.C. 60103(d), they have construed them as evincing Congress's intent for PHMSA to issue maintenance requirements on those topics. *E.g.*, RSPA, "Final Rule: Liquefied Natural Gas Facilities; Clarifying and Updating Safety Standards," 49 FR 11330, 11332 (May 10, 2004) (characterizing the 49 U.S.C. 60102(d) considerations as grants of authority rather than mandatory showings or findings).

[562] H. Rept. 96-201 at 20, 23-24 (May 15, 1979).

[563] *E.g.*, Kinder Morgan, Inc. at 16, 32; GPA Midstream et al. at 2 – 3 and 9; Industry Trades at 47 – 48.

different elements of the rulemaking. Although some commenters submitted their own preferred alternative regulatory text or approaches along with their comments on the NPRM, other commenters did not themselves always identify specific alternatives PHMSA should have considered.

PHMSA Response

PHMSA's consideration of alternatives to its proposals in the NPRM is consistent with applicable law. Commenters are correct that the Pipeline Safety Laws at 49 U.S.C. 60102(b)(3) require that PHMSA identify both "regulatory" and "non-regulatory" alternatives to its proposals within an NPRM, but both the statutory text and pertinent legislative history underscore that discussion within PHMSA's risk assessment of those alternatives is not intended to be exhaustive. Indeed, the statutory text at 49 U.S.C. 60102(b)(3) prescribes that PHMSA's risk assessment only "identify" any such alternatives considered accompanied by a "brief explanation of the reasons" for rejecting those other options; Likewise, 49 U.S.C. 60102(b)(4)(C) requires that, following a GPAC meeting, PHMSA must "respon[d]" to any specific alternatives recommended by the GPAC. The statutory text provides no further requirements regarding the number, character, or contents of PHMSA's discussion of alternatives in its risk assessment, much less an elaboration on what is or is not a "regulatory" or "non-regulatory" alternative. This reading is supported by the legislative history of 49 U.S.C. 60102(b), which Congress adopted after rejecting alternative statutory language that would have required thorough discussion of the incremental benefits and costs of alternatives.[564] Similarly, OMB Circular A-4 avoids mandatory language in describing the number and type of alternatives agencies must consider in their economic analyses; rather, it emphasizes agency "judgment" in choosing "reasonable" regulatory alternatives meriting consideration in light of "practical limits" for the agency in performing a cost-benefit analysis.[565]

PHMSA's evaluation of alternatives in this proceeding satisfied those legal requirements of the Pipeline Safety Laws and is consistent with OMB Circular A-4. Although commenters suggest that PHMSA should have identified and discussed a universe of (largely unspecified) permutations on regulatory and non-regulatory alternatives for one or more of the dozens of the provisions in the NPRM, that reading is hard to square with Congressional statutory text and legislative history discussed above. And insofar as commenters' reading expects that PHMSA should have evaluated a series of alternatives to each of the many provisions of the NPRM, it would also yield little genuine improvement in PHMSA's decisionmaking in the rulemaking. In contrast, PHMSA's risk assessment evaluated a reasonable number of plausible options before the agency. Specifically, the PRIA at section 2.2 identified, and briefly discussed its reasons for rejecting, four alternatives considered by PHMSA in addition to the NPRM as proposed: the "no action" alternative (baseline or status quo), a pair of variations on proposed frequencies for

[564] 142:136 Cong. Rec. H.11356 (Sept. 27, 1997) (noting that the statutory language ultimately codified at 49 U.S.C. 60102(b) was a "compromise" from earlier legislation passed by the House (H.R. 1323) which would have adopted at a new section 60126 much more exacting risk assessment requirements with respect to evaluation of alternatives).

[565] OMB Circular A-4 at 21. And although OMB Circular A-4 is informative regarding the discussion of alternatives within PHMSA's risk assessment, neither the Pipeline Safety Laws nor PHMSA regulations codify its contents, and E.O. 12866 (which OMB Circular A-4 elaborates) is not judicially enforceable. E.O. 12866 at Section 10.

leakage surveys on gas distribution pipelines, and evaluation of whether to extend proposed leak detection, grading, and repair to gas transmission compression and gas gathering boosting stations. PHMSA's NPRM also identified specific topics on which it would consider stakeholder feedback that could inform additional alternatives. Two of the alternatives discussed in the PRIA, moreover, employ "non-regulatory" approaches in response to the public safety risk and environmental harms identified in the NPRM. The "no-action" alternative identified in the PRIA would, of course, impose no new regulatory requirements at all. Rather, the "no action" alternative would instead rely on voluntary operator actions and existing state and Federal regulations that the NPRM (at section II) and PRIA (at section 1.1) explain results in substantial public safety and environmental hazards from all gas pipeline facilities; it would also fail to satisfy the statutory mandate in section 113 of the PIPES Act of 2020 to introduce new leak detection, grading, and repair requirements. But PHMSA's preferred alternative (the NPRM as proposed) in fact employs non-regulatory approaches. The NPRM contains a number of elements (e.g., the exception at 192.703(d) from PHMSA leak detection, repair, and grading criteria for certain compressor and boosting stations; employment of § 192.18 notification machinery throughout its proposals; and the "menu" of options for blowdown emissions mitigation at each of §§ 192.770 and 193.252) eschewing command-and-control, one-size-fits-all regulatory requirements in favor of a flexible, operator-led approach. The limited application and distinguishable content for various proposed requirements (e.g., omission of underground natural gas storage and LNG facilities from comprehensive leak detection, grading, and repair requirements; limited application of enhanced reporting requirements to Type R gas gathering pipelines) similarly reflect a deliberate decision by PHMSA to integrate non-regulatory approaches within its preferred alternative.

Nonetheless, in response to public comments PHMSA's final rule builds on earlier discussions of alternatives in PHMSA's proposed rulemaking. Section 2 of the RIA doubles the number of alternatives identified and discussed by PHMSA in response to suggested alternatives from stakeholders, other alternatives identified by PHMSA based on changes to the rulemaking's content since the NPRM, and (consistent with 49 U.S.C. 60102(b)(4)) GPAC recommendations—which themselves were the result of extended brainstorming on and discussion of potential alternatives to the NPRM as proposed. Among the newly identified alternatives is PHMSA's selected option: a revised version of PHMSA's initial proposal with changes to a number of requirements in response to stakeholder feedback on safety and cost concerns, among other things, GPAC discussion and recommendations, and specific alternative language recommended by stakeholders. That newly-preferred option, moreover, expands scope limitations and regulatory flexibilities) that demonstrate consideration of non-regulatory approaches beyond the formal evaluation of alternatives. For example, at § 192.760(d)(2) PHMSA has implemented a de minimis exception from repair requirements for small (< 5 CFH) gas leaks. The final rule and its accompanying risk assessment reflect a robust evaluation of regulatory and non-regulatory alternatives, which in turn strikes a better balance of safety/environmental benefits and compliance costs than the NPRM's proposals. This exemplifies precisely the sort of improved agency decision-making intended by Congress in adopting enhanced requirements at 49 U.S.C. 60102(b)(3) for consideration of alternatives.

11. Comments alleging that PHMSA violated its procedural obligations under the Pipeline Safety Laws—consultation with the GPAC

Summary of Public Comments

PHMSA received several comments criticizing its interactions with the Gas Pipeline Advisory Committee within the rulemaking as required by each of 49 U.S.C. 60102(b)(2) and (b)(4), as well as 49 U.S.C. 60115. Trade associations representing the gas gathering industry alleged that the GPAC's evaluation of PHMSA's risk assessment during the meetings on this rulemaking was deficient because GPAC members appointed to represent "industry" or the "public" may lack requisite expertise specified in 49 U.S.C. 60115 to perform a meaningful evaluation of PHMSA's risk assessment.[566] Those trade associations also contended that PHMSA's Designated Federal Officer (DFO) for the GPAC did not memorialize or correct certain concerns of theirs regarding PHMSA's risk assessment within materials circulated to GPAC members in advance of the meeting.[567] Those and other industry trade associations representing other categories of gas pipeline facility also demanded that PHMSA notify stakeholders—and perhaps submit for another round of GPAC review—a revised risk assessment reflecting adjustments to PHMSA's risk assessment in response to GPAC discussions.[568] Industry trade groups assert such notification must be within PHMSA's written response to the GPAC's report, and must explain "how [PHMSA] intends to respond to . . . concerns" discussed in the

[566] GPA Midstream et al. Supplemental Comments at 6 – 7 & n.28.
[567] GPA Midstream et al. Supplemental Comments at 6.
[568] AGA et al. Supplemental Comments at 3 – 4; GPA Midstream et al. Supplemental Comments at 6 – 8.

meeting, lest stakeholders be unable to engage OIRA on the risk assessment during any E.O. 12866 meetings on the rulemaking.[569]

PHMSA Response

PHMSA has considered these comments and concludes that its consultation with the GPAC in this rulemaking—which involved in-depth discussions over the course of seven full days of meetings and receipt of real-time feedback from numerous in-person attendees representing all industry sectors and members of the public—fully satisfied pertinent statutory requirements.

Criticisms of the composition and conduct of the GPAC meeting for this rulemaking are unsupported by statutory text or legislative history. Indeed, PHMSA is unaware—and comments did not identify—statutory text or legislative history related to 49 U.S.C. 60102(b) and 60115 evincing Congressional intent for PHMSA to publicly designate which of its industry or public representatives on GPAC do or do not have "risk assessment" or "cost benefit" education and experience. Neither PHMSA nor its predecessor RSPA, therefore, have made such public designations. Instead, the statute requires PHMSA to review candidate resumes and determinations regarding the qualifications of each GPAC member with respect to "risk assessment" or "cost-benefit analysis"[570]—a reasonable approach given that those broad concepts are themselves undefined in the Pipeline Safety Laws. And even though not required by

[569] AGA et al. Supplemental Comments at 4; GPA Midstream et al. Supplemental Comments at 7 – 8.

[570] With respect to members on GPAC representing the pipeline industry, the statute requires PHMSA to consult with industry trade groups in identifying candidates satisfying the statutory educational and experiential criteria. See 49 U.S.C. 60115(b)(4)(B).

statute, PHMSA posts short biographies of each of the GPAC members (many of whom have served on the GPAC for an extended period) to its public website to improve transparency and improve confidence in the expertise of GPAC members.[571] Due diligence of that and other publicly-available resources (e.g., LinkedIn) reveal requisite educational and experiential qualifications among current GPAC members representing the public and industry.[572] In addition, many of the GPAC members play critical roles in the generation and submission of their organization's or company's comments on technical, economic, and environmental issues in this and other rulemakings.

Criticisms regarding the conduct of the GPAC meeting for the LDAR rulemaking likewise evince a misapprehension of the respective roles of each of the GPAC and PHMSA (including the DFO). The GPAC is a peer review body subject to the requirements of the Federal Advisory Committee Act (Pub. L. 92-463); its function is governed by a charter and bylaws.[573] Those governing documents provide that the Committee Chairman designated for the meeting is the presiding officer of the committee and "guides all efforts in completing assigned tasks."[574]

[571] https://www.phmsa.dot.gov/standards-rulemaking/pipeline/gpac-committee-member-biographies.

[572] For example, one of the members of the GPAC representing the public whom gas gathering industry trade associations suggest lacks experience in "cost-benefit analysis" or "risk assessment" in fact wrote a law review article on those approaches within PHMSA rulemakings. See Sara Gosman, "Justifying Safety: The Paradox of Rationality," 90 Temple L. Rev. 155 (2018). Similarly, the industry members on the GPAC—several with advanced degrees in business management—are senior executives whose day-to-day decision-making regarding pipeline operation is necessarily informed by evaluation of costs/benefit and assessment of public safety and environmental risk.

[573] https://www.phmsa.dot.gov/standards-rulemaking/pipeline/pipeline-advisory-committees.

[574] Bylaws of the Technical Pipeline Safety Standards Committee and the Technical Hazardous Liquid Pipeline Safety Standards Committee ("GPAC Bylaws"), § VI. The Chairman generally leads the committee's deliberation, and the other members participate as desired within agreed-upon rules of order.

The DFO, on the other hand, serves as PHMSA's agent for the committee's activities.[575] The DFO initiates GPAC consideration of a proposed rulemaking by issuing a Federal Register notice that formally submits proposed rules (and their supporting risk assessments) to the GPAC for its consideration; proposes a broadly-worded agenda; identifies dockets in which comments have been (or can be) submitted; and provides the GPAC members and members of the public additional information (e.g., notification of the time and place for each meeting) on the meeting mechanics.[576] In advance of the meeting, the DFO proposes an agenda with the committee Chair for endorsement. Thereafter the DFO meets briefly with the GPAC members, and forwards and posts to PHMSA's public-facing website background materials summarizing the content of the rule and material comments received consistent with topics in the agenda discussed with the Committee Chair. During the meeting itself, the Committee Chair leads the conversation using PHMSA staff presentations on the proposed rulemaking and comments received as a starting point; from there, the Committee Chair consults with other members in leading the GPAC between and through different issues, adjusting the agenda based on consulting with GPAC members, PHMSA staff, and the DFO. After the meeting itself, the DFO (typically through PHMSA staff) performs various administrative tasks, such as, maintaining meeting records and the roll, preparing minutes, and preparing the annual report required under FACA.[577]

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[575] GPC Charter at § 8; GPAC Bylaws, § VI.
[576] PHMSA, "Notice—Meeting of the Gas Pipeline Advisory Committee" 89 FR 12798 (Feb. 20, 2024) (notice for the March 2024 GPAC meeting); PHMSA, "Notice—Meeting of the Gas Pipeline Advisory Committee" 88 FR 64518 (Sep. 19, 2023) (notice for the November 2023 GPAC meeting).
[577] Charter of the Technical Pipeline Safety Standards Committee, § 3.a.

Neither the Pipeline Safety Laws nor the GPAC governing documents assign the DFO responsibility for relaying specific public comments to committee members as claimed by trade associations representing the gas gathering industry. Rather, Federal Register notices announcing each meeting identify public-facing dockets containing comments on each proposed rulemaking (including its risk assessment) and state that such comments are within the scope of the materials the GPAC will review.[578] Although by convention PHMSA staff in advance of and during the meeting provide a presentation summarizing important comments on key elements of the rulemaking and its risk assessment, that presentation is required neither by statute nor the GPAC's governing documents; rather, it is provided as a courtesy to GPAC members to focus their review and discussion of the administrative record.[579] PHMSA's staff presentation also does not purport to present all information relevant to the committee members' evaluation of the proposed rulemaking and its risk assessment—including gas gathering industry concerns regarding PHMSA's risk assessment submitted in the rulemaking docket months before each of the November 2023 and March 2024 GPAC meetings.[580]

PHMSA likewise finds no support in statutory text and legislative history for industry commenters' suggestion that PHMSA must revise and re-submit its risk assessment and proposed

[578] 88 FR 64518.

[579] See 49 U.S.C. 60102(b)(4)(B), 60115(a), (c); see also GPAC Bylaws, § VI (stating that members will "gather information as necessary to discuss issues presented by the DFO").

[580] PHMSA also notes that during the meeting, representatives of the gas gathering industry highlighted their concerns regarding PHMSA's statutory authority and the adequacy of its risk assessment multiple times when the floor was opened to members of the public to speak to the proposed rule. See, e.g., Coyle, GPAC Transcript for Nov. 27, 2023 at 91; Coyle, GPAC Transcript for Nov. 28, 2023 at 413; Hite, GPAC Transcript for Nov. 28, 2023 at 67.

regulatory amendments for review by the GPAC before issuing the final rule. Indeed, the statutory text plainly provides PHMSA with the authority to update those materials to reflect comments received and GPAC discussion and recommendations without re-submission to the GPAC: 49 U.S.C. 60102(b)(4)(C) explicitly states that PHMSA "may revise" its risk assessment and proposals before promulgating the final standard; there is no statutory requirement to resubmit a revised risk assessment or proposed standard to the GPAC before issuing a final rule.[581] Although as a prudential matter PHMSA may decide to re-submit a proposal and its accompanying risk assessment for GPAC review in some circumstances (e.g., if either PHMSA's preferred rulemaking content is so different from the proposed rulemaking as to warrant a supplemental notice under the Administrative Procedure Act, or the initial risk assessment contains fatal errors that would have frustrated meaningful GPAC evaluation), PHMSA explains elsewhere in its responses to legal comments and in Appendix C to the RIA that no such circumstances were present in this rulemaking.

PHMSA also finds no support in statutory text or legislative history that PHMSA's written response to the GPAC must detail how PHMSA intends to address GPAC discussion and recommendations in a subsequent final rule. PHMSA agrees that 49 U.S.C. 60102(b)(4)(C)(ii) requires PHMSA to respond in writing to the GPAC's report. But the language Congress employed in that provision is broad and does not require the detailed response foreshadowing PHMSA's decision-making in a final rule that industry commenters contend is required; rather,

[581] In addition, the commenter reading of the risk assessment submission requirements would yield an impractical result—a "do-loop" of multiple rounds of GPAC review—that would frustrate PHMSA's ability to adopt rulemakings addressing emerging safety concerns and statutory mandates.

the statutory text requires merely that PHMSA provide a written response "concerning all significant peer review comments and recommended alternatives" contained in the GPAC's report with no specific requirements regarding the content of the response. Other provisions in the Pipeline Safety Laws corroborate PHMSA's understanding that Congress did not intend for PHMSA to reveal revisions to policy decisions and risk assessment within its written response to the GPAC; 49 U.S.C. 60102(b)(4)(C)(iii) permits PHMSA to make such revisions as the third and last step in a series of differentiated, sequential actions specified in 49 U.S.C. 60102(b)(4)(C) on receipt of the GPAC's report. Consistent with its understanding of that statutory language, PHMSA's written response to the GPAC explicitly acknowledges the GPAC's report—to include the meeting transcripts of GPAC discussion and the GPAC's explicit recommendations, and other materials—and commits to consideration and response to those discussions and recommendations (including with respect to significant comments and recommended alternatives per 49 U.S.C. 60102(b)(4)(C)(ii) in the final rule.[582] PHMSA's written response to the GPAC also addresses industry commenters' claims that they would be prejudiced in connection with E.O. 12866 meetings by noting that OIRA generally seeks to accommodate meeting requests, but they are not a matter of right for stakeholders requesting such meetings.[583]

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[582] PHMSA, "Response to the Gas Pipeline Advisory Committee's Report on the Pipeline Safety: Gas Pipeline Leak Detection and Repair Proposed Rule (2137-AF51)" (PHMSA-2024-0005-0412). PHMSA's written response to the GPAC also notes that PHMSA is restricted by OST regulation and guidance from disclosing the contents of its rulemakings and risk assessments to members of the public. PHMSA response to GPAC at 2 & n.3 (citing each of 49 CFR 5.5, DOT Order 2100.6A, and DOT's April 2022 "Guidance on Communication with Parties Outside of the Federal Executive Branch (Ex Parte Communications)").

[583] PHMSA response to GPAC at 3 & n.5.

12. Comments alleging that PHMSA violated requirements of miscellaneous statutes, including the Regulatory Flexibility Act and the Paperwork Reduction Act

Summary of Public Comments

PHMSA received comments alleging that PHMSA violated various other statutory requirements beyond the Pipeline Safety Statutes and the APA. Certain members of Congress alleged that PHMSA's proposal would violate the Regulatory Flexibility Act (RFA) due to the unfair and unnecessary burden that would be placed on a substantial portion of small entities.[584] INGAA claimed that PHMSA violated the Paperwork Reduction Act (PRA) by proposing duplicative reporting requirements for operators to file both incident reports and large-volume gas release reports where the total release volume exceeds 10% of the volume estimates.[585] Cruz et al. also suggested that the proposed repair timelines in the NPRM "potentially contradict PHMSA's own grant program and the direction of Congress" in the Infrastructure Investment and Jobs Act (IIJA).[586]

PHMSA Response

PHMSA complied with all of the requisite statutory requirements in promulgating this final rule, including the RFA and PRA (see, respectively, Section 7 of the RIA and Section V.I of this final rule preamble). First, PHMSA performed an initial regulatory flexibility analysis in the preliminary RIA in accordance with the RFA, including an estimate of the economic impact on

[584] Senator Cruz et al. at 6.
[585] INGAA et al. at 5.
[586] Pub. L. No. 117-58; Senator Cruz et al. at 8. The commenter alleged that the ten-year project reimbursement timeline under PHMSA's IIJA pipeline replacement grant program conflicts with the NPRM proposal to extend leak repair timelines up to five years for pipeline replacement projects.

small entities. PHMSA then provided the final regulatory flexibility analysis required under the RFA in the final RIA. PHMSA found that an estimated [9 to 11]% of small entities have a higher chance of facing significant economic impacts under this rulemaking. However, the RFA does not mandate that an agency abandon a rulemaking based on the estimated economic impact on small entities. Rather, as required under the RFA,[587] PHMSA considered in the RIA whether regulatory and non-regulatory alternatives could minimize the burden on small entities while achieving the objective of this rulemaking, and PHMSA took steps to assure that small entities would have an opportunity to participate in the rulemaking, including by conducting public hearings and providing multiple fora for public comments via the original comment period, two GPAC meetings, and two subsequent comment periods following those GPAC meetings. Following promulgation of this rule, PHMSA intends to publish guidance, such as frequently asked questions, that will assist small entities in complying with the rule's requirements.

PHMSA has similarly satisfied its obligations under the PRA. As PHMSA explains in Section III.L.5 of the preamble to the final rule, PHMSA agrees that the proposed requirement for operators to submit an additional large-volume gas release report with final release volume estimates would already be required under existing part 191 requirements for operators to submit supplemental incident reports. PHMSA has revised these reporting requirements in the final rule to avoid duplicative reporting.

PHMSA also disagrees that this rule's repair timelines somehow contradict the IIJA. The pipeline modernization grant program established by the IIJA does not conflict with the repair

[587] 5 U.S.C. 604(a)(6) and 609(a).

requirements proposed in the NPRM or finalized herein, and in fact the grant program can provide complementary benefits for certain distribution operators pursuing pipe replacement projects. In the IIJA, Congress appropriated one billion dollars over five years for PHMSA to make grants for modernization of municipality- and community-owned gas distribution pipelines, with a requirement that PHMSA obligate all grant funds to specified projects within 10 years. In this rulemaking, PHMSA is incentivizing pipeline replacement projects by exempting from repair requirements all Grade 3 leaks on pipeline segments scheduled for replacement (and actually replaced) within 7 years (originally proposed to be 5 years). The final rule also exempts Grade 2 leaks from repair requirements, for pipeline segments scheduled for replacement (and actually replaced) within 2 years. Eligible operators of distribution pipelines may apply for grants from PHMSA for replacement projects and may receive reimbursements for up to 13 years from the date of the IIJA[588] (which is entirely unrelated to the compliance dates of this rulemaking). Under the new leak detection and repair requirements in this final rule, these same operators may carry Grade 3 and Grade 2 leaks on the pipeline segment targeted for replacement for up to 7 or 2 years (respectively) from the date a leak is discovered, instead of being required

[588] PHMSA is required to obligate all grant funds within 10 years under the IIJA, but PHMSA will only make the actual awards in reimbursement for project expenses. PHMSA's first Notice of Funding Opportunity ("NOFO") in 2022 provided that "all awards will have a 36-month period of performance in which the grantees are expected to expend the awarded FY 2022 grant funds to complete the approved projects." PHMSA, "Frequently Asked Questions: FY 2022 Natural Gas Distribution Infrastructure Safety and Modernization Grant Notice of Funding Opportunity" (July 29, 2022), available at https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2022-08/NGDISM-NOFO-FAQs-for-Publication-Batch-1-4%202022-07-29.pdf. If PHMSA continues to use a 36-month performance period for future NOFOs, and if PHMSA obligates some grant funds at the very end of the 10-year window under the IIJA, it is possible that some operators may receive reimbursements up to 13 years from the date of the IIJA.

to repair those leaks within the default timeframes. If a project replacement is not scheduled and completed within required replacement period, the operator would be required to repair the leaks on that segment—but the operator could still be eligible to receive IIJA reimbursements if the replacement project is later completed in accordance with the terms of the modernization grant program. Thus, while these mutually-reinforcing programs may provide complementary incentives to replace leaky distribution pipeline segments, they are in no way contradictory.[589]

U. Compliance Timelines and Other General Comments

1. Summary of PHMSA's Proposal

The NPRM contained several terms related to the compliance timelines for the rulemaking: "publication date," "effective date," and "compliance date." "Publication date" refers to the date upon which a final rule is published in the Federal Register. "Effective date" refers to the date upon which the amendments to the regulations described in a final rule enter into force.[590] Sometimes an agency may define certain compliance dates separate from the effective date; the "compliance date" refers to the date upon which entities must comply with a

[589] To the extent that this argument goes to the interpretation of the requirement in Section 113 of the PIPES Act of 2020 that PHMSA "include a schedule for repairing or replacing each leaking pipe . . . with appropriate deadlines" (49 U.S.C. 60102(q)(3)(A)(iii), emphasis added), unrelated statutes that address different purposes are a particularly weak indicator of Congressional intent. *E.g.*, Firstar Bank, N.A. v. Faul, 253 F.3d 982, 991 (7th Cir. 2001) (describing reference to an unrelated statute for construction of ambiguous language as "a relatively weak aid given that Congress may well have intended the same word to have a different meaning in different statutes" that may make sense when "a court has no other solid basis for construing vague statutory language"). PHMSA instead looked to the statutory context of the PIPES Act of 2020 (specifically 49 U.S.C. 60102(q)(2)(A)) when interpreting Congress's direction to establish "appropriate" repair and replacement deadlines.

[590] Under the Congressional Review Act, rules meeting the criteria set forth in 5 U.S.C. 804(2) may only go into effect 60 days after the publication date or after a report is submitted to Congress, whichever is later. 5 U.S.C. 801(a)(3).

specific provision that has gone into effect. From the compliance date forward, PHMSA may take enforcement action for that provision. Different requirements may have different compliance dates; however, in this case, the NPRM proposed one consistent overall compliance date for all of the provisions in the NPRM.

The NPRM proposed an effective date of 6 months from the publication date of the final rule. Except for repairs of leaks existing on or before the effective date of the final rule, the NPRM did not provide separate compliance dates for any of the NPRM's other provisions. As such, the proposed effective date of the rule was also the compliance date for the proposed requirements.

PHMSA proposed repair deadlines for leaks existing on or before the effective date as follows: (a) Grade 2 leaks: 12 months after publication of the final rule, and (b) Grade 3 leaks: 36 months after publication of the final rule. For further details on the proposed repair timelines for existing leaks and the timelines adopted in this final rule, see section III.I.

Section 191.11, which existed prior to the publication of the NPRM, requires operators to submit annual reports for the preceding calendar year on or before March 15 of a given year. In the NPRM, PHMSA proposed operators must submit large-volume gas release reports for releases that become reportable on or after the effective date of the final rule. For further details on the proposed compliance timelines for other part 191 reporting requirements, see section III.L.

2. Summary of Public Comments

PHMSA received extensive comments on the proposed effective date of 6 months from the publication date of the final rule. GPA Midstream Association, et al. and INGAA urged PHMSA to consider the ongoing EPA actions when setting the effective date of this rulemaking. Hope Gas Inc. urged flexibility, as requiring all companies to transition at the same time could create resource constraints. The Joint Trades commented that an accelerated timeline would concentrate costs in a short period of time and draw resources from integrity management and damage prevention programs and recommended a compliance date of 36 months from the effective date of the rule. MDU Utilities Group expressed concern regarding the proposed effective date and noted there were certain compliance activities that could take companies up to 18 to 24 months to complete.

Marcellus Shale Coalition and CenterPoint Energy, Inc. suggested PHMSA provide a later effective date to provide the regulated community with enough time to comply with the regulations. Other commenters agreed with this sentiment and suggested PHMSA provide various effective dates for the rule, from 12 months after the publication date of the final rule up to 3 years following the publication of the final rule, with several commenters recommending 3 years to be consistent with the then-proposed EPA's rulemaking described in section II.E.

Atmos Energy Corporation; Fort Valley Utility Commission; Alexander City Gas Department; City of Sylvania, GA; City of West Point; CenterPoint Energy, Inc.; Philadelphia Gas Works; Municipal Gas Authority of Georgia; City of Cartersville Gas System; NiSource Inc.; City of Adairsville; and Great Basin Gas Transmission Company said there should be differing effective dates for different portions of the rule based on the complexity and scope of changes in different portions of the rule as well as the time and resources needed for compliance.

Northeast Gas Association and National Grid recommended PHMSA provide a phased-in approach over the span of 3 years. The commenters stated that if a 3-year phase-in approach is not acceptable, then PHMSA should consider a stay of enforcement for 3 years following the effective date to allow operators adequate time to implement changes in compliance with the rule. According to the commenters, if PHMSA provided a stay of enforcement, operators would agree to develop and implement a workplan for compliance within 90 days of the publication of the final rule. Kinder Morgan, Inc. similarly expressed support for a 3-year phase-in approach and suggested PHMSA provide operators with 12 months to comply with most sections and 18 months to comply with the ALDP requirements if PHMSA did not provide an effective date of 3 years after the publication date of the final rule. Williams Companies, Inc. did not support a phased approach to the rule's requirements.

The Industry Trades; Northeast Gas Association; Southern Company Gas; American Gas Association, Energy Association of Pennsylvania, Florida Natural Gas Association, et al.; INGAA; Southwest Gas Corporation; and Great Basin Gas Transmission Company recommended PHMSA align the effective date of the rule with the start of the calendar year. Southern Company Gas and Philadelphia Gas Works said it would be necessary for the effective date of several of the subpart M proposals to occur on January 1st to match with the start of the calendar year to allow for a seamless transition. The commenters requested PHMSA provide an effective date for subpart M requirements of at least 30 to 60 months after the publication of the final rule.

In addition to comments on compliance timelines, PHMSA received extensive general comments on the rulemaking. Multiple public and environmental advocacy groups, several form letter campaigns, and a couple of individual commenters expressed general support for PHMSA's focus on public safety in the NPRM. The Associations strongly opposed PHMSA's determination that existing pipeline operator leak detection and repair practices are insufficient to meet risks to public safety from methane leaks.

The EDF stated the NPRM supports the Biden Administration's greenhouse gas pollution reduction initiatives. Multiple operators said PHMSA did not adequately consider the entirety of the U.S. Methane Action Plan[591] in determining the necessity and scope of the NPRM.

The North Dakota Petroleum Council expressed concern that PHMSA "miscalculated" several provisions of the NPRM and would not improve safety for the environment or the public. The New York State Department of Public Service wrote that the proposed changes would bring Federal regulation for leak detection and repair closer in alignment with New York's State pipeline practices and requirements and would significantly enhance public safety. The MD Attorney General et al. and Pennsylvania Senator Katie Muth supported the NPRM and warned that current pipeline safety and leak standards are dangerously out of date and need to be improved. Likewise, an individual commenter supported the NPRM because it would improve

[591] White House Office of Domestic Climate Policy, U.S. Methane Emissions Reduction Action Plan (Nov. 2021), https://www.whitehouse.gov/wp-content/uploads/2021/11/US-Methane-Emissions-Reduction-Action-Plan-1.pdf.

community and worker safety as well as raise expectations for operators' pipeline safety practices.

Energy Transfer LP requested PHMSA provide guidance to regulated parties on how to balance public safety concerns with the added focus on detecting and repairing methane leaks that do not pose a public safety risk. BlueGreen Alliance warned that leaks increase explosion risk from the ignition of volatile gases from gathering, transmission, and distribution lines and present an immediate threat to worker safety and frontline communities.

A form letter campaign and American Lung Association, et al. expressed concern that methane emissions have been extremely detrimental to public health. Colorado Jewish Climate Action urged PHMSA to consider preparing a quantification of health benefits and include it in the RIA for the final rule.

The PST stated that the rule would have a positive impact on environmental justice communities. Form letter campaigns, public advocacy groups, several individual commenters, and the EDF stated that low-income areas and people of color are more likely to be adversely affected by proximity to pipelines, putting them at higher risk for personal health issues and environmental disaster. Multiple public advocacy groups recommended that PHMSA work to protect vulnerable populations and expand its environmental justice discussion in the final rule.

The MD Attorney General et al. asserted that the current requirements for pipeline operation are insufficient and could adversely contribute to environmental justice concerns, citing several studies to state that there are consistently higher densities of unrepaired leaks near the homes of people of color, lower income persons, renters, adults with lower levels of education, and limited-English-speaking households.

Senator Cruz, et al. remarked it would be unnecessary for the NPRM to directly address environmental justice concerns if the rule's primary purpose is to improve gas pipeline safety and protect the environment by reducing leaks from pipelines. Chesapeake Utilities Corporation wrote that, while PHMSA's environmental justice goals are laudable, increasing the cost of energy consumption and production through additional regulation would negatively impact these goals at the same time.

Several individual commenters, the Associations, and multiple operators expressed general support for PHMSA's goal to reduce methane emissions. Similarly, Project Canary, PBC supported PHMSA's goal of expanding its best management practices for reducing harmful emissions and for its approach to promoting operational stewardship. Multiple operators expressed concern that the NPRM prioritizes climate change mitigation more than safety.

An individual commenter supported PHMSA's focus on curbing methane emissions, reasoning that this would have a greater impact at reducing climate change than targeting carbon dioxide alone. Additionally, a form letter campaign and PennEnvironment asked PHMSA to finalize the strongest possible pipeline safeguards to cut methane emissions and other harmful forms of pollution. A form letter campaign stated that it was crucial to address methane leakage throughout the entire natural gas supply chain, including production, processing, storage, and transportation.

The California State Teachers Retirement System reported that, across the entire industry, emissions from pipeline infrastructure are significantly underestimated, complicating investors' assessments of company-specific performance and methane-related risks. Northeast Gas Association cited EPA's Inventory of Greenhouse Gas Emissions and Sinks to report that methane emissions from natural gas distribution systems have declined 70 percent from 1990 to 2021. The Associations remarked that the pipeline industry continues to demonstrate its seriousness to address methane leaks and remediation. Rep. Rick Larsen, et al. stated that the NPRM would help reduce annual methane emissions by as much as one million metric tons, equivalent to 25 million metric tons of carbon dioxide.

A couple of form letter campaigns and the PST said that by limiting future methane emissions, the NPRM would address some of the most immediate effects of climate change, including extreme weather events and natural disasters. Rep. Rick Larsen, et al. and Miller/Howard Investments, Inc. stated that the rulemaking would continue to improve pipeline safety while reducing harmful methane emissions that contribute to near-term climate warming. The Colorado Public Utilities Commission, 350 Colorado, Aclima, Inc., and an individual commenter supported PHMSA's goal to address climate change. Likewise, the MD Attorney General et al. wrote that the rule would substantially improve the safety of existing pipelines and related gas infrastructure while significantly reducing their contribution to climate change through leaks. Climate Code Blue wrote that methane is a potent GHG but relatively short lived in the atmosphere, such that the NPRM would have rapid effects on ameliorating climate change.

Conversely, North Dakota Petroleum Council wrote that the NPRM would apply burdensome and duplicative requirements to achieve no additional benefits towards addressing climate change and safety. Senator Cruz, et al. also expressed opposition to PHMSA's goal to address climate change and stated that Congress did not direct PHMSA to address environmental justice or climate concerns. An individual commenter opposed the NPRM and stated that environmental considerations of greenhouse gases are not the purview of PHMSA.

An individual commenter and multiple environmental representatives supported the NPRM, stating it would reduce environmental hazards by increasing the identification of leaks that operators often miss. The Colorado Public Utilities Commission likewise expressed support for PHMSA including environmental harm among the hazards addressed by the rule. The New York State Department of Public Service stated that many of the proposed provisions would significantly lessen pipeline operations' impact on the environment.

A couple of form letter campaigns wrote that safeguarding communities, protecting the environment, and promoting responsible energy practices should be top priorities in infrastructure and pipeline development. The Pennsylvania Environmental Council stated that the NPRM would improve accountability and transparency by taking significant actions to mitigate operational gas releases while expanding the applicability of minimum safety standards to additional miles of gathering pipelines.

The PST urged PHMSA to consider requiring operators retire (i.e., abandon) pipelines that are "dangerous;" "located in areas that make leak surveys, detection, and repair difficult;" or that are "no longer economically feasible."

3. GPAC Deliberation Summary

The GPAC discussed the NPRM's proposed compliance deadlines beginning on March 26, 2024, where PHMSA staff presented a short briefing on the publication date, effective date, and compliance date; the proposed effective date and compliance dates from the NPRM; and a summary of the public comments. Following this, the GPAC provided opportunities for members of the public present at the meeting to present their feedback. Among the handful of stakeholders taking this occasion to provide feedback related to compliance timelines were numerous distribution and transmission operators, a compliance consultant, and a public interest environmental lawyer. Stakeholders similarly addressed concerns with compliance timelines for other requirements, such as ALDP and procedure manual requirements during those portions of the meeting. Multiple commenters referenced their written comments and emphasized that the proposed six-month compliance and effective date was not a sufficient amount of time to adequately implement the changes imposed by such a large and complex rule. Commenters from industry cited vendor availability for leak detection equipment; changes in equipment, reporting, policies and procedures, and work management systems; as well as the challenges of modifying and expanding training for the workforce. The majority of public commenters, which represented industry, supported a 3-year effective date or compliance deadline. Multiple commenters supported a compliance date of January 1st because of the calendar-based nature of these compliance activities. The public interest lawyer supported a swift compliance date of 6 months so that the environmental and safety benefits are not further delayed; however, should that not be possible, the commenter requested a compliance date that would be as soon as practicable and shorter than the 3-year deadline proposed by industry stakeholders. This commenter instead proposed to target extensions beyond 6 months for particular industry segments for particular regulatory requirements, which could not be feasibly completed within 6 months.

GPAC members then discussed the proposed compliance dates at length over the course of March 26 and 27, 2024. GPAC members representing industry echoed the sentiments shared by many public commenters stating that the changes associated with this rulemaking will take time to implement due to the size of this rule. These members shared concerns about under-resourced smaller operators struggling to adopt the new requirements on a fast timeline due to the potentially limited availability of leak detection vendors and skilled workers. There was broad support among members for a January 1 compliance date for administrative ease. One member supported aligning the timeline with EPA's then-ongoing 40 CFR 60 subparts OOOOa though OOOOc rulemakings, these rules are described in section II.E. Members representing industry raised concerns of some leaks being managed under the old regulatory regime and beginning to grade and schedule leaks under a new regulatory regime. Following debate multiple GPAC members representing industry raised that it would be reasonable for operators to have their program in place within 18 months so that operators are demonstrating the ability to comply with the new regulations. Some GPAC members representing state pipeline safety agencies expressed a desire for speedy implementation. Other members of the GPAC (including those representing the public), meanwhile, expressed the urgent need to ensure community safety and to mitigate methane emissions from an environmental perspective, and therefore supported a deadline of less than 3 years. As a compromise, there was openness to having phased deadlines, with earlier compliance timelines for certain program development and reporting requirements. As the conversation developed, GPAC members representing all stakeholders (industry, government, and the public) came to agree that large-volume gas release reporting merited an "accelerated" timeline, as operators already have the capability to measure the volume of gas loss for incident reporting. A GPAC member representing government shared that it was not the role of the Committee to dictate an effective date and that should be ultimately left for the agency. Some of those GPAC members representing the public consequently suggested interim reporting and information sharing so that public stakeholders can see how operators are strengthening their programs and are complying with the new rule.

4. GPAC Recommendation

The GPAC's recommendations on compliance deadlines reflect a unanimous consensus among Committee members regarding how PHMSA could adjust its proposal to navigate the different considerations described above. The Committee stated that the NPRM, as published in the Federal Register and supported by the PRIA and DEA, was technically feasible, reasonable, cost-effective, and practicable with regards to the effective and compliance dates if the following changes were made:

- Require operators develop the written leak detection program within 18 months of the effective date and begin compliance with the program on the general compliance date (§ 192.763).
- Implement a general compliance date of 36 months from the publication date of the final rule, with compliance dates beginning on the nearest January 1.

- Consider reporting large-volume gas releases that are intentional within 24 months of the effective date (§ 191.19).
- Address the issues and concerns raised by members during the course of the GPAC meeting to address those leaks existing before the compliance date of the final rule (§ 192.760).

While much of the GPAC discussion had focused on recommending a single compliance date for the full rule, the GPAC's recommendations ultimately settled on a phased approach of the requirements to ensure that operators are making progress before the full compliance date. Committee discussion coalesced around an effective date of 6 months, which will inform the compliance dates; however, the Committee ultimately did not make a specific recommendation for an effective date. The Committee's recommendations reflect a desire to figure out how to address existing legacy leaks as well as how to apply a compliance date and implementation schedule that ensures that operators both small and large have sufficient time to develop and implement a multitude of programs, processes, and systems; hire and train human capital; and procure proper technologies. The Committee ultimately left the decision of how to incorporate existing leaks into the new regulations up to PHMSA.

5. PHMSA Response

PHMSA appreciates the comments and concerns received regarding the effective and general compliance dates for this rule. As discussed in the paragraph above, the Committee discussed the appropriateness of the proposed effective date of 6 months after the publication of the final rule and corresponding general compliance date. PHMSA acknowledges and understands the concerns raised by public commenters and the recommendations made by the Committee. In response, for this final rule, PHMSA has adopted the GPAC recommendation to implement a general compliance date for most amendments corresponding with the start of the calendar year and following 36 months after the publication of the final rule, specifically January 1, 2028.[592] This compliance timeline was recommended by the GPAC and supported in public comments, and it is designed to provide a practicable timeline for regulated entities to develop programs, revise procedures, acquire leak detection equipment if necessary, and train operator personnel to use new equipment and follow any new procedures. As noted in section III.P, this compliance deadline also applies to most requirements applicable to regulated gas gathering lines. As demonstrated in the RIA, delaying implementation of the requirements in the final rule results in reduced costs and benefits due to additional discounting of economic impacts that occur in the future; however, this change is necessary in order to ensure that the amendments in the final rule can be practicably and effectively implemented.

To aid regulated entities in their understanding of the adopted compliance dates, PHMSA has added § 192.703(f) to the final rule defining the compliance timelines for the amendments to subpart M, which provides an easy-to-use tabular depiction of the compliance timelines titled "Table 1 to § 192.703." Prior to the compliance date contained within the table, regulated entities must comply with either the existing requirements of subpart M or with the amended requirements of subpart M from the final rule. After the compliance date contained within the table, regulated entities must comply with the amended requirements of subpart M from the final

[592] A few exceptions apply; see discussions throughout this final rule on §§ 192.703(d), 192.760, and 192.763.

rule. For §§ 192.703(c), 192.705, 192.706, 192.723, 192.739(c) and (d), and 192.770, the compliance date adopted in this final rule is January 1, 2028. For § 192.703(d), the compliance date is the effective date of the final rule.

PHMSA appreciates the public comments and the Committee discussion regarding the effective and compliance dates for leak detection programs as prescribed at § 192.763. PHMSA acknowledges the Committee recommendation to require the development of the written leak detection program within 18 months of the effective date and begin compliance with the program on the general compliance date. In this final rule, PHMSA has adopted a compliance date of 18 months after the publication date of the final rule for operators to develop the written leak detection program required by § 192.763, and a compliance date of January 1, 2028, to implement and comply with that written program. This revision allows PHMSA to evaluate operator progress during the implementation timeframe of this final rule. Additionally, since other compliance actions, such as qualifying operator personnel, are contingent on having programs and procedures in place, an earlier compliance timeline for such requirements avoids delay in the implementation of this final rule. Finally, PHMSA is clarifying in this final rule that operators are not required to begin complying with the completed leak detection program until the January 1, 2028, compliance date, which addresses a concern raised during the GPAC discussion of an expedited compliance date for plan development. As described in section III.P, PHMSA has applied a similar timeline to the procedure manual requirements for Type B and Type C gathering lines.

PHMSA appreciates the comments and concerns received regarding the effective and compliance dates for repairs of pre-existing leaks as prescribed at § 192.760. The Committee also discussed the appropriateness of the specific compliance dates prescribed in the NPRM for pre-existing leaks. In this final rule, PHMSA has adopted the GPAC recommendations on this subject at § 192.760(a)(3); see section III.I for more details on the compliance timelines for pre-existing leaks. In general, the revisions PHMSA made to the compliance timelines for pre-existing leaks in this rulemaking eliminates the upfront compliance costs for operators to re-grade existing leaks without undermining existing State and operator initiatives.

PHMSA acknowledges the public comments and Committee discussion regarding the reporting of large-volume releases; PHMSA's response to the GPAC recommendation on this subject is discussed in section III.L.

In addition to these specific comments and concerns on the effective and compliance dates of the final rule, PHMSA acknowledges the numerous general comments received in support of, and in opposition to, the proposals contained in the NPRM and the intent of the NPRM. PHMSA has considered these comments throughout the development of this final rule. PHMSA mission is to protect the public and the environment by ensuring the safe transportation of energy and other hazardous materials by pipeline. This final rule achieves PHMSA's mission by reducing methane emissions from new and existing gas transmission pipelines, distribution pipelines, regulated gas gathering pipelines, UNGS facilities, and LNG facilities.

PHMSA disagrees with comments suggesting that PHMSA's consideration of benefits to the public from protecting the environment, including benefits from reducing GHG emission, is inappropriate or unlawful. PHMSA's consideration of environmental benefits is both appropriate and explicitly required by law.[593] PHMSA's consideration of quantified benefits associated with reducing GHG emissions associated with releases of natural gas is consistent with accepted guidance for preparing cost-benefit analysis in OMB Circular A-4[594] and is not prohibited by law or regulation. Similarly, Federal agencies are directed to consider environmental justice under the National Environmental Policy Act, E.O. 12898, and E.O. 14096; however, the substantial quantified net benefits described in the final RIA for this rulemaking demonstrating that benefits of this final rule justify its costs do not include any quantified environmental justice benefits. Finally, while the primary quantified benefits of this final rule are associated with reducing releases of natural gas into the atmosphere, key portions of this final rule directly address pipeline safety issues. Notably, the vast majority of leak grading criteria in § 192.760 addresses the likelihood of harm to public safety from the risk of fire and explosion, and changes to the leakage frequency for gas transmission lines target areas with higher public safety risk.

Regarding the request for PHMSA to provide additional guidance on balancing public safety and environmental considerations, changes to the leak grade definitions described in section III.H address a number of sources of uncertainty described in other public comments. Specifically, this final rule eliminates the descriptive language introducing each grade, confirming PHMSA's intent that the grades are defined by the listed criteria. Additionally, this

[593] See for example 49 U.S.C. 60102(b)(1)(B)(ii), (b)(2)(A)(iii), (b)(5), (q)(1)(B), and (q)(B)(i).
[594] Office of Management and Budget. Circular No. A-4. (November 9, 2023). https://www.whitehouse.gov/wp-content/uploads/2023/11/CircularA-4.pdf. Pg. 8 and footnote 12.

rulemaking has finalized quantifiable standards for leaks meriting repair or prioritization due to their release rate. This is described in detail in section III.H.

Regarding comments from PST regarding pipeline abandonment, various requirements, including § 192.760 in this final rule require the remediation of potentially unsafe conditions. Additionally, existing § 192.703(b) requires the replacement, repair, or removal from service of any pipeline segment that has become unsafe. Business decisions regarding the operation of pipelines that are not economically viable is beyond the scope of this rule.

IV. Section-by-Section Analysis

§ 191.3. Definitions.

Section 191.3 provides definitions for various terms used throughout 49 CFR part 191 and PHMSA Forms referenced in that part. PHMSA is amending the proposed definition of "*large-volume gas release"* that must be reported, as detailed in the newly added § 191.19. A large-volume gas release is any intentional or unintentional release of gas of 500,000 cubic feet or more released within a 96-hour period. This new large-volume gas release reporting requirement will be applicable to all gas pipeline facility operators, including (but not limited to) operators of jurisdictional underground storage and LNG facilities, as well as Type R gas gathering pipelines.

PHMSA is also revising the property damage criterion within the definition of "*incident*" to exclude certain indirect costs associated with the cost incurred by operators in conducting repair activity. In particular, the revised definition excludes the cost of preparing and obtaining permits, as well as the removal and replacement of third-party infrastructure that was not itself damaged by the event. For example, if a release from a pipeline beneath a street did not damage a roadway, but pavement must be temporarily removed to repair the pipeline, the costs of the roadway repair and associated permits will not be included in the definition of property damage.

§ 191.11 Distribution system: Annual report.

PHMSA is revising Form F 7100.1-1 and its instructions to collect data on leaks detected and repaired by grade in the annual reporting period and the number (by grade) of unrepaired leaks at the conclusion of the annual reporting period. PHMSA will also be receiving the number of Grade 2 and 3 leaks that have deferred timelines for repair or eliminations. PHMSA is also revising miscellaneous sections of those annual reports and their instructions to remove statements expressing or suggesting that releases that can be eliminated by routine maintenance (such as lubrication, tightening, or adjustment) need not be reported as leaks. Such leaks and leak repairs would instead be reported based on the requirements in the revised regulations.

§ 191.17 Transmission systems; Gathering systems; Liquefied natural gas facilities; and Underground natural gas storage facilities; Annual report.

PHMSA is revising the gas transmission and regulated gathering annual report form (Form F 7100.2-1) and its instructions to collect data on leaks detected and repaired by grade during the annual reporting period. This form change is applicable to gas transmission, offshore gas gathering, and Type A, B, and C regulated onshore gas gathering pipelines. PHMSA is not revising the Type R annual report form (Form F 7100.2-3), Liquid Natural Gas (Form F 7100.3-1), and Underground Natural Gas Storage Facility (Form F 7100.4-1). Lastly, PHMSA is revising miscellaneous sections of the annual report (and accompanying instructions) for each of gas transmission, offshore gathering, and regulated onshore gathering pipelines (Form F 7100.2-1), to remove statements expressing or suggesting that releases that can be eliminated by routine maintenance (such as lubrication, tightening, or adjustment) need not be reported as leaks. A count of leaks eliminated by routine maintenance would instead be reported in accordance with the revised regulations.

§ 191.19 Large-volume gas release reports.

PHMSA is adding a new § 191.19 requiring operators to submit quarterly reports of large-volume gas releases (Form F 7100.5). Like incident reports, this requirement will be applicable to all operators of PHMSA-jurisdictional gas pipeline facilities, including operators of jurisdictional underground storage and LNG facilities, as well as Type R gas gathering pipelines. This report will be required for intentional gas releases that become reportable on or after the date 36-months from the effective date of this final rule. A report of a large-volume gas release for unintentional gas releases must be included if the release becomes reportable on or after January 1, 2028.

The new report will require pertinent operators to report both intentional and unintentional releases of gas that meet the definition of a "*large-volume gas release*" as defined at amended § 191.3. This new form will capture both unintentional, fugitive emissions (e.g., from leaks) as well as blowdowns, maintenance related venting, releases from pressure relief devices operating as intended, and other intentional, vented emissions. Operators will be required to submit the form on a quarterly basis with deadlines of April 30, July 31, October 31, or January 31 of each year, containing the releases that occurred in the previous quarter.

Events reported as incidents under §§ 191.9 or 191.15 will not be required to be reported under the new§ 191.19. However, if an unintentional release reported as a large-volume gas release 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.

§ 192.3 Definitions.

Section 192.3 defines various terms used throughout part 192. PHMSA is adopting several definitions that will be used in the new § 192.760,

PHMSA is amending the proposed definition of a "*confined space*" as any space where gas can accumulate or migrate, of sufficient size and configured so a person can enter, has limited or restricted means to enter or exit, and is not designed for continuous occupancy. These would include vaults, catch basins, and manholes. Unlike a building, a confined space is not ordinarily occupied for residential, commercial, or industrial uses. The difference between a confined space and a substructure is that a confined space is large enough to accommodate a person, while a substructure is not. A confined space is also no longer limited to subsurface structures compared with the proposed definition. This revised definition is consistent with the definition of a "confined space" used by OSHA at 29 CFR 1910.146(b), though it is not limited to facilities accessible by the operator's employees.

PHMSA is also amending the proposed definition of a "*gas-associated substructure"* as a substructure that is part of an operator's pipeline facility but is not itself designed to convey or store gas. These typically consist of small vaults for devices, such as valves, meters, regulators, or other equipment.

PHMSA is also adopting a definition of "*lower explosive limit (LEL)*" as that term will be used in parts 192 and 193. Specifically, the LEL is 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. The LEL of natural gas is 5 percent methane in air by volume. The LEL for propane is 2.1 percent propane in air by volume. The LEL for hydrogen gas is 4 percent hydrogen by volume.

PHMSA is also adopting a definition of a "*substructure*" as any subsurface structure that is not large enough for a person to enter and in which gas could accumulate or migrate. Substructures include telephone and electrical service boxes and associated ducts and conduits, valve boxes, and meter boxes.

PHMSA is also adopting a definition of "*tunnel*" as a subsurface passageway large enough for a person to enter and in which gas could accumulate or migrate. Compared with a confined space, a tunnel is a "passageway" intended for regular or occasional human occupancy, essentially an underground "building" designed for regular travel.

PHMSA is also adopting a definition of *"wall-to-wall paved area*" as an area where the ground surface between the curb of a paved street and the front wall of a building is continuously paved with hard top surface impermeable to gas, excluding non-continuous landscaping such as tree plots.

§ 192.9 What requirements apply to gathering lines?

Section 192.9 specifies requirements for gathering lines. This final rule amends requirements at § 192.9 for all part 192-regulated onshore and offshore gathering lines, including Types A, B, and C gathering pipelines.

Requirements for Type A gathering pipelines are defined at § 192.9(c), which requires that a Type A pipeline comply with the requirements of part 192 for transmission lines, subject to specific exceptions listed in that paragraph. PHMSA has made no amendments to § 192.9(c). Therefore, all revisions, adoptions, and changes applicable to transmission lines in this final rule apply to all Type A gathering pipelines, including each of the following: revised definitions; design and configuration of pressure relief devices (§ 192.199); modification of procedural manuals to provide for eliminating leaks in accordance with § 192.760 and minimization of releases of gas as well as the remediation or replacement of pipelines known to leak (§ 192.605); revision of failure investigation procedures to add a definition of the term failure (§ 192.617); enhanced patrolling requirements (§ 192.705); enhanced leakage survey requirements (§ 192.706); new leak grading, repair, and documentation requirements (§§ 192.703(c) through (f), 192.760, and 192.763); new pressure relief device maintenance requirements (§ 192.739); and specific requirements for minimization of blowdown emissions (§ 192.770).

Part 192 requirements applicable to Type B gathering pipelines are contained at § 192.9(d). In this final rule, PHMSA has amended § 192.9(d) to require each newly installed, replaced, or relocated Type B gathering line comply with a new § 192.199 for the design and configuration of pressure relief devices. PHMSA is also amending § 192.9(d) to add a number of requirements for enhancing leak detection, grading and repair programs, including the following: revised definitions; introduction of procedural manuals providing for, among other things, the elimination of leaks and minimization releases of gas as well as remediation or replacement of pipelines known to leak (§§ 192.9(d)(4) and 192.605); annual patrolling requirements (§ 192.705); enhanced leakage survey requirements (§ 192.706); new pressure relief device maintenance requirements (§ 192.739(c)(d)); and new leak grading, repair, and documentation requirements (§§ 192.703(c)-(f), 192.760, and 192.763). The final rule requires operators of Type B gathering lines to prepare, update and follow a manual of written procedures for carrying out the part 191 and part 192 requirements listed at § 192.9 applicable to that facility. Additionally, the operator must have procedures to address the self-executing mandates at section 114 of the PIPES Act of 2020 to eliminate leaks, minimize releases of natural gas, and remediate or replace pipelines known to leak (§ 192.605(b)(13)); gather information needed to report incidents under part 191 (§ 192.605(b)(4)); and instruct personnel to recognize SRCs (§ 192.605(d)). The procedures required for Type B gathering lines in this final rule must be prepared, reviewed, updated, and made available in accordance with the requirements at § 192.605(a). This final rule also requires operators of Type B gathering pipelines to establish and implement the emergency planning requirements at § 192.615. Similar to Type C gathering lines previously, operators of Type B gathering lines will be required to comply with the requirements in § 192.615 as those requirements appeared on October 4, 2022.[595] While the

[595] Refer to the final rule titled "Pipeline Safety: Requirement of Valve Installation and Minimum Rupture Detection Standards: Technical Corrections" published on August 1, 2023 (88 FR 50056)

procedure manual requirements described above do not cross reference § 192.605(e), since § 192.615 is applicable to Type B gathering lines in the final rule, operators of Type B lines must have procedures required under that section.

PHMSA amends § 192.9(e) to expand the list of part 192 operations (subpart L) and maintenance (subpart M) requirements applicable to all Type C gathering pipelines to include: revised definitions; procedural manuals for carrying out the part 191 and part 192 requirements applicable to the facility and the section 114 mandate from the PIPES Act of 2020 (§§ 192.9(e)(1)(iii) and 192.605); annual patrolling requirements (§ 192.705); leakage survey requirements (§ 192.706); pressure relief device maintenance requirements (§ 192.739(c) and (d)); and new leak grading, repair, and documentation requirements (§§ 192.703(c)-(f), 192.760, and 192.763). This final rule requires that newly installed, replaced, or relocated Type C gathering lines comply with the pressure relief device design and configuration requirements at § 192.199.

The final rule requires operators of Type C gathering lines to prepare, update and follow a manual of written procedures for carrying out the part 192 requirements listed at § 192.9 applicable to that facility. Additionally, the operator must have procedures to address the self-executing requirements at section 114 of the PIPES Act of 2020 (§ 192.605(b)(13)); gather information needed to report incidents under part 191 (§ 192.605(b)(4)); and instruct personnel to recognize SRCs (§ 192.605(d), unless the facility is excepted from reporting SRCs in accordance with § 191.23(b)(1). The procedures required for Type C gathering lines in this final rule must be prepared, reviewed, updated, and made available in accordance with the requirements at § 192.605(a). While the procedure manual requirements described above do not cross reference § 192.605(e), since § 192.615 is applicable to Type C gathering lines, operators of Type C lines must have procedures required under that section.

§ 192.12 Underground natural gas storage facilities.

Section 192.12(c) contains requirements for operators of underground natural gas storage facilities to have and follow written procedures for operations, maintenance, and emergency response activities. PHMSA is revising this provision to incorporate within its regulations the self-executing mandate in section 114 of the PIPES Act of 2020 that requires operators to update their procedures to provide for the elimination of leaks that represent an existing or probable hazard to public safety, property, or the environment, and the minimization of releases of natural gas from pipeline facilities.

§ 192.18 How to notify PHMSA.

Section 192.18 describes how an operator must provide notification. PHMSA is amending paragraph (c) of this section with conforming changes in support of the final rule. Specifically, the final rule allows operators to use alternative compliance approaches with advance notification to PHMSA in connection with the following requirements: alternative methods for estimating release rate (§ 192.760(c)(1)(C) and (d)(2)(ii)(C)); and implementation of an alternative ALDP performance standard (§ 192.763(d)).

Each of these flexibilities is described separately under its respective discussion in this section IV. As specified in existing § 192.18(c), an operator must notify PHMSA 90 days in advance of using an alternative compliance approach and may begin to use that alternative approach if they do not receive a letter after 90 days objecting to that alternative compliance approach from PHMSA.

Section 192.770(c)(5) requires an operator to notify PHMSA when performing a covered blowdown without mitigation in accordance with that section due to substantial negative impact to customers' health or safety due to a prolonged loss of gas supply; however, notifications tied to that exception do not invoke the no-objection procedure in § 192.18(c).

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

Section 192.199 provides requirements for the design of pressure relief and limiting devices. PHMSA is amending the proposed revisions to § 192.199 to address the design and configuration of relief devices. Any new, replaced, or relocated overpressure protection device and associated piping must be designed and configured to minimize releases of gas to the atmosphere. Section 192.199 is a generally applicable design requirement and applies to all part 192-regulated facilities, including gas transmission, distribution, offshore gas gathering, and Types A, B, and C onshore gas gathering pipelines. This requirement will not be retroactive and does not apply to any device and its associated piping on pipelines existing on or before January 1, 2028, unless the device is subsequently replaced or relocated.

To comply with this requirement, each pressure relief device must be designed and configured so that the set and reseat pressures of the device, including where pressures are measured, minimize releases of gas beyond what is necessary to provide overpressure protection. Additionally, the design and configuration of the relief device and its associated piping must be appropriate for providing adequate overpressure protection. Additionally, the design and materials used for the relief device must be compatible with the composition of the gas being transported and be suitable for the anticipated operating and environmental conditions. The design piping of the relief device must include isolation valves to support testing and maintenance.

PHMSA is also amending § 192.199(f) to incorporate the requirements in proposed § 192.199(i)(2). Specifically, in addition to the existing requirements to ensure that relief devices and associated piping are designed to prevent hammering of the valve and impairment of relief capacity, the final rule clarifies that the design must prevent damage to the valve, interconnected piping, or related components. Service regulators with an internal relief or passive pressure relief or limiting devices that do not release gas to the atmosphere on distribution systems are not subject to § 192.199(i)(4).

§ 192.605 Procedural manual for operations, maintenance, and emergencies.

Section 192.605 requires each operator of an onshore or offshore gas transmission pipeline, gas distribution pipeline, offshore gas gathering pipeline, or Type A gas gathering pipeline to prepare and follow a written procedure manual for operations, maintenance, and emergency response activities. PHMSA revises § 192.605 to incorporate the self-executing mandate at section 114 of the PIPES Act of 2020. PHMSA revises § 192.605(b)(13) to specify that the O&M procedures for part 192-regulated gas pipelines must include procedures for eliminating leaks in accordance with leak repair schedules (specified at § 192.760) and minimizing releases of gas from pipelines, as well as remediating or replacing pipelines known to leak based on their material, design, or past maintenance and operating history.

Section 192.9 requires Type B and Type C gathering lines to have and carry out a manual of written procedures for complying with the part 191 and part 192 requirements applicable to the pipeline facility. Refer to the section-by-section analysis of § 192.9 for additional information on procedure manual requirements applicable to Type B and Type C gathering lines.

§ 192.617 Investigation of failures.

Section 192.617 provides requirements for operators on the investigation of failures and incidents. PHMSA is amending § 192.617 to include a definition of the term "failure" for the purposes of § 192.617, as "an event in which any portion of a pipeline becomes completely inoperable, 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." This definition mirrors the definition in ASME B31.8S. As indicated above, this regulatory amendment would apply to gas distribution, gas transmission, offshore gas gathering, and Type A regulated onshore gas gathering pipelines.

§ 192.703 General.

Section 192.703 is a general provision that requires maintenance of pipeline segments in accordance with subpart M, prompt response to unsafe pipelines, and timely repair of hazardous leaks commensurate with the seriousness of the leak. PHMSA revises this section to remove the historical reference to "hazardous leaks" in paragraph (c) of that section and require compliance with the leak grading and repair requirements at the new § 192.760. This final rule will require all part 192-regulated gas pipelines to comply with the revised § 192.760 general leak grading and repair requirement.

PHMSA also adds new paragraph (d) to § 192.703 excepting from the general requirement that all part 192-regulated pipelines be subject to the leak detection and repair requirements of this final rule, gas transmission and gas gathering compressor stations subject to EPA methane emissions monitoring and repair requirements or subject to emissions monitoring requirements under an approved State or Tribal plan or Federal plan under the emissions guidelines for existing sources. Specific requirements from which eligible stations will be excepted include the following: leak repair (§ 192.703(c)), patrols and leakage surveys (§§ 192.705 and 192.706), leak grading and repair (§ 192.760(a) through (i) and (j)(1)), and ALDPs (§ 192.763). Repair recordkeeping requirements are not covered by this exception. Repair records must be maintained in accordance with § 192.760(j)(2).

Paragraph (d)(1) specifies that in order to be eligible for exception, the facility must be subject to methane fugitive emissions monitoring requirements within 40 CFR 60.5397a, 40 CFR 60.5397b, or requirements in an EPA-approved State or Tribal plan, or Federal plan plans that are at least as stringent as EPA's emission guidelines model rule provisions in 40 C.F.R. 60.5397c.This includes emissions monitoring using alternative means approved by the EPA under 40 CFR 60.5398a, 60.5399a, or 60.5399b and emissions monitoring using an approved alternative means according to 40 CFR 60.5398c.

As specified in § 192.703(d)(2), the portion of the facility subject to the exception consists of those facilities downstream of the inlet of the last block valve entering the station and upstream of the outlet of the first block valve exiting the station covered by the emergency shutdown system as required in accordance with § 192.167. Since the criteria in both paragraphs (d)(1) and (d)(2) must be met to be eligible for exception, the exception covers the identified block valves themselves if and only if those valves meet are themselves subject to EPA emissions monitoring as described above. Similarly, no facility downstream of the last fugitive emissions component subject to EPA emissions monitoring is excepted from part 192 leak detection and repair requirements. If an emergency shutdown system is not present, then the excepted portion of the facility is the portion of the facility covered by station overpressure protection between those same valves.

PHMSA also adds new paragraph (e) to § 192.703 exempting pipelines transporting gas containing more than 50 percent of hydrogen, by volume, from the requirements of § 192.760; however, this paragraph clarifies that such pipelines are required to promptly repair any leak that represents an existing or probable hazard to person or property, consistent with previous repair requirements at § 192.703(c) as that section existed on **[insert date of publication of the final rule]**.

Compliance deadlines for the leak detection and repair requirements in subpart M are addressed at the new § 192.703(f). In general, prior to the compliance deadline for each section listed in the new Table 1 of the revised § 192.703, an operator must comply with either the current requirements existing as of **[insert date of publication of the final rule]**, or the amended requirements of subpart M from the final rule published on **[publication date of this final rule]**.

After the compliance deadlines listed in the new Table 1, operators must comply with the amended requirements of subpart M.

§ 192.705 Transmission lines: Patrolling.

Section 192.705 requires visual right-of-way patrols on gas transmission lines at a prescribed frequency. PHMSA amends this section to increase the required frequency of right-of-way patrols on gas transmission pipelines to at least 6 times each calendar year for pipelines located in Class 3 and 4 locations, with intervals between patrols not exceeding 75 days and 4 times per calendar year for pipelines located in Class 1 and 2 locations, with intervals between patrols not exceeding 135 days.

§ 192.706 Transmission lines: Leakage surveys.

Section 192.706 requires operators to conduct leakage surveys on transmission lines at a prescribed frequency, with expedited frequencies on pipelines located in Class 3 and 4 locations and transporting gas without odorant in conformity with § 192.625.

PHMSA amends § 192.706 to require each leakage survey be performed using leak detection equipment and methods that meet the ALDP performance standard at the new § 192.763. The use of leak detection equipment is not required when performing leakage surveys on segments of onshore and offshore gas transmission pipelines that are submerged below the waterline of a body of water. Leak detection equipment must be used for leakage surveys of pipelines transporting gas containing 50 percent of more of hydrogen gas by volume, but the leak detection equipment does not need to comply with the advanced leak detection program requirements at § 192.763.

PHMSA has amended § 192.706 to require expedited leakage survey frequencies for: pipeline segments located in HCAs; pipelines segments known to leak based on material, design, or past operating maintenance history; and valves, flanges, tie-ins with valves and flanges, and in-line inspection launcher and receiver facilities. These leakage survey frequencies are further modified based on the class location within which the pipeline segment is located. For pipeline segments located in Class 1, Class 2, and Class 3 locations, leakage surveys must be conducted twice each calendar year, at intervals not to exceed 7 ½ months. Pipeline segments located in Class 4 locations must be surveyed more frequently at four times each calendar year, at intervals not to exceed 4 ½ months. PHMSA has not made changes to the survey frequency requirements for leakage surveys for pipelines located outside of HCAs, pipelines transporting gas without odorant in conformity with § 192.625, and pipelines located in the Alaskan North Slope; however, these facilities must still comply with ALDP requirements in § 192.763 and leak grading and repair requirements in § 192.760 as specified in paragraph (a) of this section.

§ 192.723 Distribution systems: Leakage surveys.

Section 192.723 requires that operators conduct periodic leakage surveys on gas distribution pipelines. The frequency of these surveys depends on the location of the pipeline and other local factors. PHMSA amends this section to incorporate the ALDP performance standard detailed at § 192.763 and to provide additional and expedited survey frequencies.

PHMSA has maintained the requirement for an interval for leakage surveys of at least once each calendar year, not to exceed 15 months, for distribution pipelines located within a business district.[596] Section 192.723 is amended to require this survey frequency on distribution pipelines outside of a business district, located outside of a building that meet any of the following:

1. Cathodically unprotected pipelines subject to § 192.465(e);
2. Pipelines known to leak based on their material (including, but not limited to, cast iron, unprotected steel, wrought iron, and historic plastics with known issues), design, or past operating and maintenance history; or
3. Any distribution pipeline protected by a distributed anode system, in the area of deficient readings identified during a cathodic protection survey pursuant to § 192.463 and appendix D until the cathodic protection deficiency is remediated.

The frequency of leakage surveys on gas distribution pipelines outside of business districts and located outside of a building remains at once every five calendar years, not to exceed 63 months.

PHMSA further amends § 192.723(d) to require leakage surveys of a distribution pipeline after an extreme weather event or natural disaster that could damage that pipeline segment through soil or pipe movement. This extreme weather event or natural disaster that occurs in the area of the pipeline can include, but is not limited to, a flood that exceeds high-water banks, a landslide, earthquake, a named tropical storm or hurricane, or where an operator has identified the potential for damage through their continuing surveillance program at § 192.613. This survey

[596] While the term business district remains undefined in part 192, there is an August 1972 interpretation letter that speaks to the issue. PHMSA refers all operators to refer to this letter for the time being.

must be initiated within 72 hours after the operator reasonably determines that the area can be safely accessed, and resources (personnel and equipment) are available.

§ 192.739 Pressure limiting and regulating stations: Inspection and testing

Section 192.739 prescribes the requirements for inspection and testing of pressure limiting and regulation stations. PHMSA incorporates proposed § 192.773 into § 192.739 by adding paragraphs (c) and (d), which require operators of gas distribution, transmission, offshore gathering, and Types A, B, and C gathering pipelines to prepare and follow written maintenance procedures for evaluating pressure relief devices that are found to have malfunctioned, provide for public safety, and remediate such malfunctions to minimize unnecessary releases of methane while providing adequate overpressure protection.[597]

PHMSA is amending the proposed actions at § 192.773 (now § 192.739(c) and (d)) that must be taken should a pressure relief device malfunction. In accordance with the new paragraph (c), a device malfunction is defined for this section as when a pressure relief device activates above its set pressure, activates above the pressure limits at §§ 192.201(a) or 192.739(b) as applicable, activates at a pressure below the set pressure, or otherwise fails to operate as designed or intended. Should this happen, the operator must take immediate action to stop the release of gas and restore overpressure protection. Alternative methods to provide for overpressure protection must be maintained in the interim until the device has been adjusted, repaired, or replaced. Operators must perform evaluations, tests, and inspections of the malfunctioned device to identify and remediate the cause of the malfunction and restore the

[597] The amendments to § 192.739 were proposed as a new § 192.773 in the NPRM.

pressure relief device. In a new paragraph (d), PHMSA is requiring operators to maintain records documenting pressure relief device malfunctions, and records pertaining to adjustment, repair, or replacement under this section, for the life of the device or the specific component.

§ 192.760 Leak grading and repair.

PHMSA creates a new § 192.760 to address requirements for grading and repairing leaks on gas distribution, transmission, offshore gathering, and Types A, B, and C gathering pipelines. As noted in the section-by-section analysis of § 192.703, this section does not apply to a pipeline transporting gas containing more than 50 percent of hydrogen gas by volume. Leaks on such pipelines that represents an existing or probable hazard to persons or property must be promptly repaired.

§ 192.760(a): General.

Paragraph (a) of this section requires operators to have and implement written procedures for leak grading and repair that meet or exceed the minimum requirements of this section. This section also addresses the requirements for managing leaks discovered before January 1, 2028.

This section applies to any leak detected by the operator and applies to all components of pipelines (including, but not limited to, pipeline pipe, valves, flanges, meters, regulators, tie-ins, launchers, and receivers). Each leak or indication of a leak must be investigated immediately, and a leak grade determination must be made as part of that investigation. An operator is not required to have completed pinpointing the source of a leak in accordance with § 192.763 in order to establish a grade, for example if gas is detected at the outside wall of a building, an operator can make a grade 1 determination prior to locating the source of the leak. However, if further investigation indicates conditions consistent with a higher grade exist, the leak must be upgraded in accordance with § 192.760(h). However, PHMSA expects operators to grade leaks thoroughly and accurately. If an operator commonly upgrade leaks in this manner it likely indicates inadequate initial investigation and grading procedures.

Paragraph (a)(3) addresses managing leaks discovered prior to January 1, 2028. For leaks discovered prior to January 1, 2028, operators must either comply with the requirements in § 192.760 or alternatively, grade, reevaluate, and repair existing leaks known to exist or discovered prior to the compliance date of this final rule in accordance with the operator's procedures and applicable Federal and State requirements existing on **[insert date of publication of the final rule]**, with a few additional stipulations. This includes the legacy Federal requirement to promptly repair hazardous leaks in § 192.703(c). For grade 2 leaks or leaks with an equivalent classification, operators must complete these repairs no later than 1 year after the compliance date of the rule (i.e., by January 1, 2029) or as specified in the operators' procedures and applicable state requirements existing on **[insert date of publication of final rule]**, whichever date is earlier. Equivalent intermediate grades include State-defined classification schemes such as Type 2, Type 2A, etc.

For all other leaks (i.e., leaks other than grade 1 and grade 2, or equivalents), the operator must reevaluate and repair the leak in accordance with their procedures. Any remaining leaks existing on January 1, 2028, must be reevaluated no later than January 1, 2029, and have a grade established in accordance with the new § 192.760 requirements. The leak must then be managed in accordance with the requirements in § 192.760 and repaired in accordance with the operator's procedures or with this final rule requirements in § 192.760, whichever date is earlier. For the purposes of establishing timelines for reevaluations and repairs, the date of discovery for these legacy leaks is the date that a grade was established under § 192.760(a)(3)(iii).

§ 192.760(b): Grade 1 leaks.

Grade 1 leak are the highest priority grade and represents an urgent or emergency situation. The final rule requires an operator take immediate and continuous action to promptly complete repair of a grade 1 leaks and eliminate and control hazardous conditions caused by the leak. PHMSA's paragraph (b)(2) includes a list of actions the operator may take to address the hazardous conditions pending repair. These steps include triggering actions under the operator's emergency plan under § 192.615, evacuating or blocking off the vicinity of the leak, rerouting traffic, eliminating ignition sources, ventilating the leak area to disperse flammable accumulations of gas, stopping the flow of gas in the facility, and/or notifying emergency responders. After a repair is attempted and prior to recheck, continuous action is no longer required as long as grade 1 leak conditions do not persist.

Paragraph (b)(1) provides minimum criteria for grade 1 leaks that need to be included in operators' leak grading procedures. Specific criteria include the following: any leak that—in the judgement of operating personnel (including determinations made in accordance with an operator's procedures)—requires immediate repair; any leak that has ignited; any indication of potential for ignition of accumulated gas resulting from gas migrating into a building, under a building, or into a tunnel; any indication of potential for ignition due to accumulated gas due to migration of gas to the outside wall of a building or to an area from which migration to the outside wall of a building could occur; gas concentration readings above 80 percent LEL (60 percent LEL for LPG) within either of a confined space or a substructure from which gas could migrate to the outside wall of a building; any leak that can be seen, heard, or felt that is in a location that may endanger the public or property; any leak on a transmission or regulated gas gathering line that has a calculated or measured leakage rate of 100 kg/hr or more; and any leak that is an incident pursuant to § 191.3.

§ 192.760(c): Grade 2 leaks.

In the final rule, grade 2 leaks represent an intermediate priority between grade 1 leaks and lower priority grade 3 leaks. PHMSA generally requires a grade 2 leak repair be completed as soon as practicable but within 12 months of discovery, but alternative timelines may apply as described below.

Paragraph (c)(1) of this section defines minimum criteria for defining a grade 2 leak. A leak meeting any of the grade 1 criteria may not be classified as a grade 2 leak. Among PHMSA's minimum criteria are leaks, other than grade 1 leaks, producing a gas reading of 40 percent LEL or greater under a sidewalk in a wall-to-wall paved area, or a reading of 100 percent or greater under a street in a wall-to-wall paved area with gas migration that is not a grade 1 leak. Similar to grade 1 criteria, the grade 2 criteria include criteria based on readings within confined spaces and substructures. A leak reading between 20 percent LEL and 80 percent of LEL in a confined space is a grade 2 leak. Unlike the grade 1 criteria, however, the grade 2 criteria make a distinction between gas readings in gas-associated and non-gas-associated substructures. A leak must be classified as grade 2 if it produces a reading less than 80 percent LEL in a non-gas-associated substructure from which gas could migrate. A leak with a reading of 80 percent LEL or greater in a gas-associated substructure from which gas could migrate to the outside wall of a building must be classified as a grade 2 leak. Like the grade 1 criteria, a grade 2 leak includes any leak that, in the judgment of operator personnel (or procedures), warrants repair within the grade 2 repair timeline of as soon as practicable not no later than 12 months from discovery.

In addition to those criteria, PHMSA has included criteria for identifying leaks as grade 2 leaks based on their flowrate. For distribution lines, paragraph (c)(1)(viii) defines a grade 2 leak on a distribution line to include any leak with a measured or calculated leakage rate that exceeds 10 SCFH, with a leak extent (area of land area affected by gas migration) is measured to be 2,000 square feet or larger. Simply put, the leak extent is the area of a rectangle drawn at the location of a buried leak that contains gas-affected soil within it. In order to measure the leak extent, an operator first establishes the perimeter of ground area affected by gas migration (i.e., with readings greater than zero percent gas) based on measurements taken at ground level. Then the operator locates zero percent gas readings outside of the leak perimeter, also taken at ground level. The leak extent area is the area of a rectangle parallel to the pipeline that contains the perimeter of the gas-affected surface. The length and width of the rectangle are established at points with zero percent gas readings. This is similar to the model method developed by HEET and certain operators in Massachusetts.[598]

[598] HEET. "Natural Gas Leaks of Significant Environmental Impact: Report of the 2018 SEI Field Trial." (March 2019). https://www.heet.org/gas-leaks/shared-action-plan-trial-year. Appendix 2 at pg. 22.

In addition to those two standard methods, a distribution operator may also use an alternative method determined to be equivalent to a leakage rate of 10 SCFH with notification to and no objection from PHMSA in accordance with § 192.18(a) through (c). An operator is only required to select one method per leak. For gas transmission or gathering lines, the volume-based grade 2 criteria is any leak with a leakage rate of 10 kg/hr or more.

In the final rule, any leak on the pipe body (including pipe-to-pipe connections) of a pipeline operating at or above 30% or more of SMYS is a grade 2 leak. This excludes leaks from non-pipe components, such as valve packing leaks. Additionally, grade 2 leaks include any leak on a gas transmission line in an HCA or on a gas transmission or regulated gas gathering line in a class 3 or class 4 location. Operators are not required to identify HCAs on gas gathering lines. Other leaks on gas transmission and regulated gas gathering lines that do not meet the grade 1 or grade 2 criteria may be classified as grade 3 leaks. Additionally, any leak of LPG that does not qualify as grade 1 leak is a grade 2 leak.

PHMSA requires any leak on a gas transmission or Type A gathering pipeline located in an HCA, Class 3, or Class 4 location to be repaired within 30 days of detection, or if permitting or parts are unavailable, the operator must reassess the leak once every 2 weeks and complete the repair as soon as practicable. For pipelines scheduled to be replaced, the repair may be postponed so long as the pipe segment is replaced within 2 years of leak discovery. However, monitoring requirements continue to apply until the leak has been eliminated. Any other identified grade 2 leaks must be repaired as soon as practicable but within 12 months of discovery unless an operator's integrity management program or other procedures require an expedited repair timeline. Operators must reevaluate each grade 2 leak, with a repair timeframe longer than 30 days, once every 6 months until the leak is repaired. Following an attempt at repair but before a leak has been eliminated in accordance with paragraph (g), the initial and subsequent rechecks required by that section may be used to satisfy the recheck requirements until the leak is eliminated.

§ 192.760(d): Grade 3 leaks.

PHMSA characterizes a grade 3 leak in paragraph (d) of this section, as any leak that does not meet its minimum grade 1 or grade 2 criteria. Grade 3 leaks may include leaks with a reading of less than 80 percent LEL in gas-associated substructures from which gas is unlikely to migrate, any reading of gas under pavement outside of wall-to-wall paved areas where it is unlikely that gas could migrate to the outside wall of a building, or a reading of less than 20 percent LEL in a confined space.

PHMSA requires an operator to complete repair of each grade 3 leak within an HCA or gas transmission or regulated gathering pipeline segments within a Class 3 or Class 4 location must be repaired within one year of detection. Other grade 3 leaks must be repaired within 36 months of leak detection. However, PHMSA does not require repair of a grade 3 leak that has a measured or calculated emission rate less than 5 SCFH. Similar to the leak extent criteria for grade 2 leaks, a measured leak extent less than 1800 square feet may be used instead of the 5 SCFH criteria, but only for belowground leaks on a pipeline operating at less than 20 percent of SMYS. See the discussion of grade 2 leaks for information on the required methodology for determining the leak extent of a leak. In addition to those two standard methods, a distribution operator may also use an alternative method determined to be equivalent to a leakage rate of 5 SCFH with notification to PHMSA in accordance with § 192.18. See the discussion of grade 2 leaks above for additional guidance on establishing the leak extent area. In the final rule, leaks that have been downgraded to grade 3 following a temporary repair or an ineffective attempt at a permanent repair under § 192.760(i)(1) are not eligible for this exception from repair requirements. In addition, an operator may continue to monitor a grade 3 leak provided the pipeline segment containing the leak is scheduled for replacement and is in fact replaced, within seven years of leak detection. Finally, PHMSA requires grade 3 leak be reevaluated every 12 months until the leak is eliminated. Similar to grade 2 leaks, following an attempt at repair but before a leak has been eliminated in accordance with paragraph (g), the initial and subsequent rechecks required by that section may be used to satisfy the reevaluation requirements for leak monitoring until the leak is eliminated.

§ 192.760(e) Scheduling repair of grade 2 and grade 3 leaks

Paragraph (e) of this section requires that an operator incorporate in written procedures and implement a methodology for prioritizing grade 2 and grade 3 leaks for repair based on risk to public safety or the environment. This methodology must include an analysis of the volume and migration of gas, proximity to buildings and subsurface structures, extent of pavement, soil type and conditions such as frost cap, moisture, and natural venting as well as scheduling with other planned maintenance and repairs to minimize emissions from leak repairs.

§ 192.760(f): Reevaluation following environmental change

Paragraph (f) of this section requires any known below ground grade 2 or grade 3 leak be reevaluated when changes to the environment may affect the venting or migration of gas or could allow gas to migrate to the outside wall of a building. These environmental changes may include ground freeze, heavy rain, flooding, new pavement, or any other changes that may impact leak behavior. The investigation is required at the time the operator becomes aware of the environmental change. These reevaluations may be made in the course of an operators written program to evaluate weather-related impacts to its system. Like other required leak reevaluations in this section, an operator must investigate the leak location and evaluate if the leak has become more hazardous based on the grading criteria in this section and the operator's procedures. If conditions meeting the definition of a higher-priority grade are discovered, the leak must be upgraded in accordance with paragraph (h) of this section.

§ 192.760(g): Post-repair recheck.

Paragraph (g) defines requirements for determining and documenting a complete and effective leak repair through a post-repair recheck. This recheck may be conducted immediately after the repair is complete for a grade 3 leak repair, a repair on an aboveground or submerged pipeline facility, or for an excavation damage caused leak where the extent of the damage is known. A leak repair that is not eligible for immediate recheck will be required to be rechecked no sooner than 14 days but no later than 30 days after the date of repair.

PHMSA requires that for a leak repair to be complete, an operator must perform a permanent repair and obtain, during a post-repair recheck, a gas concentration reading of less than 1 percent LEL (500 ppm for natural gas) at the leak location. Repair is also considered complete if the leak was eliminated through routine maintenance work or the pipe was replaced or permanently abandoned.

If a post-repair recheck yields a gas reading greater than 1 percent LEL but less than the most recent reading, the operator must perform additional rechecks every 30 days until the gas concentration reading is less than 1 percent. If a recheck shows a gas concentration greater than or equal to the most recent reading, the operator will need to investigate the repair to determine the source of the leakage and correct the repair. The operator may be required to upgrade the leak in accordance with this section based on the investigation.

As noted above, an operator may use these rechecks to meet applicable reevaluation requirements for a leak pending repair. Except for leaks that require biweekly reevaluation in accordance with paragraph (c)(4), this means that an operator is not required to separately perform regular reevaluation of leaks pending repair in addition to the rechecks required in this paragraph (g).

§ 192.760(h) and (i): Upgrading and downgrading.

Section 192.760(h) and (i) describe the repair deadlines and requirements for leaks that are upgraded or downgraded to higher or lower priority grades. Operators who receive information that a higher-priority grade condition exists on a previously graded leak will need to upgrade that leak to a higher-priority grade. For a leak that is upgraded, PHMSA requires that the deadline for the repair will be the earlier of either the remaining time based on the original leak grade, or the time allowed for repair for the upgraded leak measured from the time the operator receives information that a higher-priority grade condition exists. In other words, an operator will not be permitted to extend the repair deadline by upgrading a leak.

PHMSA also prohibits the downgrading of a leak unless either (1) a temporary repair has been made or a permanent repair to the pipeline has been attempted but gas was detected during the post-repair recheck required by paragraph (g) of this section or (2) the leak was initially incorrectly graded based on information available at the time the determination was made. If a leak was downgraded after the attempted permanent repair, the time period for completion of repair will be the remaining time allowed for repair under its new grade measured from the time the leak was initially detected. Leaks downgraded after a temporary repair or a failed initial attempt at permanent repair are ineligible for the grade 3 repair exception in § 192.760(d)(3)(ii).

§ 192.760(j): Recordkeeping.

Paragraph (j) of this section describes leak grading and repair recordkeeping requirements. PHMSA requires that records that document the investigation and grading history of each leak prior to completion of the repair are maintained for five years after the final post-repair inspection. These records include grading, reevaluation, rechecks, and any upgrades or downgrades. PHMSA also requires that records associated with the detection, remediation, and repair of each leak be maintained for the life of the pipeline unless a different interval for repair records is specified in § 192.709 for gas transmission lines. While regulated gas gathering lines are not generally subject to § 192.709, they may use the record retention schedule in that section for records required by this section. Repair records must include the location, timing, and repair or remediation necessary for each leak.

§ 192.763 Advanced Leak Detection Program.

PHMSA creates § 192.763 that requires operators of gas distribution, transmission, offshore gathering, and Types A, B, and C gathering pipelines to establish an Advanced Leak Detection Program (ALDP). An ALDP includes four elements: leak detection equipment, leak detection procedures, prescribed leakage survey frequencies, and program evaluation.

The first element in an ALDP is a list of leak detection equipment used to perform leakage surveys (including screening surveys using the leakage rate standard), pinpoint the origin of leak indications, and investigating leaks. Either the operator or the manufacturer must qualify listed equipment for use in leak detection tasks by validating that listed equipment meets the performance standards applicable to the equipment and its intended use. The specific requirements for qualifying leak detection equipment are delineated in paragraph (c) of this section, discussed below.

The second program element in paragraph (a)(2) of this section, requires the operator to have written procedures for performing leakage surveys (including screening surveys, if applicable), pinpoint leaks, and maintaining leak detection equipment. PHMSA requires that, at a minimum, the ALDP must include procedures for performing leakage surveys using each of the leak detection equipment included in an operator's ALDP. Additionally, the operator must define under which environmental conditions such as temperature, wind, time of day, precipitation, and humidity, the procedure and equipment may and may not be used. Operational parameters that must be considered include what type of facility or facilities a survey method is effective for, the effective range, and the dwell time or survey speed that is required for reliable readings.

Additionally, these procedures must be consistent with any instructions of the leak detection equipment manufacturer regarding environmental and operational conditions parameters for use. Consistent with the detection limits described at § 192.763(b), at a minimum these procedures must be capable of reliably detecting grade 1 and grade 2.

PHMSA requires that an operator's procedures provide for pinpointing the location of leak indications with the use of handheld leak detection equipment (§ 192.763(a)(2)(ii)). Equipment used for pinpointing leaks must generally (for onshore gas transmission, Types A, B, and C gathering, and distribution pipelines) have a minimum sensitivity of 5 ppm, 5 ppm-m, or 1 percent LEL depending on the location of the leak—these equipment performance standards are defined at paragraph (b)(4). For walking surveys, if a leak location was pinpointed with methods and equipment compliant with § 192.763(b)(4) during the initial survey, PHMSA does not expect an operator to re-survey the area to meet the requirement of this paragraph.

Paragraph (a)(2)(iii) describes "screening surveys" and requires an operator's screening survey procedures to include a follow-up investigation of all discovered indications of leaks to pinpoint the location of leaks in accordance with paragraphs (a)(2)(ii) and (b)(4) and to include criteria for prioritizing leak indications for follow-up investigation. A screening survey is a type of leakage survey where an operator uses the flow-rate standard applicable to the facility in paragraph (b) to identify leak indications for subsequent investigation. These methods include mobile ground lab surveys (typically for distribution lines), aerial and satellite-based surveys, and some continuous monitoring methods. Generally, these methods attempt to detect and quantify indications of a leak from a distance (e.g., via in-plume measurements or open-path laser/infrared detectors), compared with traditional surveys with handheld or mobile equipment which typically sample gas in the immediate vicinity of the source of the leak or probable migration paths. The prioritization requirement directs operators to schedule follow-up investigation of leak indications in order of public safety and environmental risk. For example, an operator should prioritize leak indications in the vicinity of buildings and those that exceed the volume-based grade 1 criteria for prompt investigation and repair.

PHMSA also requires that operators have procedures for the maintenance and calibration of leak detection equipment (§ 192.763(a)(2)(iv)). At a minimum the operator must follow the maintenance and calibration procedures recommended by the equipment manufacturer. PHMSA further requires that an operator recalibrate leak detection equipment following an indication of malfunction. Records documenting the calibration of each device and records of device malfunctions that indicated recalibration was necessary must be maintained for 5-years after the date the individual device is no longer used by the operator.

The final element of an ALDP detailed in paragraph (a)(3) requires an operator evaluate and document the effectiveness of the ALDP once every three calendar years, with an interval between updates not exceeding 39 months. Operators must evaluate elements of their ALDP considering, at a minimum, each of the following: the performance of leak detection equipment used, advances in leak detection technologies and practices, the number of leaks initially detected by third parties, the number of leaks and incidents overall, any changes on the operator's pipeline system, and estimated emissions from leaks. During this evaluation, operators must make changes to any program element necessary to locate and eliminate leaks in accordance with §§ 192.760 and 192.763 and maintain documentation of those changes for 5 years after the date change is made.

Paragraph (b) identifies performance standards for leak detection equipment and methods used to perform leakage surveys and follow-up surveys to pinpoint the source of leak indications (when required). Leakage survey requirements are organized by facility type, with one set of requirements for gas distribution lines and another for gas transmission and regulated gas gathering lines. Next, there are separate standards for leakage surveys of pipeline facilities located aboveground or inside of buildings (i.e., facilities that are exposed to the atmosphere and accessible to operator personnel without excavation); these requirements are applicable to any gas pipeline facility type. Finally, the rule includes standards for permitted methods for pinpointing the source of leak indications, which is required for screening surveys and other leakage survey methods where locating the source of the leak is not included as part of the initial survey.

For gas transmission and regulated gas gathering lines, paragraph (b)(1) requires leakage surveys meet one of the listed standards unless the alternative standards for aboveground and indoor piping in paragraph (b)(3) apply. Screening surveys performed using infrared or laser-based leak detection equipment; mobile, aerial, or satellite-based platforms; or fixed continuous monitoring sensors must meet a performance standard of detection of releases of 10 kg/hr or more with a 90 percent probability of detection. Any screening survey method using this performance standard must include a follow-up investigation to pinpoint the source of leak indications in accordance with paragraphs (a)(2)(ii) and (b)(4).

When performing leakage surveys with handheld leak detection equipment, each device must have a minimum sensitivity of 5 ppm or 5 ppm-m; though as noted below, alternative standards may apply to aboveground or indoor pipeline facilities. When performing a traditional leakage survey with leak detection equipment mounted on ground vehicles, each device must have a minimum sensitivity of 5 ppm or 5 ppm-m, the same as surveys with handheld equipment, but with the following additional conditions: the intakes for ppm measurement equipment (but not open-path devices measuring in ppm-m) must be located as near as practicable to the pipeline facility (i.e., at ground level), as required for all survey methods; the survey must be performed within the limits for speed and effective range necessary to ensure reliable detection of grade 1 and grade 2 leaks as noted in paragraphs (b)(1)(iii) and (a)(2)(i); and finally a follow-up investigation to pinpoint the source of leak indications discovered during the survey in accordance with paragraphs (a)(2)(ii) and (b)(4) must be performed.

For gas distribution pipelines, these standards are identical except that the performance standard for leak detection equipment used when performing screening surveys with a flow-rate standard is 0.2 kg/hr with a 90 percent probability of detection.

Paragraph (b)(3) allows a different set of performance standards for leakage surveys of portions of pipeline facilities that are aboveground or located inside of buildings. Unless specifically noted, these methods apply to all facility types, provided the facility is located aboveground or inside of a building. For these facilities, leakage surveys performed with handheld equipment must use equipment with a minimum sensitivity of 1% LEL (500 ppm for methane gas). Additionally (b)(4)(ii) allows operators to perform a leakage survey of exposed aboveground or indoor pipe by applying a soap solution directly to the pipeline and visually observing the probable leak location for bubbles and other visual indications of a leak. Paragraph (b)(3)(iii) permits an alternative sensitivity standard of 500 ppm or 500 ppm-m for aboveground and indoor piping subject to limitations similar to those adopted for performing vehicle-based surveys. Specifically, continuous monitoring may only serve as a leakage survey for pipeline facilities within the effective range of the device as defined in accordance with paragraph(a)(2), and each indication of a leak must be investigated and pinpointed in accordance with paragraphs (a)(2)(ii) and (b)(4). For equipment at the minimum sensitivity of 500 ppm, the effective range is likely very short, however it could be appropriate for surveys of short segments of exposed or indoor piping, and the effective range could be improved by using more sensitive equipment or open-path devices. Paragraph (b)(3)(iv) clarifies that non-optical continuous monitoring systems may be used to perform leakage surveys of aboveground gas transmission or regulated gas gathering lines; when using these methods the operator must meet the flow-rate standard of 10 kg/hr in paragraph (b)(1)(i) or use the notification process in paragraph (d) to request an alternative performance standard. Like all other continuous monitoring methods, any leak indication must be pinpointed in accordance with the requirements in paragraphs (a)(2)(ii) and (b)(4). Finally, paragraph (b)(3)(v) allows an operator to perform a leakage survey of aboveground facilities and facilities located inside of buildings with OGI performed in accordance with EPA requirements for performing OGI emissions monitoring surveys in Appendix K to 40 CFR 60, including compliance with requirements for the preparation, maintenance, and operation of the device. When using OGI in this manner to comply with gas pipeline leakage survey requirements in part 192, any "fugitive emission or leak," defined by the EPA as an emissions observed using the OGI instrument, is considered a "leak" for the purposes of complying with parts 191 and 192. OGI is not permitted for leakage surveys of gas distribution service lines, including customer meter assemblies.

Paragraph (b)(4) prescribes allowable methods for pinpointing the source of an indication of a leak. Any survey method that does not include locating the source of the leak on the pipeline as part of the initial leakage survey requires a follow-up investigation with handheld equipment to pinpoint the source of the leak. This likely includes any leakage survey other than a comprehensive leakage survey performed with handheld equipment and is explicitly required for all screening survey methods and any method using vehicle-mounted or stationary gas detectors. When pinpointing leaks with handheld equipment, a device with a sensitivity of 5ppm or 5 ppm-m must be used as near as possible to the probable source of the leak, except that equipment with a minimum sensitivity of 1 percent LEL (500 ppm for methane) is permitted for indications of leaks on non-buried pipelines and pipelines located inside of buildings. The source of leaks may also be located visually via a soap test—applying a soapy solution (or equivalent) directly to the pipeline. In the same vein, the source of leaks on pipelines located in and submerged below the waterline of a body of water may be located visually.

Paragraph (c) addresses requirements for qualifying leak detection equipment listed in the operator's ALDP. Prior to first use of a particular device in a leakage survey, an operator must be able to validate that each device listed in their ALDP meets the equipment performance standards listed at paragraph (b) applicable to the type of device and its intended use. This must be accomplished by testing with a known concentration or amount of gas. This test is required at least once. In the final rule, this testing may either be performed by the operator or, alternatively, the operator can provide evidence that this validation was performed by the equipment manufacturer. Records validating that a device meets the performance standard must be maintained for at least 5 years after the date that the particular model is no longer listed in the operator's ALDP.

Paragraph (d) allows operators to request use of an alternative performance standard, pursuant to the notification and PHMSA review procedures established in § 192.18. PHMSA requires that any notifications submitted under this provision must include, among other things, information about the location, design, gas being transported, operational parameters, environmental conditions, and material properties and history of the pipeline, the proposed alternative performance standard, and a description of any leak detection equipment and procedures that would be used.

Lastly, PHMSA includes an exemption in paragraph (e) that corresponds to similar language at § 192.706(a)(2), stating that the ALDP requirements do not apply to a pipeline transporting gas containing more than 50 percent of hydrogen gas, by volume.

§ 192.770 Minimizing emissions from gas transmission pipeline blowdowns.

PHMSA in a new § 192.770 requires gas transmission, offshore gathering, and Type A gathering pipeline operators minimize the intentional release of gas to the environment from planned activities which include repairs, construction, operations, or maintenance. PHMSA provides exemptions to this section in paragraph (c) for blowdowns with a volume less than or equal to 0.5 MMCF, during an even that would delay emergency response actions, testing of an emergency shutdown device, or response to an immediate repair condition under §§ 192.714(d) and 192.933(d)(1) or a grade 1 leak when minimization requirements are not practicable. PHMSA includes an exemption to minimizing a release of gas in accordance with this section would lead to a substantial negative impact to customers' health or safety due to a prolonged loss of gas supply. Operators using this exemption must provide notification to PHMSA and the appropriate state authority as early as practicable after the release with justification for the use of this exemption.

Paragraph (a) provides six available minimization methods operators may choose from to minimize emissions and a seventh alternative method that an operator may use if it is demonstrated to result in an emissions reduction of at least 50 percent compared to an unmitigated release for that planned activity. An operator may employ one or more of the available methods in combination with other methods listed. The first method is to reduce the volume of gas to be vented by minimizing the length of the pipeline segment that would be blown down through the installation and use of valves or control fittings. The second method is to route gas from the pipeline to other equipment for consumption as fuel gas. The third method is to reduce the pressure by the use of in-line compression. In-line compression allows an operator to reduce the pressure of the affected segment by isolating the pipeline segment upstream and using the downstream compressor station to reduce amount of gas necessary to be released. The fourth method is similar to the third method, except for using a compressor station, a mobile compressor unit is used to compress gas from the segment into an adjacent facility or storage vessel. The fifth method allows for gas to be transferred without compression to a lower-pressure system. If operators do not select methods (1) through (5), they have the option to choose an alternative method in (a)(6). The sole use of flaring is only permitted when the other available options in (a)(1) through (a)(5) are impractical, unsafe, or are calculated to result in higher CO_2 equivalent emissions than flaring.

For five years after the end of a release at paragraph (a), an operator must retain records that document the release and mitigation method(s) used. If the alternative method in paragraph (a)(6) is used, the documentation must include calculations demonstrating an emissions reduction of at least 50 percent compared to releasing gas to the atmosphere without minimization. If the sole use of flaring in paragraph (a)(7)—subject to the limitations in paragraph (b)—is employed, the documentation must include the justification for such use, including, if applicable, any supporting calculations demonstrating that each of the other methods result in higher carbon dioxide equivalent emissions compared to flaring. Documentation must include the justification for any release conducted without minimization in accordance with one of the exceptions in paragraph (c).

§ 192.1007 What are the required elements of an integrity management plan?

PHMSA amends § 192.1007(e)(1)(i) and (v) to delete existing references to § 192.703(c) since that paragraph now references the new grading criteria at § 192.760 and no longer refers to the term "hazardous leak. This is intended as an editorial amendment. For the purposes of evaluating DIMP performance in § 192.1007, the definition of the term hazardous leak at § 192.1001 remains applicable.

§ 193.2019 Mobile and temporary LNG facilities.

Section 193.2019(a) exempts operators of mobile and temporary LNG facilities from part 193 as long as the facilities comply with an LNG-specific standard that is incorporated by reference. Notwithstanding the existing exemption for mobile and temporary LNG facilities, PHMSA will now require compliance with a tailored version of the newly incorporated leakage survey requirements at § 193.2624, including requirements for addressing leaks and recordkeeping for these facilities. PHMSA is revising the proposed leakage survey requirements applicable to mobile and temporary LNG facilities to require operators of portable LNG facilities to perform leakage surveys at least one time within 48 hours of placing the facility in service in accordance with written procedures for performing and documenting leakage surveys, including procedures for eliminating leaks. The leakage surveys must also be performed in accordance with the leak detection method and equipment requirements at § 193.2624(b) and (c). Mobile and temporary LNG facilities may qualify for the exceptions related to equipment capability and leakage survey requirements in § 193.2624(e) and (f), respectively. PHMSA is also clarifying that the existing notification requirement to State agencies at § 193.2019(b) is required for all part 193-regulated mobile and temporary LNG facilities.

§ 193.2503 Operating procedures.

Section 193.2503 requires operators of part 193-regulated LNG facilities to have and follow written procedures for normal and abnormal operations. PHMSA is revising the proposed new paragraph (h) to require operators to have and follow procedures that include provisions for minimizing releases of natural gas and LNG, which includes procedures for minimizing emissions when conducting intentional releases in accordance with the new § 193.2523.

§ 193.2523 Minimizing emissions from blowdowns and boil-off.

PHMSA adds a new § 193.2523 to require operators of part 193-regulated LNG facilities to minimize natural gas and LNG emissions from intentional releases such as blowdowns and tank boil-off. At § 193.2523, PHMSA will permit the sole use of flaring as a method to minimize emissions only when other methods prescribed by this section are impractical, unsafe, or are calculated to result in higher carbon dioxide equivalent (CO_2 equivalent) emissions than flaring. PHMSA is also expanding the proposed circumstances in which an operator is not required to comply with the prescribed methods. Additionally, PHMSA is revising the proposed documentation requirements to require operators to maintain records of releases, including documenting the methods used to minimize the release and any justification and calculations supporting the use of certain methods. Records of unminimized releases performed under paragraph (c) of this section include documentation of the release and the justification for performing the release without minimization. These requirements will be applicable for intentional releases that occur after January 1, 2028.

§ 193.2605 Maintenance procedures.

Section 193.2605(b) requires operators of part 193-regulated LNG facilities to have and follow written maintenance procedures. PHMSA adds new subparagraph (b)(3) to incorporate the self-executing mandate in section 114 of the PIPES Act of 2020 that requires operators to update their procedures to provide for the elimination of leaks from pipeline facilities, including through the performance of leakage surveys in accordance with § 193.2624.

§ 193.2624 Leakage surveys.

PHMSA is adding a new § 193.2624 that requires operators of part-193 regulated LNG facilities to perform periodic leakage surveys on methane or LNG-containing components at least four times each calendar year, with a maximum interval between surveys not to exceed 4 ½ months. This leakage survey requirement will apply to part 193-regulated LNG facilities. PHMSA is revising the proposed leakage survey frequency to one time per calendar year for LNG facilities with a maximum individual container capacity of less than 264,000 gallons, or a total aggregate capacity of less than 1,056,000 gallons, and portions of LNG facilities with continuous methane monitoring.

The above methane leakage surveys will need to be performed with properly qualified leakage survey methods and leak detection equipment, including validation, calibration, and maintenance of the methods and equipment. PHMSA will require that leak detection equipment have a minimum sensitivity of 5 parts per million or 5 parts per million-meter. Less sensitive equipment is required for screening surveys, continuous monitoring, and pinpointing the locations of leak indications on certain components within LNG facilities. PHMSA is also revising its proposal to allow the use of OGI surveys using equipment and procedures that comply with EPA requirements in Appendix K of 40 CFR part 60, or other instruments meeting the requirements of EPA Method 21 described in Appendix A-7 for 40 CFR part 60. When using OGI in accordance with Appendix K of 40 part 60 to perform part 193 leakage survey, any indication of visible emissions observed from an OGI instrument (i.e., a fugitive emission as defined by the EPA) must be treated as a leak.

Additionally, the final rule requires prioritizing the elimination of leaks based on hazards to persons, property, and the environment in accordance with the operators' maintenance and abnormal operating conditions procedures, to include any repair schedules. PHMSA also includes an exemption from certain parts of new § 193.2624 for those components or portions of LNG facilities for which the operator determines the component or portion of LNG facility is subject to EPA fugitive methane emission monitoring and repair requirements or an EPA approved State, Tribal, or Federal plan.

§ 193.2639 Maintenance records.

Section 193.2639 requires each operator to keep a record at each LNG plant of the date and type of each maintenance activity performed on each component to meet the requirements of this part. Further, § 193.2639 requires operators to keep these maintenance records for a period of not less than five years. PHMSA adds a new paragraph (d) that requires the records required by paragraph (a) of this section to include leakage survey records pursuant to the new § 193.2624, including records of leakage surveys, validation tests, calibrations, maintenance, how the operator addressed any leaks or abnormal operating conditions, and if applicable, the documentation of which components or portions of the LNG facility are covered by EPA emissions monitoring standards or an EPA-approved State, Tribal, or Federal plan for existing sources, as proposed by the NPRM at § 193.2624(c) and included in this final rule at § 193.2624(f).

V. Regulatory Analyses and Notices

A. Legal Authority for this Rulemaking

This final rule is published under the authority of the Secretary of Transportation delegated to the PHMSA Administrator pursuant to 49 CFR 1.97. Among the statutory authorities delegated to PHMSA are those set forth in the Federal Pipeline Safety Statutes (49 U.S.C. 60101 et seq.) (authorizing, inter alia, issuance of regulations governing design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities) and section 28 of the Mineral Leasing Act, as amended (30 U.S.C. 185(w)(3)). For a complete listing of authorities, *see* 49 CFR 1.97.

This final rule implements several provisions of the PIPES Act of 2020, including sections 113 (codified at 49 U.S.C. 60102(q)), 114 (codified at 49 U.S.C. 60108(a)), and 118 (codified at 49 U.S.C. 60102(b)(5)). While section 113 of the PIPES Act of 2020 does not mandate that PHMSA issue leak detection and repair program requirements for Type C gas gathering pipelines in Class 1 locations, 49 U.S.C. 60101(b) and 60102 grant authorities to issue standards for the transportation of gas via any part 192-regulated gathering pipelines to protect public safety and the environment, which include Type C gas gathering pipelines. As explained in section II.B of this final rule, fugitive emissions from all gas gathering pipelines (including Type C gas gathering pipelines in Class 1 locations) are a significant source of methane emissions which directly harm the environment by contributing to climate change—which (as explained in section II.B of this final rule) itself entails public safety and environmental risks.

Further, as explained in section II.B of this final rule and discussed in further detail in the final RIA, releases of natural gas (particularly unprocessed natural gas from Type C and other gas gathering pipelines) contain HAPs and VOCs are particularly harmful to public safety and the environment.

Further, 49 U.S.C. 60117(c) authorizes PHMSA to require owners and operators of gas gathering, transmission, and distribution pipelines and other pipeline facilities to submit information (including, as appropriate, each of annual reports, incident reports, and intentional release reports, and NPMS information required in this final rule) required for regulation of those pipeline facilities under the Federal Pipeline Safety Statutes. Section 60117(c) also authorizes the Secretary to require owners and operators of Type R gas gathering pipelines to submit the same information to support future decision making regarding whether and to what extent to impose requirements in 49 CFR part 192 on those gas gathering pipelines.

B. Executive Orders 12866 and 14094; U.S. DOT Regulatory Policies and Procedures

E.O. 12866 ("Regulatory Planning and Review"),[599] as amended by E.O. 14094 ("Modernizing Regulatory Review"),[600] requires that agencies "should assess all costs and benefits of available regulatory alternatives, including the alternative of not regulating." Agencies should consider quantifiable measures and qualitative measures of costs and benefits that are difficult to quantify. Further, E.O. 12866 requires that "agencies should select those [regulatory] approaches that maximize net benefits (including potential economic,

[599] 58 FR 51735 (Oct. 4, 1993).
[600] 88 FR 21879 (April 11, 2023).

environmental, public health and safety, and other advantages; distributive impacts; and equity), unless a statute requires another regulatory approach." Similarly, U.S. DOT Order 2100.6A ("Rulemaking and Guidance Procedures") requires that regulations issued by PHMSA, and other U.S. DOT operating administrations, should consider an assessment of the potential benefits, costs, and other important impacts of the proposed action and should quantify (to the extent practicable) the benefits, costs, and any significant distributional impacts, including any environmental impacts.

E.O. 12866, as amended, and U.S. DOT Order 2100.6A require that PHMSA submit "significant regulatory actions" to the Executive Office of the President's Office of Management and Budget (OMB) for review. This action has been determined to be significant under E.O. 12866, as amended. It is also considered significant under U.S. DOT Order 2100.6A because of significant Congressional, State, industry, and public interest in pipeline safety. In addition, pursuant to Subtitle E of the Small Business Regulatory Enforcement Fairness Act of 1996 (also known as the Congressional Review Act[601]), the Office of Information and Regulatory Affairs has determined that this rule meets the criteria set forth in 5 U.S.C. 804(2). The final rule has been reviewed by OMB in accordance with E.O. 12866 and is consistent with the requirements of E.O. 12866, as amended, and U.S. DOT Order 2100.6A.

E.O. 12866, as amended, and U.S. DOT Order 2100.6A also require PHMSA to provide a meaningful opportunity for public participation, which reinforces requirements for notice and comment in the Administrative Procedure Act (APA, 5 U.S.C. 551 et seq.). In accordance with

[601] 5 U.S.C. 804(2).

the requirement, in the NPRM, PHMSA sought public comment on its proposed revisions to the Federal Pipeline Safety Regulations and the preliminary cost and benefit analyses in the PRIA, as well as any information that could assist in quantifying the costs and benefits of this rulemaking. Those comments are addressed in this final rule, and additional discussion about the costs and benefits of the final rule are provided within the RIA posted in the rulemaking docket.

The quantified benefits of the final rule consist of the climate benefits of avoided methane emissions and the market value of avoided natural gas losses. PHMSA expects additional, unquantified benefits including safety benefits from early detection of leaks before they can evolve into incidents and detection of integrity threats on gas transmission and gathering pipelines from right-of-way patrols. PHMSA also expects additional unquantified environmental and public health benefits associated with preventing releases of natural gas, and other flammable, toxic or corrosive gases, and expects these benefits to be important given the types of health effects resulting from exposure to air pollutants (*e.g.*, asthma and other respiratory effects, such as cancer).

The table below summarizes the annualized quantified costs and benefits for the provisions in the final rule at a 2 percent discount rate (discussed in further detail in the RIA for this final rule, available in the rulemaking docket):

Comparisons of the total annualized costs and benefits of the final rule (million 2023$, 2 percent discount)

Item	Gathering	Transmission	Distribution		Other Facilities	Total[1]	
			Lamb et al. (2015)	Weller et al. (2020)		Low	High
Benefits[2]	$728.6	$27.3	$282.7	$959.7	NE[3]	$1,038.7	$1,715.7
Costs	$43.3	$29.8	$257.0	$307.3	$6.4	$336.4	$386.7
Net benefits[4]	**$685.3**	**-$2.4**	**$25.7**	**$652.5**		**$702.2**	**$1,329.0**

NE: Not estimated
[1] Total costs and benefits are presented as a range to reflect different assumptions regarding leak incidence and methane emissions rate across pipe materials. The low estimate reflects distribution costs and benefits based on Lamb et al. (2015) whereas the high estimate reflects distribution costs and benefits based on Weller et al. (2020).
[2] For presentation purposes, climate benefits are estimated using the social cost of methane at a 2 percent discount rate. As shown in the regulatory impact analysis accompanying this rule, PHMSA also estimated the social cost of methane at other discount rates at values developed by EPA and an Interagency Working Group.
[3] PHMSA did not quantify and monetize the benefits of reducing methane emissions from LNG facilities and UNGSF, even though PHMSA expects the final rule requirements for these facilities to have additional benefits (e.g., reductions in methane emissions from conducting leak surveys at LNG facilities).
[4] Total may not add up due to independent rounding.

Benefits of the final rule will depend on, among other things, the degree to which compliance actions result in additional safety and gas release avoidance and mitigation measures, relative to the baseline, and the effectiveness of these measures in preventing or mitigating future releases or incidents from gas pipeline facilities subject to this final rule.

C. Executive Order 13132: Federalism

PHMSA analyzed this final rule in accordance with the principles and criteria contained in E.O. 13132 ("Federalism")[602] and the Presidential Memorandum ("Preemption") published in the Federal Register on May 22, 2009.[603] E.O. 13132 requires agencies to assure meaningful and

[602] 64 FR 43255 (Aug. 10, 1999).

[603] 74 FR 24693 (May 22, 2009).

timely input by State and local officials in the development of regulatory policies that may have "substantial direct effects on the States, on the relationship between the National Government and the States, or on the distribution of power and responsibilities among the various levels of government."

This final rule does not have a substantial direct effect on State and local governments, the relationship between the National Government and the States, or the distribution of power and responsibilities among the various levels of government. This final rule does not impose substantial direct compliance costs on State and local governments.

While the final rule may operate to preempt some State requirements, it would not impose any regulation that has substantial direct effects on the States, the relationship between the National Government and the States, or the distribution of power and responsibilities among the various levels of government. Section 60104(c) of Federal Pipeline Safety Laws prohibits certain State safety regulation of interstate pipelines. Under Federal Pipeline Safety Laws, States that have submitted a current certification under section 60105(a) can augment Federal pipeline safety requirements for intrastate pipelines regulated by PHMSA but may not approve safety requirements less stringent than those required by Federal law. A State may also regulate an intrastate pipeline facility that PHMSA does not regulate. In this instance, the preemptive effect of the regulatory amendments in this final rule is limited to the minimum level necessary to achieve the objectives of the Federal Pipeline Safety Laws. Therefore, the consultation and funding requirements of E.O. 13132 do not apply.

D. Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) requires Federal agencies to conduct a Final Regulatory Flexibility Analysis (FRFA) for a final rule subject to notice-and-comment rulemaking under the APA unless the agency head certifies that the proposed rule will not have a significant economic impact on a substantial number of small entities. E.O. 13272 ("Proper Consideration of Small Entities in Agency Rulemaking")[604] obliges agencies to establish procedures promoting compliance with the Regulatory Flexibility Act. U.S. DOT posts its implementing guidance on a dedicated webpage.[605] This final rule was developed in accordance with E.O. 13272 and U.S. DOT guidance to promote compliance with the Regulatory Flexibility Act and to ensure that the potential impacts of the rulemaking on small entities has been properly considered.

PHMSA conducted an FRFA, which has been made available in the docket within the RIA for this rulemaking. The FRFA builds on the Initial Regulatory Flexibility Analysis (IRFA) of the PRIA.

PHMSA describes and estimates the number of small entities to which the final rule will apply and provides an assessment of the compliance costs incurred by small entities. Given the changes PHMSA made to the rule since proposal, the analysis includes an update on the economic impact assessment that was presented in the IFRA and reviews uncertainties and

[604] 67 FR 53461 (Aug. 16, 2002).

[605] U.S. DOT, "Rulemaking Requirements Related to Small Entities," https://www.transportation.gov/regulations/rulemaking-requirements-concerning-small-entities (last accessed Sept 3, 2024).

limitations in the analysis. PHMSA will produce a compliance guide for small entities as required under the RFA for rules for which a finding of no significant impact is not certified.

E. National Environmental Policy Act

The National Environmental Policy Act (NEPA, 42 U.S.C. 4321 *et. seq.*) requires Federal agencies to consider the consequences of major Federal actions and prepare a detailed statement on actions significantly affecting the quality of the human environment. The Council on Environmental Quality implementing regulations (40 CFR parts 1500-1508) require Federal agencies to prepare an environmental assessment for a proposed action that is not likely to have significant effects or when the significance of the effects is unknown. U.S. DOT Order 5610.1C ("Procedures for Considering Environmental Impacts") establishes departmental procedures for evaluation of environmental impacts under NEPA and its implementing regulations.

PHMSA analyzed this final rule in accordance with NEPA, NEPA implementing regulations, and U.S. DOT Order 5610.1C. PHMSA prepared a final Environmental Assessment (EA) and an accompanying Finding of No Significant Impact (FONSI), determining that this action will not significantly affect the quality of the human environment. The reasonably foreseeable effects of the final rule will benefit the environment by reducing the occurrence, magnitude, and consequences of gas releases and associated methane emissions from gathering, transmission and distribution pipelines. A copy of the EA and FONSI for this action is available in the rulemaking docket.

F. Environmental Justice

E.O. 12898 ("Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations")[606] directs Federal agencies to take appropriate and necessary steps to identify and address disproportionately high and adverse effects of Federal actions on the health or environment of minority and low-income populations "[t]o the greatest extent practicable and permitted by law." U.S. DOT Order 5610.2C ("U.S. Department of Transportation Actions to Address Environmental Justice in Minority Populations and Low-Income Populations") establishes departmental procedures for effectuating E.O. 12898 promoting the principles of environmental justice through full consideration of environmental justice principles throughout planning and decision-making processes in the development of programs, policies, and activities, including PHMSA rulemaking.

E.O. 14096—"Revitalizing Our Nation's Commitment to Environmental Justice for All" was enacted on April 21, 2023. E.O. 14096 on environmental justice does not rescind E.O. 12898— "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations," which has been in effect since February 11, 1994, and is currently implemented through U.S. DOT Order 5610.2C.

PHMSA has evaluated this final rule under U.S. DOT Order 5610.2C, E.O. 12898, and E.O. 14096 and has determined it will not cause disproportionately high and adverse human health and environmental effects on minority and low-income populations. The final rule is

[606] 59 FR 7629 (Feb. 16, 1994).

national in scope; it is neither directed toward a particular population, region, or community, nor is it expected to adversely impact any particular population, region, or community. Rather, the rulemaking will reduce the safety and environmental risks associated with gas gathering, transmission, and distribution lines, many of which are located in the vicinity of environmental justice communities,[607] As discussed in the EA the regulatory amendments in this final rule will yield environmental, health, and safety benefits, thereby reducing the risks to minority and low-income populations, underserved and other disadvantaged communities.

G. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

PHMSA analyzed this final rule according to the principles and criteria in E.O. 13175 ("Consultation and Coordination with Indian Tribal Governments")[608] and U.S. DOT Order 5301.1 ("Department of Transportation Programs, Polices, and Procedures Affecting American Indians, Alaska Natives, and Tribes"). E.O. 13175 requires agencies to assure meaningful and timely input from Tribal government representatives in the development of rules that significantly or uniquely affect Tribal communities by imposing "substantial direct compliance costs" or "substantial direct effects" on such communities or the relationship or distribution of power between the Federal government and Tribes.

PHMSA assessed the impact of the final rule and determined that it will not significantly or uniquely affect Tribal communities or Indian Tribal governments. The rulemaking's

[607] See Emmanuel, et al., "Natural Gas Gathering and Transmission Pipelines and Social Vulnerability in the United States," 5:6 GeoHealth (June 2021), https://agupubs.onlinelibrary.wiley.com/toc/24711403/2021/5/6 (concluding that natural gas gathering and transmission infrastructure is disproportionately sited in socially-vulnerable communities).
[608] 65 FR 67249 (Nov. 9, 2000).

regulatory amendments have a broad, national scope; therefore, this final rule will not significantly or uniquely affect Tribal communities, much less impose substantial compliance costs on Native American Tribal governments or mandate Tribal action. Insofar as the rulemaking will improve safety and reduce public safety and environmental risks associated with gas pipelines, it will not impose disproportionately high adverse risks for Tribal communities. For these reasons, PHMSA has concluded that the funding and consultation requirements of E.O. 13175 and U.S. DOT Order 5301.1 do not apply.

H. Executive Order 13211

E.O. 13211 ("Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use")[609] requires Federal agencies to prepare a Statement of Energy Effects for any "significant energy action." E.O. 13211 defines a "significant energy action" as any action by an agency (normally published in the Federal Register) that promulgates, or is expected to lead to the promulgation of, a final rule or regulation (including a notice of inquiry, ANPRM, and NPRM) that (1)(i) is a significant regulatory action under E.O. 12866 or any successor order and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) is designated by the Administrator of the Office of Information and Regulatory Affairs (OIRA) as a significant energy action.

This final rule is a significant action under E.O. 12866, as amended; however, it is not likely to have a significant adverse effect on supply, distribution, or energy use, as further

[609] 66 FR 28355 (May 22, 2001).

discussed in the RIA. Further, OIRA has not designated this final rule as a significant energy action.

I. Paperwork Reduction Act

Pursuant to 5 CFR 1320.8(d), PHMSA is required to provide interested members of the public and affected agencies with an opportunity to comment on information collection and recordkeeping requests. Provisions in the Pipeline Safety: Gas Leak Detection and Repair Final Rule will trigger new reporting and notification requirements for operators of natural gas transmission, distribution, and gathering pipelines. New and revised reporting requirements are intended to improve the quality of the data available concerning pipeline leaks and other sources of emissions.

Reporting Releases of Gas

PHMSA will require pipeline operators to submit data on intentional and unintentional releases of gas with a volume of 0.5 MMCF released over 96 hours excluding certain events that had been reported as incidents under §§ 191.9 or 191.15. To collect this data, PHMSA is creating a new large-volume gas release report. Operators will be required to submit this data upon each occurrence of a release that meets the reporting requirement on a quarterly basis. These new large-volume release reports will provide valuable information on the primary sources and causes of vented emissions and the causes of large-volume leaks that do not qualify as incidents. This data will address information gaps in the current incident reporting requirements with respect to intentional releases and environmentally hazardous unintentional releases with release volumes of at least 0.5 MMCF within 96 hours. PHMSA estimates it will take 12 hours to prepare each report.

Annual Report Revisions

PHMSA will revise the existing gas transmission (GT), regulated gas gathering (GG), and gas distribution (GD) annual report forms to include reporting of leaks discovered and repaired by grade. Currently, these forms include data on leak repairs, however they lack data on leaks discovered. PHMSA estimates an added burden of 6 hours, per report, to submit the newly required data. The deadline to submit the GT and GG Annual Report will move to June 15 and the deadline to submit the GD Annual report will move to May 15.

Notification Requirements

PHMSA requires operators to make notifications in accordance with § 192.18 90 days in advance of using an alternative technology or assessment method. For certain notifications, operators may proceed only if they do not receive a letter objecting to the proposed use of other technology and/or methods.

Section 192.763(d) will allow operators to request to use an alternative advanced leak detection performance standard if the operator notifies, and receives no objection from, PHMSA, in accordance with § 192.18(c). The notification must include: mileage by system type; 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; the proposed performance standard; any safety conditions such as increased survey frequency; the leak detection equipment, procedures, and leakage survey frequencies the operator proposes to employ; and data on the sensitivity and the leak detection performance of the proposed alternative ALDP standard. PHMSA expects to receive 100 of these notifications annually with each notification taking 4 hours to prepare.

There are a few notification allowances tied to leak grading and repair. Section 192.760(c)(1)(viii)(C) allows an operator to notify PHMSA about using an alternative method for defining environmentally significant grade 2 leaks on a distribution line. Section 192.760(d)(2)(ii)(C) similarly allows an operator to notify PHMSA about using an alternative method for defining very small grade 3 leaks excepted from repair requirements.

Record Keeping Requirements

PHMSA will require operators to develop and maintain various records in conjunction with the new requirements in this final rule. Among those requirements, operators must develop written procedures for grading and repairing leaks according to § 192.760(a)(1) and (e); operators must document post-repair rechecks according to § 192.760(g); operators must record the history of each leak, including leak discovery, grading, reevaluations, upgrades, and downgrades, and maintain these records for a period of 5 years pursuant to § 192.760(j); records of repairs made under § 192.760 on gas transmission and regulated gas gathering lines must be retained in accordance with § 192.709; records of repairs on gas distribution lines under § 192.760 must be retained for the life of the pipeline (§ 192.760(j); operators must have a written Advanced Leak Detection Program in accordance with § 192.763; operators must also record leak detection equipment calibration (and re-calibration) and maintain these records for the life of the equipment pursuant to § 192.763(a)(2)(iv); operators must record the repair or replacement of a pressure relief device and maintain these records for the life of the device or specific component according to § 192.739(e); and records associated with blowdown mitigation requirements in § 192.770 must be retained for 5 years after the cessation of the release. PHMSA estimates that it will take each operator, on average, 80 hours annually to develop these records. PHMSA estimates that it will take operators 20 hours annually to maintain these records. This burden will be incurred by the total reporting community.

PHMSA will submit the following information collection requests to OMB for approval based on the requirements in this final rule. These information collections are contained in the pipeline safety regulations, 49 CFR parts 190 through 199. The following information is provided for each information collection: (1) Title of the information collection; (2) OMB control number; (3) Current expiration date; (4) Type of request; (5) Abstract of the information collection activity; (6) Description of affected public; (7) Estimate of total annual reporting and recordkeeping burden; and (8) Frequency of collection.

The information collection burden for the following information collections is estimated to be revised as follows:

1. Title: Incident and Annual Reports for Gas Pipeline Operators.

OMB Control Number: 2137-0522.

Current Expiration Date: 08/31/2026.

Abstract: This mandatory information collection covers the collection of data from operators of natural and other gas transmission and gathering pipelines, underground natural gas storage facilities, and liquefied natural gas (LNG) facilities for annual reports. 49 CFR 191.17 currently requires operators of natural gas transmission, offshore gathering, or regulated onshore gathering pipeline systems, Type R gathering pipeline systems, liquefied natural gas facilities, and underground natural gas storage facilities to submit an annual report by March 15, for the preceding calendar year.

PHMSA is revising this information collection in conjunction with the regulatory changes made in the Pipeline Safety: Gas Leak Detection and Repair final rule. PHMSA Form F 7100.2-1, Natural and Other Gas Transmission and Gathering Pipeline Systems Annual Report, is revised to collect the total number of leaks identified within a calendar year. PHMSA is also revising the deadline to submit PHMSA Form F 7100.2-1, the Natural and Other Gas Transmission and Gathering Pipeline Systems Annual Report to June 15 for the preceding calendar year.

Currently, the approved burden for this information collection is 2,445 respondents and 104, 596 burden hours. PHMSA estimates that 1,810 operators currently spend, on average, 54 hours completing form PHMSA F 7100.2-1. PHMSA expects these operators to spend an additional 6 hours reporting the newly requested data on the total number of leaks identified and estimated emissions within the calendar year. This will increase the reporting compliance burden on these operators from 54 hours annually to 60 hours annually to complete form PHMSA F 7100.2-1. This revision will add 10,860 hours, annually, to the overall burden for this information collection, bringing the overall burden for completing form F 7100.2-1 to 108,600 (60 hours x 1,810 responses).

Affected Public: All gas pipeline operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 2,445.

Total Annual Burden Hours: 115,456.

Frequency of Collection: Annual.

2. Title: Annual Report for Gas Distribution Operators.

OMB Control Number: 2137-0629.

Current Expiration Date: 06/30/2026.

Abstract: This information collection request requires operators of gas distribution pipeline systems to submit annual report data to the Office of Pipeline Safety in accordance with the regulations stipulated in 49 CFR Part 191 by way of form PHMSA F 7100.1-1. 49 CFR 191.11 currently requires operators of natural gas distribution pipeline systems to submit an annual report no later than March 15, each year, for the preceding calendar year. The annual report form collects data about the pipe material, size, and age. The form also collects data on leaks from these systems as well as excavation damages. PHMSA uses the information to track the extent of gas distribution systems and normalize incident and leak rates.

PHMSA is revising this information collection in conjunction with proposed regulatory changes made in the Pipeline Safety: Gas Leak Detection and Repair final rule. The requested revision would revise form PHMSA F 7100.1-1, the Gas Distribution Annual Report, to collect the total number of leaks discovered and repaired, by grade, within a calendar year.

Currently, the approved burden for this information collection is 1,446 respondents and 28,920 burden hours. PHMSA estimates that, currently, 1,446 operators spend 20 hours completing the Gas Distribution Annual report each year. PHMSA expects these operators to spend an additional 6 hours reporting the newly requested data on the total number of leaks discovered and repaired within the calendar year. Because of this, PHMSA expects the burden for completing form PHMSA F 7100.1-1 to increase to 26 (20+6) hours per report adding a total of 8,676 (6 hours x 1,446 operators) hours to the overall burden for this information collection.

Affected Public: Gas Distribution operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 1,446.

Total Annual Burden Hours: 37,596.

Frequency of Collection: Annual.

3. Title: Incident and Annual Reports for Gas Pipeline Operators.

OMB Control Number: 2137-0635.

Current Expiration Date: 06/30/2026.

Abstract: Operators of gas pipelines and LNG facilities are required to report incidents, on occasion, to PHMSA per the requirements in 49 CFR Part 191. This mandatory information collection covers the collection of incident report data from gas pipeline operators and operators of LNG facilities. The reports contained within this information collection support the Department of Transportation's strategic goal of safety. This information is an essential part of PHMSA's overall effort to minimize gas transmission, gathering, distribution, and liquefied natural gas pipeline failures.

PHMSA is revising this information in conjunction with the regulatory changes made in the Pipeline Safety: Gas Leak Detection and Repair final rule to include a new form, PHMSA F 7100.5, designed to collect data on intentional and unintentional releases of gas with a volume of .5 MMCF or greater released within a period of 96 hours.

Currently, the approved burden for this information collection is 999 responses and 4,456 burden hours. PHMSA expects to receive 393 of these new reports, on average, each year (109 gas transmission, 84 gas gathering, and 200 gas distribution), with each report estimated to require 12 hours to prepare. This will result in an added burden of 393 responses and 4,716 hours for this information collection.

Affected Public: All gas pipeline operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 1,392.

Total Annual Burden Hours: 9,172.

Frequency of Collection: On Occasion.

4. Title: Notification Requirements for Leak Detection and Repair.

OMB Control Number: PHMSA will request a new OMB Control No.

Current Expiration Date: TBD.

Abstract: A person owning or operating a gas pipeline facility is required to provide information to the Office of the Secretary of Transportation at the Secretary's request according to 49 USC 60117. The Pipeline Safety regulations contained within 49 CFR Part 192 require operators to make various notifications upon the occurrence of certain events. Pipeline operators are required to notify PHMSA in various instances pertaining to leak detection and repair activities. These notification requirements are necessary to help ensure safe operation of pipelines and ascertain compliance with gas pipeline safety regulations. These mandatory notifications help PHMSA to stay abreast of issues related to the health and safety of the nation's pipeline infrastructure.

PHMSA is creating this information collection request in conjunction with the regulatory changes made in the Pipeline Safety: Gas Leak Detection and Repair final rule which requires operators to notify PHMSA about using an extended leak survey interval, alternative methods for determining a leakage rate, using an alternative advanced leak detection performance standard, and exception from performing blowdown mitigation. PHMSA expects all gas pipeline operators to be subject to these notification requirements. PHMSA expects to receive 100 of these requests with each request taking 4 hours to prepare.

The final rule also allows an operator to notify PHMSA about extending the leak repair deadline requirement for an individual grade 2 or grade 3 leak. PHMSA estimates that it may receive 1,000 requests on average per year to extend the deadline for remedying leaks, with each of these requests requiring approximately 8 hours to prepare.

Affected Public: All gas pipeline operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 1,100.

Total Annual Burden Hours: 8,400.

Frequency of Collection: On Occasion

5. Title: Recordkeeping Requirements for Gas Pipeline Operators.

OMB Control Number: 2137-0049.

Current Expiration Date: 4/30/2026.

Abstract: A person owning or operating a natural gas pipeline facility is required to maintain records, make reports, and provide information to the Secretary of Transportation at the Secretary's request. This mandatory information collection request requires owners and/or operators of gas pipeline systems to make and maintain records in accordance with the requirements prescribed in 49 CFR Part 192 and to provide information to the Secretary of Transportation at the Secretary's request. Certain records are maintained for a specific length of time while others are required to be maintained for the life of the pipeline. PHMSA uses these records to verify compliance with regulated safety standards and to inform the agency on possible safety risks.

PHMSA is revising this information to align with the regulatory changes made in the Pipeline Safety: Gas Leak Detection and Repair final rule which includes various recordkeeping requirements for operators pertaining to leak detection and remediation activities.

Affected Public: All gas pipeline operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 3,867,101

Total Annual Burden Hours: 1, 904,157

Frequency of Collection: On Occasion

Requests for copies of these information collections should be directed to Angela Hill at *angela.hill@dot.gov.*

J. Unfunded Mandates Reform Act of 1995

The Unfunded Mandates Reform Act (UMRA, 2 U.S.C. 1501 et seq.) requires agencies to assess the effects of Federal regulatory actions on State, local, and Tribal governments, and the private sector. For any NPRM or final rule that includes a Federal mandate that may result in the expenditure by state, local, and Tribal governments, in the aggregate of $100 million or more (in 1996 dollars) in any given year, the agency must prepare, amongst other things, a written statement that qualitatively and quantitatively assesses the costs and benefits of the Federal mandate.

PHMSA expects this final rule would impose compliance costs of $100 million or more (in 1996 dollars) on private sector entities. PHMSA has conducted an assessment (within the RIA in the rulemaking docket) of the final rule and has concluded that the regulatory amendments in the final rule will yield an appropriate balancing of costs and benefits.

K. Privacy Act Statement

In accordance with 5 U.S.C. 553(c), PHMSA solicits comments from the public to better inform its rulemaking process. PHMSA posts these comments, without edit, including any personal information the commenter provides, to regulations.gov, as described in the system of records notice (DOT/ALL–14 FDMS), which can be reviewed at dot.gov/privacy.

L. Regulation Identifier Number

A regulation identifier number (RIN) is assigned to each regulatory action listed in the Unified Agenda of Federal Regulations. The Regulatory Information Service Center publishes the Unified Agenda in April and October of each year. The RIN number contained in the heading of this document can be used to cross-reference this action with the Unified Agenda.

M. Executive Order 13609 and International Trade Analysis

E.O. 13609 ("Promoting International Regulatory Cooperation")[610] requires agencies consider whether the impacts associated with significant variations between domestic and international regulatory approaches are unnecessary or may impair the ability of American business to export and compete internationally. In meeting shared challenges involving health, safety, labor, security, environmental, and other issues, international regulatory cooperation can identify approaches that are at least as protective as those that are or would be adopted in the absence of such cooperation. International regulatory cooperation can also reduce, eliminate, or prevent unnecessary differences in regulatory requirements.

Similarly, the Trade Agreements Act of 1979 (Pub. L. 96-39), as amended by the Uruguay Round Agreements Act (Pub. L. 103-465), prohibits Federal agencies from establishing any standards or engaging in related activities that create unnecessary obstacles to the foreign commerce of the United States. For purposes of these requirements, Federal agencies may participate in the establishment of international standards, so long as the standards have a

[610] 77 FR 26413 (May 4, 2012).

legitimate domestic objective, such as providing for safety, and do not operate to exclude imports that meet this objective. The statute also requires consideration of international standards and, where appropriate, that they be the basis for U.S. standards.

PHMSA engages with international standards setting bodies to protect the safety of the American public. PHMSA has assessed the effects of the final rule and has determined that its regulatory amendments will not cause unnecessary obstacles to foreign trade.

N. Cybersecurity and Executive Order 14028

E.O. 14028 ("Improving the Nation's Cybersecurity")[611] directed the Federal government to improve its efforts to identify, deter, and respond to "persistent and increasingly sophisticated malicious cyber campaigns." Accordingly, PHMSA has assessed the effects of this final rule to determine what impact the regulatory amendments may have on cybersecurity risks for pipeline facilities.

PHMSA's regulatory amendments would not require pipeline operators to generate new security-sensitive records. Most of the pipeline facilities subject to the leak detection and repair requirements (and associated recordkeeping requirements) are already subject to such requirements—this final rule simply enhances and expands those requirements. While computerized continuous or remote monitoring systems for pipeline facilities could be more vulnerable to cyber-attack than other technologies, the final rule does not prescribe the use of any particular leak detection technology within operator advanced leak detection programs.

[611] 86 FR 26633 (May 17, 2021).

PHMSA's regulatory amendments require operators to evaluate remote and real-time leak detection technologies as one potential approach when operators are designing the portfolio of technologies to be used to satisfy the ALDP requirements, but ultimately operators can choose to adopt or decline such technologies.

Operators affected by these requirements may also be subject to cybersecurity requirements and guidance under Transportation Security Administration (TSA) Security Directives,[612] as well as any new requirements resulting from ongoing TSA efforts to strengthen cybersecurity and resiliency in the pipeline sector, as discussed within an advance notice of proposed rulemaking published in November 2022.[613] The Cybersecurity & Infrastructure Security Agency (CISA) and the Pipeline Cybersecurity Initiative (PCI) of the U.S. Department of Homeland Security also conduct ongoing activities to address cybersecurity risks to U.S. pipeline infrastructure and may introduce other cybersecurity requirements and guidance for gas pipeline operators.[614]

PHMSA has considered the effects of the final rule and has determined that its regulatory amendments would not materially affect the cybersecurity risk profile for pipeline facilities.

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[612] E.g., TSA, "Ratification of Security Directive," 86 FR 38209 (July 20, 2021) (ratifying TSA Security Directive Pipeline-2012-01, which requires certain pipeline owners and operators to conduct actions to enhance pipeline cybersecurity).

[613] TSA, ANPRM "Enhancing Surface Cyber Risk Management," 87 FR 73527 (Nov. 30, 2022).

[614] E.g., CISA, National Cyber Awareness System Alerts, https://www.cisa.gov/uscert/ncas/alertshttps://www.cisa.gov/uscert/ncas/alerts (last accessed June 20, 2024).

O. Severability

In this amended leak detection and repair standard, PHMSA provides multiple, mutually reinforcing provisions to address a series of issues related to safety and environmental hazards on regulated gas pipelines, with a focus on detection, grading, and repair of leaks. While the full benefits of this rule will derive from all of the provisions operating holistically, each discrete provision individually provides meaningful improvement to pipeline safety over the prior regulations and is separately warranted and cost-justified. Further, each provision can technically operate separately from the others, as designed by PHMSA and consistent with the existing requirements throughout parts 192 and 193. Therefore, PHMSA finds that each provision of this final rule is severable from the others and able to function independently, and PHMSA would have promulgated each provision independently from the others. For example, grade 1 leaks can be repaired with or without a requirement for the grading of grade 3 leaks, and enhanced patrolling requirements would have demonstrable benefits regardless of whether expanded repair requirements were being adopted in this final rule. Certain mutually-reinforcing provisions such as the enhanced leakage survey and patrolling requirements would be credited with a greater share of estimated benefits if being promulgated alone.

As applied to the various subsets of gas transmission, gathering, and distribution pipelines, UNGSFs, and LNG facilities, the standard is severable from each of the other subsets. This amended leak detection and repair standard has been calibrated to the technical, operational, and risk profile nuances of each of the different types of PHMSA-regulated pipeline facilities. Accordingly, while PHMSA believes the rule is most beneficial with all provisions together, in the event a court was to invalidate one or more of the discrete provisions of this rule, PHMSA intends the provisions and parameters of this rule to be severable and the remaining provisions to continue to function.

List of Subjects

49 CFR Part 191

Natural gas, Pipeline safety, Reporting and recordkeeping requirements.

49 CFR Part 192

Natural gas, Pipeline Safety, Safety.

49 CFR Part 193

Pipeline Safety, Reporting and recordkeeping requirements.

In consideration of the foregoing, PHMSA amends 49 CFR parts 191, 192, and 193 as follows:

PART 191—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE; ANNUAL, INCIDENT, AND OTHER REPORTING

1. The authority citation for part 191 continues to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5121, 60101 *et. seq.,* and 49 CFR 1.97.

2. In § 191.3:

a. Revise paragraph (1)(ii) in the definition of "Incident"; and

b. Add the definition of "Large-volume gas release" in alphabetical order.

The revision and addition read as follows:

§ 191.3 Definitions.

* * * * *

Incident * * *

(1) * * *

(ii) Estimated property damage of $122,000 or more, including loss to the operator and others, or both, but excluding each of the cost of gas lost, the cost to acquire permits, and the cost to remove and replace non-operator infrastructure that was not damaged by the release. For adjustments for inflation observed in calendar year 2021 onwards, changes to the reporting threshold will be posted on PHMSA's website. These changes will be determined in accordance with the procedures in appendix A to part 191.

* * * * *

Large-volume gas release means any intentional or unintentional release of gas from a gas pipeline facility (as that term is defined in § 192.3) of 500,000 cubic feet of gas or greater released within a period of 96 hours, excluding the estimated volume of gas combusted intentionally in a flare or as fuel gas.

* * * * *

§ 191.11 [Amended]

3. In § 191.11(a), remove the term "March" and add in its place the term "May".

4. Revise § 191.17(a)(1) to read as follows:

§ 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, for the preceding calendar year.

*   *   *   *   *

5. Add § 191.19 to read as follows:

§ 191.19 Large-volume gas release report.

(a) Each operator of a gas pipeline facility must report large-volume gas releases on DOT Form PHMSA-F 7100.5. The reporting deadlines for large-volume gas release reports are as follows:

(1) Submit reports quarterly as noted in Table 1 to § 191.19.

Table 1 to § 191.19

Date release became reportable	Report deadline
January 1 through March 31	April 30
April 1 through June 30	July 31
August 1 through September 30	October 31
October 1 through December 31	January 31

(2) Reporting of large volume gas releases is required for intentional releases that become reportable on or after [insert date 24 months after the effective date of the final rule].

(3) Reporting of large volume gas releases is required for unintentional releases that become reportable on or after January 1, 2028.

(b) A large-volume gas release report is not required if an incident report has already been submitted under this part for the same event.

PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

6. The authority citation for part 192 continues to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5103, 60101 et. seq., and 49 CFR 1.97.

7. In § 192.3, add the definitions of "Confined space," "Gas-associated substructure," "Lower explosive limit (LEL)," "Substructure," "Tunnel," and "Wall-to-wall paved area" in alphabetical order to read as follows:

§ 192.3 Definitions.

*   *   *   *   *

Confined space is a space that (1) is large enough and configured so that a person can bodily enter; and (2) has limited or restricted means for entry or exit; and (3) is not designed for continuous occupancy. These include vaults, catch basins, and manholes.

*   *   *   *   *

Gas-associated substructure means a substructure that is part of an operator's pipeline facility but that is not itself designed to contain gas under pressure (e.g., a valve box, vault, test box, vented casing pipe).

*   *   *   *   *

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.

*   *   *   *   *

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; 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.

*   *   *   *   *

8. In § 192.9

a. Revise and republish paragraph (d),

b. Republish the introductory text of paragraph (e),

c. Revise and republish paragraph (e)(1), and

d. Revise and republish paragraph (f)(1),

e. Add paragraphs (g)(6) through (g)(8).

The revisions and additions read as follows:

§ 192.9 What requirements apply to gathering pipelines?

* * * * *

(d) *Type B lines*. An operator of a Type B regulated onshore gathering line must comply with the following requirements:

(1) If a line is new, replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of this part applicable to transmission lines. Compliance with §§ 192.67, 192.127, 192.179(e) and (f), 192.205, 192.227(c), 192.285(e), 192.319(d) through (g), 192.506, 192.634, and 192.636 is not required;

(2) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines, except the requirements in §§ 192.461(f) through (i), 192.465(d) and (f), 192.473(c), 192.478, 192.485(c), and 192.493;

(3) If the pipeline contains plastic pipe or components, the operator must comply with all applicable requirements of this part for plastic pipe components;

(4) Prepare, review, update, and follow a manual of written procedures for carrying out the part 192 requirements applicable to the pipeline facility in accordance with this section and

complying with §§ 192.605(b)(4), (b)(13), and § 192.605(d). The manual must be prepared, reviewed, updated, and made available in accordance with the requirements in § 192.605(a).

(5) Carry out a damage prevention program under § 192.614;

(6) Develop and implement procedures for emergency plans in accordance with the requirements of § 192.615, effective as of October 4, 2022;

(7) Establish a public education program under § 192.616;

(8) Establish the MAOP of the line under § 192.619(a), (b), and (c);

(9) Investigate, grade, repair, and document leaks and leak repairs in accordance with §§ 192.703(c) through (f), 192.709, and 192.760 applicable to gas transmission lines;

(10) Conduct patrols in accordance with § 192.705(a) and (c) at least once each calendar year, with an interval between patrols not to exceed 15 months;

(11) Conduct leakage surveys in accordance with § 192.706 within an advanced leak detection program in accordance with § 192.763; and

(12) Maintain pressure relief devices in accordance with § 192.739(c) and retain maintenance records in accordance with § 192.739(d).

(e) *Type C lines.* The requirements for Type C gathering lines are as follows.

(1) An operator of a Type C onshore gathering line with an outside diameter greater than or equal to 8.625 inches must comply with the following requirements:

(i) Except as provided in paragraph (h) of this section for pipe and components made with composite materials, the design, installation, construction, initial inspection, and initial testing of a new, replaced, relocated, or otherwise changed Type C gathering line, must be done in accordance with the requirements in subparts B through G and J of this part applicable to transmission lines. Compliance with §§ 192.67, 192.127, 192.179(e) and (f), 192.205, 192.227(c), 192.285(e), 192.319(d) through (g), 192.506, 192.634, and 192.636 is not required;

(ii) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines, except the requirements in §§ 192.461(f) through (i), 192.465(d) and (f), 192.473(c), 192.478, 192.485(c), and 192.493;

(iii) Prepare, update, and follow a manual of written procedures for carrying out the part 192 requirements applicable to the pipeline facility in accordance with this section and complying with §§ 192.605(b)(4), (b)(13), and, if applicable, § 192.605(d). The manual must be prepared, reviewed, updated, and made available in accordance with the requirements in § 192.605(a).

(iv) Carry out a damage prevention program under § 192.614;

(v) Develop and implement procedures for emergency plans in accordance with the requirements of 49 CFR 192.615, effective as of October 4, 2022;

(vi) Develop and implement a written public awareness program in accordance with § 192.616;

(vii) Grade, investigate, repair, and document leaks and leak repairs in accordance with §§ 192.703(c) through (f), 192.709, and 192.760 applicable to gas transmission lines;

(viii) Conduct patrols in accordance with § 192.705(a) and (c) at least once each calendar year, with an interval between patrols not to exceed 15 months; and

(ix) Conduct leakage surveys in accordance with § 192.706(a) within an advanced leak detection program in accordance with § 192.763. Leakage surveys must be performed once each calendar year, but with an interval between surveys not to exceed 15 months. If a Type C pipeline segment meets the criteria for exception under paragraph (f)(1) of this section, that segment may instead be surveyed once every 5 calendar years with an interval between surveys not exceeding 63 months. The leakage survey must be performed when the pipeline is in operation;

(x) Install and maintain line markers according to the requirements for transmission lines in § 192.707; and

(xi) Maintain pressure relief devices in accordance with § 192.739(c) and retain maintenance records in accordance with § 192.739(d).

*   *   *   *   *

(f) *Exceptions.* (1) Compliance with paragraphs (e)(1)(ii), (vi), and (x), and (e)(2)(i) and (ii) of this section is not required for pipeline segments that are 16 inches or less in outside diameter if one of the following criteria are met:

(i) *Method 1.* The segment is not located within a potential impact circle containing a building intended for human occupancy or other impacted site. The potential impact circle must be calculated as specified in § 192.903, except that a factor of 0.73 must be used instead of 0.69. The MAOP used in this calculation must be determined and documented in accordance with paragraph (e)(2)(ii) of this section.

(ii) *Method 2.* The segment is not located within a class location unit (*see* § 192.5) containing a building intended for human occupancy or other impacted site.

(g) * * *

(6) The compliance timelines in § 192.703(f) apply to regulated gas gathering lines subject to the requirements listed in that section.

(7) Compliance with patrol requirements for Type B and Type C gathering lines in paragraphs (d)(10) and (e)(1)(viii) is required beginning January 1, 2028.

(8) For procedure manual requirements for Type B and Type C gathering lines in paragraphs (d)(4) and (e)(1) and emergency plan requirements for Type B gathering lines in paragraph (d)(6), develop procedures and programs by [insert date 18 months after date of publication] and begin compliance on January 1, 2028.

* * * * *

9. In § 192.12, revise paragraph (c) to read as follows:

§ 192.12 Underground natural gas storage facilities.

* * * * *

(c) *Procedural manuals.* Each operator of an UNGSF must prepare and follow for each facility one or more manuals of written procedures for conducting operations, maintenance, and emergency preparedness and response activities under paragraphs (a) and (b) of this section. Such manuals must include procedures for eliminating leaks that represent an existing or probable hazard to public safety, property, or the environment, and minimizing releases of natural gas. Each operator must keep records necessary to administer such procedures and review and update these manuals at intervals not exceeding 15 months, but at least once each calendar year. Each operator must keep the appropriate parts of these manuals accessible at locations where UNGSF work is being performed. Each operator must have written procedures in place before commencing operations or beginning an activity not yet implemented.

* * * * *

10. In § 192.18, revise paragraph (c) to read as follows:

§ 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, 192.607, 192.607, 192.619, 192.624,192.632, 192.634, 192.636, 192.710, 192.712, 192.714, 192.745, 192.760 , 192.763, 192.917, 192.921, 192.927, 192.933, or 192.937, 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.

*   *   *   *   *

11. In § 192.199, revise the section heading, revise paragraph (f), and-add paragraph (i) to read as follows:

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

*   *   *   *   *

(f) Be designed and installed so that the size of the openings, pipe, and fittings located between the system to be protected and the pressure relieving device, and the size of the vent line, are adequate to prevent hammering of the valve, impairment of relief capacity, and damage to the valve, interconnected piping, or other related components;

*   *   *   *   *

(i) If new, replaced, or relocated after January 1, 2028, be designed and configured to minimize releases of gas in accordance with each of the following:

(1) The configuration of the set and reseat pressures of the pressure relief device and the location where pressures are measured must 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 reseat pressures, compatible with the composition of transported gas, and suitable for reliable operation in expected operating and environmental conditions.

(3) The design for a pressure relief device and piping associated with the device must include valves necessary to isolate the device from the pipeline facility to facilitate testing and maintenance of the device.

(4) This paragraph (i) does not apply to service regulators with an internal relief or passive pressure relief or limiting device that do not release gas into the atmosphere on distribution systems.

12. In § 192.605, add paragraph (b)(13) to read as follows:

§ 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 releases of natural gas from pipelines, as well as remediating or replacing pipelines known to leak based on their material, design, or past operating and maintenance history.

*   *   *   *   *

13. In § 192.617, add paragraph (e) to read as follows:

§ 192.617 Investigation of failures and incidents.

*   *   *   *   *

(e) *Failure defined*. For the purposes of this section, the term failure means an event in which any portion of a pipeline becomes 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.

14. In § 192.703, revise paragraph (c) and add paragraphs (d) and (e) to read as follows:

§ 192.703 General.

* * * * *

(c) Each leak must be graded and repaired 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 (i) and (j)(1) for leak grading and repair, and 192.763 for advanced leak detection programs, is not required for a compressor station on a gas transmission or gathering pipeline that meets both of the following conditions:

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

(i) 40 CFR 60.5397a (including alternative means approved through the process described by the U.S. Environmental Protection Agency (EPA) under 40 CFR 60.5398a or 60.5399a), or 40 CFR 60.5397b (including alternative test methods approved under 60.5398b and alternative means approved through the process described by the EPA under 40 CFR 60..5399b); or

(ii) An EPA-approved State or Tribal plan, or Federal plan, which includes methane emissions monitoring and repair standards equivalent to the model rule presumptive standards in 40 CFR 60.5397c (including alternatives approved according to 40 CFR 60.5398c).

(2) The facility is downstream of the inlet of the first block valve entering the compressor station and upstream of the outlet of the last block valve exiting the compressor station. If applicable, this refers to the valves covered by the emergency shutdown system as required in § 192.167 for station isolation from the pipeline or covered by station overpressure protection if an emergency shutdown system is not present.

(e) Compliance with § 192.760 is not required for a pipeline transporting gas containing more than 50 percent of hydrogen gas by volume, but any leak that represents an existing or probable hazard to persons or property must be promptly repaired.

(f) A rule published in the Federal Register on [insert date of publication of the final rule], effective [insert effective date] resulted in revisions to this subpart. The compliance timelines for the amendments from that final rule during the implementation period ending January 1, 2028, are defined as follows:

(1) Prior to the compliance date listed in the second column of Table 1 to § 192.703, an operator must either comply with either the applicable requirements of this subpart in effect on [insert date of publication of the final rule], or the amended requirements of this subpart from the final rule published on [insert date of publication of the final rule].

(2) After the compliance date listed in the second column of Table 1 to § 192.703, compliance with the amended requirements of this subpart from the final rule published on **[insert date of publication of the final rule]** is required.

Table 1 to § 192.703

Amended Section	Compliance Date
§ 192.703(c)	January 1, 2028
§ 192.703(d)	[insert effective date of the final rule]
§ 192.705	January 1, 2028
§ 192.706	January 1, 2028
§ 192.723	January 1, 2028
§ 192.739(c) and (d)	January 1, 2028
§ 192.760	January 1, 2028, except leaks existing on or before January 1, 2028, must be managed in accordance with § 192.760(a)(3).
§ 192.763	Develop a written program no later than **[insert date 18 months after the date of publication of the final rule]**. Compliance with the written program is not required until January 1, 2028.
§ 192.770	January 1, 2028

15. In § 192.705, revise paragraph (b) to read as follows:

§ 192.705 Transmission lines: Patrolling.

* * * * *

(b) Operators must conduct patrols 6 times each calendar year at intervals not exceeding 75 days in Class 3 and 4 locations and 4 times each calendar year in Class 1 and 2 locations at an interval not exceeding 135 days.

* * * * *

16. Revise § 192.706 to read as follows:

§ 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 and leaks must be managed in accordance with § 192.760, except as follows:

(1) Human or animal senses may be used instead of leak detection equipment for pipeline segments submerged below the waterline.

(2) Leakage surveys of pipelines transporting gas containing more than 50 percent of hydrogen gas by volume must use leak detection equipment, but compliance with § 192.763 is not required.

(b) *Frequency of surveys.* Except as provided in paragraph (b)(2) of this section, leakage surveys must be performed at the intervals listed in table 1 to paragraph (b). When more than one survey interval applies, the most frequent interval applicable to the pipeline segment applies.

(1) Table 1 to paragraph (b): Survey frequency for gas transmission lines

<table>
<tr><th>Facility</th><th>Class 1</th><th>Class 2</th><th>Class 3</th><th>Class 4</th></tr>
<tr><td>(i) Valves, flanges, pipeline tie-ins with valves and flanges, launcher, and receiver facilities.</td><td rowspan="3">twice each calendar year, at intervals not exceeding 7 ½ months</td><td rowspan="3">twice each calendar year, at intervals not exceeding 7 ½ months</td><td rowspan="3">twice each calendar year, at intervals not exceeding 7 ½ months</td><td rowspan="3">four times each calendar year, at intervals not exceeding 4 ½ months</td></tr>
<tr><td>(ii) Pipelines known to leak based on material, design, or past operating and maintenance history.</td></tr>
<tr><td>(iii) Transmission lines in an HCA.</td></tr>
</table>

(iv) Pipelines transporting gas in conformity with § 192.625 without an odor or odorant, or	once per calendar year, but with an interval between surveys not to exceed 15 months	once per calendar year, but with an interval between surveys not to exceed 15 months	twice each calendar year, at intervals not exceeding 7 ½ months	four times each calendar year, at intervals not exceeding 4 ½ months
(v) All other pipelines.	Once per calendar year, but with an interval between surveys not to exceed 15 months			

(2) *Pipelines in the Alaskan North Slope*. For pipelines in Alaska located north of the Brooks Range, only paragraphs (b)(1)(iv) and (v) apply.

17. Revise § 192.723 to read as follows:

§ 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 of distribution lines 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 gas, electric, telephone, sewer, water, or other system manholes; cracks in the pavement and sidewalks; and at other locations that provide an opportunity for finding gas leaks.

(c) *Non-business districts.* Leak surveys outside of business districts must be performed as follows:

(1) Unless a different survey frequency is required under paragraphs (c)(2) of this section, perform a leakage survey at least once every 5 calendar years, at intervals not exceeding 63 months.

(2) Leakage surveys must be conducted at least once every calendar year, at intervals not exceeding 15 months, for the following categories of pipelines located outside of buildings:

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

(ii) Pipelines known to leak based on their material (including cast iron, unprotected steel, wrought iron, and historic plastics with known issues), design, or past operating and maintenance history; or

(iii) Gas distribution pipeline systems protected by a distributed anode system, in the area of deficient readings identified during a cathodic protection survey/test pursuant to § 192.463 and appendix D until the cathodic protection deficiency is remediated. The initial leakage survey must be conducted no later than 12 months from the date the deficient cathodic protection reading was found.

(d) *Extreme Weather or Natural Disaster Surveys.* A leakage survey must be performed on a pipeline segment following an extreme weather event or natural disaster with a likelihood of causing damage to that pipeline facility by the scouring or movement of the soil surrounding the pipeline or movement of the pipeline. Examples of events include a named tropical storm or hurricane; a flood that exceeds the river, shoreline, or creek high-water banks in the area of the pipeline; a landslide in the area of the pipeline; or an earthquake in the area of the pipeline. The survey must be initiated 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 required to perform the leakage survey are available.

*   *   *   *   *

18. In § 192.739, add paragraphs (c) and (d) to read as follows:

§ 192.739 Pressure limiting and regulating stations: inspection and testing.

*   *   *   *   *

(c) When an operator discovers a malfunction of a pressure relief device during the inspections and tests required by paragraph (a) of this section or otherwise, the operator must provide for safety, evaluate the malfunction, and adjust, repair, or replace each pressure relief device found to have malfunctioned. For the purpose of this section, a malfunction of a pressure relief device occurs when a pressure relief device activates above its set pressure, activates above the pressure limits at §§ 192.201(a) or 192.739(b) as applicable, activates at a pressure below the set pressure, or otherwise fails to operate as designed or intended. When a malfunction occurs, an operator must:

(1) Take immediate action to stop the release and restore overpressure protection. Alternative methods used to provide for overpressure protection must be maintained until the pressure relief device is adjusted, repaired, or replaced.

(2) Evaluate the pilot, springs, seats, and other components for proper function, and that the set and reseat pressures are within manufacturer tolerances;

(3) Evaluate the inlet and outlet piping and sensing lines for debris and any other restrictions to the flow of gas;

(4) Evaluate the capacity of the relief device in accordance with § 192.743;

(5) If the malfunction was not discovered during the inspections and tests required by paragraph (a) of this section, conduct the inspections and tests required by paragraph (a) of this section; and

(6) Adjust, repair, or replace the pressure relief device to eliminate the malfunction as soon as practicable.

(d) Records of pressure relief device malfunctions and records pertaining to adjustment, repair, or replacement under this section must be maintained for the life of the device or specific component.

19. Add § 192.760 to read as follows:

§ 192.760 Leak grading and repair.

(a) *General*. Except as provided in paragraph (a)(3), each operator must have and follow written procedures for grading and repairing leaks that meet or exceed the requirements of this section.

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

(2) Each leak must be investigated immediately and a leak grade determination must be made as part of that investigation.

(3) Leaks discovered before January 1, 2028, must be graded, reevaluated, and repaired either in accordance with the requirements of this section or as follows:

(i) Leaks must be graded, repaired, and monitored in accordance with the operator's procedure manual and applicable Federal (including § 192.703(c) existing on **[insert date of publication of the final rule]**) and State requirements existing on **[insert date of publication of the final rule]**, but repair must be completed no later than the maximum repair timelines in paragraphs (a)(3)(ii) and (a)(3)(iii) of this section.

(ii) Leaks with a grade 2 classification, or equivalent moderate priority classification, must be repaired no later than January 1, 2029.

(iii) All other leaks remaining on January 1, 2028, must be reevaluated no later than January 1, 2029. During this reevaluation, the operator must grade the leak in accordance with the requirements of this section. After a grade has been established, the leak must be managed and repaired in accordance with the requirements of this section, unless a shorter repair timeline would have been required by paragraph (a)(3)(i) of this section.

(iv) For the purpose of § 192.760(a)(3)(iii) the date of discovery for defining repair timelines is the reevaluation date.

(b) *Grade 1 leaks*. (1) A grade 1 leak means a leak with any of following characteristics:

(i) Any leak that, in the judgment of operating personnel requires immediate repair;

(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) Any below-grade 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;

(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 and which is in a location that may endanger the general public or property;

(viii) Any leak on a gas transmission or regulated gas gathering line with a measured or calculated leakage rate of 100 kg/hr or more; or

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

(2) An operator must promptly repair a grade 1 leak and eliminate the hazardous conditions caused by the leak by taking immediate and continuous actions 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. Continuous means that the operator must maintain response and repair efforts until the leak repair has been completed, except as provided in paragraph (b)(3). 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.

(3) Continuous action may stop following an attempt at repair but prior to a post-repair recheck in accordance with paragraph (g) provided conditions meeting the definition of a grade 1 listed in paragraph (b)(1) leak no longer exist.

(c) *Grade 2 leaks*. (1) A grade 2 leak means any leak (other than a grade 1 leak) with any 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;

(iv) A reading less than 80% of the LEL in a substructure (other than gas-associated substructures) from which gas could migrate to the outside wall of a building;

(v) A reading of 80% or greater of the LEL in a gas-associated substructure from which gas could not migrate to the outside wall of a building;

(vi) Any leak that occurs on the pipe body (including pipe-to-pipe connections) of a pipeline operating at or above 30% of more of SMYS;

(vii) A leak on a gas transmission line located in an HCA or a gas transmission or regulated gas gathering line, each located in a Class 3 or Class 4 location;

(viii) A leak on a distribution line with a flowrate as determined by any one of the following methods:

(A) A measured or calculated leakage rate of 10 standard cubic feet per hour (SCFH) or more,

(B) For below-grade and subsurface leaks, a measured leak extent of 2,000 square feet or greater. The leak extent is a rectangle containing gas-affected soil. To measure the leak extent area, an operator first establishes the perimeter of ground area affected by gas migration (i.e., with readings greater than zero percent gas) based on measurements taken at ground level. The leak extent is the area of a rectangle that contains the entire perimeter of ground area affected by gas migration. The length and width of the rectangle containing the perimeter of the gas-affected surface must be established at points with zero percent gas readings taken at ground level.

(C) A method determined to be equivalent of a leakage rate of 10 SCFH or more as calculated by an alternative method permitted through advanced notification to and no objection from PHMSA in accordance with § 192.18.

(ix) Is a leak on a transmission line or regulated gas gathering line with a measured or calculated leakage rate exceeding 10 kg/hr.

(x) Any leak of LPG that does not qualify as a grade 1 leak; or

(xi) Any leak that, in the judgment of operating personnel, requires repair within 12 months or less.

(2) Except as provided in paragraphs (c)(3) and (c)(4) of this section, a grade 2 leak must be repaired as soon as practicable but within 12 months of discovery.

(3) A grade 2 leak may be evaluated in accordance with paragraph (c)(5) of this section and repairs postponed if the segment containing the leak is scheduled for replacement, and is replaced, within 24 months of discovery of the leak.

(4) The operator must complete repair of any grade 2 leak on a gas transmission pipeline in an HCA or a gas transmission or Type A gathering line located in a Class 3 or Class 4 location that meets any of the criteria listed in (c)(1)(i) through (c)(1)(vi) or (c)(1)(xi), within 30 days of discovery. If repair cannot be completed within 30 days due to permitting requirements or parts availability, the operator must reevaluate the leak once every 2 weeks and complete repair as soon as practicable.

(5) Except as provided in paragraph (c)(4) of this section an operator must reevaluate each grade 2 leak at least once every 6 months until it is repaired.

(d) *Grade 3 leaks.* (1) A grade 3 leak means 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;

(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.

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

(i) A grade 3 leak may be reevaluated 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 84 months of discovery of the leak.

(ii) Except for leaks downgraded in accordance with paragraph (i)(1) of this section, reevaluation in accordance with paragraph (d)(3) of this section until the leak is eliminated per paragraph (g)(2) of this section without repair may occur for grade 3 leaks that meet any of the following characteristics:

(A) A grade 3 leak with a measured or calculated emissions rate of less than 5 SCFH, or

(B) A below-grade or subsurface grade 3 leak on a pipeline operating at less than 20% of SMYS with a measured leak extent area of less than 1800 square feet using the methodology described in paragraph (c)(1)(viii)(B) of this section; or

(C) A grade 3 leak determined by an alternative method to be equivalent to a measured or calculated emissions rate of less than 5 SCFH permitted with advanced notification and no objection from PHMSA in accordance with § 192.18.

(3) Each operator must reevaluate each grade 3 leak at an interval not to exceed 12 months until repair of the leak is complete.

(e) *Repair Scheduling.* Each operator's operation and maintenance procedures must include a methodology for prioritizing, within each grade, the repair of grade 2 and grade 3 leaks based on the potential impacts to persons, property, and the environment. The methodology must include an analysis of, at a minimum, each of the following parameters:

(1) The volume and migration of gas emissions;

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

(3) The extent of pavement;

(4) Soil type and conditions, such as frost cap, moisture, and natural venting; and

(5) Scheduling with other planned shutdowns, maintenance, and repairs.

(f) *Reevaluation following environmental changes.* Each operator must reevaluate a known, below ground grade 2 or grade 3 leak when the operator becomes aware of any changes in the environment near the existing leak, such as freezing ground, heavy rain, flooding, or new pavement, that may affect the venting or migration of gas and could allow gas to migrate to the outside wall of a building. The operator must upgrade the leak to a higher-priority grade in accordance with paragraph (h) of this section if the reevaluation finds that the leak meets the criteria of the higher-priority grade. This reevaluation may be made in the course of an operator's written program to evaluate weather-related impacts to its system.

(g) *Post-repair recheck.* (1) A leak repair is considered eliminated after successful completion of a permanent repair. An operator must recheck a leak repair in accordance with this section in order to eliminate a leak and consider the permanent repair complete. A recheck is not required for leaks eliminated by:

(i) Routine maintenance work—such as adjustment or lubrication of above-ground valves, or tightening of packing nuts on valves with seal leaks.

(ii) Replacement or permanent abandonment of the leaking pipeline in accordance with § 192.727.

(2) When a recheck is performed, a leak is considered eliminated when the operator obtains a gas concentration reading of less than 1% LEL (500 ppm for natural gas) at the leak location after a permanent repair during a recheck performed in accordance with this section

(3) A recheck must be performed at least 14 days after the attempted repair, unless the operator is able to determine that the soil has adequately vented and stabilized, in which case the recheck may be performed sooner. In either case the recheck may not be performed more than 30 calendar days after repair.

(4) A recheck may be performed immediately following the attempted repair in the following circumstances as an exception to paragraph (g)(3) above for:

(i) A repair on an aboveground or submerged pipeline facility, or

(ii) A repair of grade 3 leaks, or

(iii) A repair of a leak caused by excavation damage where the extent of the damage is known.

(5) If a post-repair recheck shows a gas concentration reading greater than or equal to 1 percent LEL (500 ppm for natural gas), the operator must perform a follow-up recheck within 30 days and then take the following actions until the leak is eliminated:

(i) If a subsequent recheck shows a gas concentration lower than the most recent previous, recheck reading, the operator must perform a subsequent recheck within 30 days and continue rechecking at least once every 30 days after each recheck thereafter until there is a gas concentration reading of less than 1 percent LEL (500 ppm for natural gas).

(ii) If a subsequent recheck shows a gas concentration equal to or higher than the previous, most recent reading, the operator must investigate the repair to determine the source of the leakage and correct the repair. The operator must upgrade the leak to a higher-priority grade in accordance with paragraph (h) of this section if, during the investigation, the operator finds the leak meets the criteria of the higher-priority grade.

(h) *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.

(i) *Downgrading leak grades.* The required repair timeline for a downgraded leak is the remaining time allowed for repair under its new grade measured from the time the leak was detected. A leak may not be downgraded to a lower-priority leak grade unless:

(1) A temporary repair to the pipeline has been made or a permanent repair was attempted but gas was detected during the post-repair recheck under paragraph (g) of this section. A leak downgraded under this provision is not eligible from repair exception under paragraph (d)(2)(ii). or

(2) The leak was initially graded incorrectly based on information available at the time the initial grade determination was made.

(j) *Recordkeeping.* (1) Records documenting the grading, reevaluation, rechecks, upgrades, and downgrades of leaks in accordance with this section must be retained for 5 years after the final post-repair recheck is completed under paragraph (g) of this section.

(2) Records of the date, location, and description of the leak repair or remediation made in accordance with this section must be made and retained for the life of the pipeline unless, for gas transmission and regulated gas gathering lines, a different interval is specified in § 192.709.

20. Add § 192.763 to read as follows:

§ 192.763 Advanced Leak Detection Program.

(a) *Advanced Leak Detection Program (ALDP) elements.* Except as provided in paragraph (e) of this section, each operator of a gas pipeline facility must have and follow a written ALDP that includes the following elements:

(1) *Leak detection equipment.* The ALDP must include a list of leak detection equipment used in operator leakage surveys (including screening surveys) and for pinpointing and investigating leaks. Leak detection equipment must be validated by the operator or manufacturer to meet the performance standard in paragraph (b) of this section applicable to the equipment and intended use.

(2) *Leak detection procedures.* The ALDP must include written procedures for:

(i) *Performing leakage surveys*. Operators must have procedures for performing leakage surveys required in accordance with §§ 192.9, 192.706 and 192.723 applicable to the facility using each selected leak detection technology as described at paragraph § 192.763(a)(1). The procedures must define environmental and operational conditions for which each leak detection technology is and is not permissible. At a minimum, environmental conditions must include wind speed, ambient temperature, humidity, and weather-related factors that affect detection or gas migration such as rain, frost, snow, and ice. Operational parameters must include the types of facilities for which the survey method is and is not effective, the effective range of the survey method, and minimum dwell time or maximum survey speed (for aerial and mobile surveys) necessary for a reliable reading. The operator's procedures must follow the leak detection equipment manufacturer's instructions for survey methods and allowable environmental and operational parameters.

(ii) *Pinpointing leaks.* The location of the source of each indication of a leak found during a leakage survey, including all screening surveys, must be pinpointed with a method meeting the requirements at paragraph (b)(4) of this section.

(iii) S*creening surveys:*_A screening survey is a type of leakage survey performed using infrared or laser-based leak detection equipment; mobile, aerial, or satellite-based platforms; or using fixed continuous monitoring sensors to identify indications of leaks meeting the applicable criteria defined at paragraph (b) of this section for follow-up investigation. When performing a screening survey, the survey procedure must include follow-up investigation of all discovered indications of leaks in accordance with § 192.763(a)(2)(ii). This procedure must include criteria for prioritizing indications of leaks that considers the potential hazard to public safety and the environment.

(iv) *Maintaining and calibrating leak detection equipment.* Procedures must follow the equipment manufacturer's instructions for calibration and maintenance. Leak detection equipment must be calibrated or replaced following any indication of malfunction. Records of equipment calibration and malfunctions indicating recalibration is necessary must be maintained for 5 years after the date the individual device is no longer used by the operator.

(3) *Periodic evaluation and improvement.* Each operator must evaluate the effectiveness of the ALDP and make changes to the ALDP, as necessary, based on the results of that evaluation at least once every 3 calendar years, with an interval between evaluations not exceeding 39 months.

(i) The operator must make changes to any program element necessary to locate and eliminate leaks in accordance with this section and § 192.760. When determining necessary changes to program elements, operators must analyze, at a minimum, the performance of the leak detection equipment used, the adequacy of the leakage survey procedures, any changes on the operator's system in pipeline type, location, pipeline material, or material transported by the pipeline that may affect the performance of leak detection equipment used, 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.

(ii) The operator must implement any changes identified by the program evaluation and maintain documentation of changes for 5 years following the date of the change.

(b) *Advanced leak detection performance standard.* Leak detection equipment listed in the operator's ALDP in paragraph (a)(1) of this section must have a minimum detection performance as follows:

(1) For leakage surveys of gas transmission and regulated gas gathering lines the following standards apply:

(i) Leakage surveys performed with a screening survey using infrared or laser-based leak detection equipment; mobile, aerial, or satellite-based platforms; or using fixed continuous monitoring sensors must have a minimum flowrate detection limit of 10 kg/hr with a 90 percent probability of detection. The source of each indication of a leak above that value must be located in accordance with paragraph (a)(2)(ii) with handheld equipment meeting the requirements provided at paragraph (b)(4).

(ii) Equipment used for leakage surveys performed with handheld leak detection equipment must have a minimum sensitivity of 5 ppm or 5ppm-m except as provided at paragraph (b)(3) of this section.

(iii) Equipment for leakage surveys with leak detection equipment mounted on ground vehicles must have a minimum sensitivity of 5 ppm or 5 ppm-m. The survey must be performed within the effective range of detection and at a speed no greater than the maximum survey speed defined in the operators' procedures required by paragraph (a)(2) of this section. For mobile surveys using the 5-ppm sensitivity standard, the intakes for gas measurement equipment must be located as near as practicable to the pipeline facility. The source of each indication of a leak must be located in accordance with paragraph (a)(2)(ii) of this section with handheld equipment meeting the requirements provided at paragraph (b)(4) of this section.

(2) For leakage surveys of gas distribution lines, the following standards apply:

(i) Leakage surveys performed with screening surveys using infrared or laser-based leak detection equipment; mobile, aerial, or satellite-based platforms; or using fixed continuous monitoring sensors must have a minimum flowrate detection limit of 0.2 kg/hr with a 90% probability of detection. The source of each indication of a leak above that value must be located in accordance with paragraph (a)(2)(ii) of this section with handheld equipment meeting the requirements provided at paragraph (b)(4) of this section.

(ii) Equipment used for leakage surveys performed with handheld leak detection equipment must have a minimum sensitivity of 5 ppm or 5ppm-m except as provided at paragraph (b)(3) of this section.

(iii) Equipment for leakage surveys with leak detection equipment mounted on ground vehicles must have a minimum sensitivity of 5 ppm or 5 ppm-m. The survey must be performed within the effective range of detection and at a speed no greater than the maximum survey speed defined in the operators' procedures required by paragraph (a)(2) of this section. For mobile surveys using the 5-ppm sensitivity standard, the intakes for gas measurement equipment must be located as near as practicable to the pipeline facility. The source of each leak indication above that value must be located in accordance with paragraph (a)(2)(ii) with handheld equipment meeting the requirements provided at paragraph (b)(4).

(3) For leakage surveys of non-buried appurtenances and pipelines located inside of buildings the following standards apply:

(i) Equipment used for leakage surveys with handheld equipment must have a minimum sensitivity of 1% LEL (500 PPM for methane gas).

(ii) A leakage survey may be performed by applying a soap solution (or an equivalent fluid capable of conspicuously visualizing leaks) directly to the pipeline.

(iii) Fixed continuous monitoring equipment with a minimum sensitivity of 500 ppm or 500 ppm-m may be used to perform leakage surveys of facilities within the effective range of the device defined in the operators' procedures required by paragraph (a)(2) of this section. The source of each leak indication must be located in accordance with paragraph (a)(2)(ii) with handheld equipment meeting the requirements provided at paragraph (b)(4).

(iv) For gas transmission and regulated gas gathering lines, a non-optical continuous monitoring system (e.g., acoustical or pressure monitoring systems) may be used to meet the requirements for performing a leakage survey. The system must meet the performance requirements at paragraph(b)(1)(i) or (d) of this section. The source of each indication of a leak must be located in accordance with paragraph (a)(2)(ii) with handheld equipment meeting the requirements provided at paragraph (b)(4).

(v) Except for gas distribution service lines, including customer meter assemblies, leakage surveys of aboveground facilities may be performed with optical gas imaging equipment and procedures meeting the requirements of Appendix K of 40 CFR part 60.

(4) Pinpointing the source of an indication of a leak under paragraph (a)(2)(ii) must be performed with one of the following methods:

(A) Using handheld equipment located as near as possible to the source of the leak facility with a minimum sensitivity of 5 ppm, or 5 ppm-m, except that handheld equipment with a minimum sensitivity of 1% LEL (500 ppm for methane) may be used for indications of leaks on non-buried pipelines and pipelines located inside of buildings.

(B) Applying a soap solution (or an equivalent fluid capable of conspicuously visualizing the source of leaks) directly to the pipeline to locate the leak visually (e.g., soap bubbles).

(C) For indications of leaks on pipelines submerged below the waterline, leaks may be located visually.

(c) *Qualifying leakage survey equipment.* An operator must qualify each type of leak detection equipment listed in the ALDP by doing the following:

(1) An operator must validate that each model or type of leak detection equipment meets the applicable performance standard in accordance with paragraph (b) of this section for the type of device and its intended use by testing with a known concentration or amount of gas at least once prior to first use of each type of leak detection equipment, or maintaining documentation that the performance of the leak detection equipment was validated by the manufacturer; and

(2) Records validating that each model of leak detection equipment meets the applicable performance standard(s) must be maintained for at least 5 years after the date that model is no longer listed in an operator's ALDP.

(d) *Alternative advanced leak detection performance standard.* An operator may use equipment with an alternative ALDP performance standard (and supporting procedures) 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) of this section. 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-increasing conditions, such as increased survey frequency and measures to address risks to public safety from leaks in class 3 and class 4 locations, if applicable;

(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.

(e) *Exception.* The requirements of this section do not apply to a pipeline transporting gas containing more than 50 percent of hydrogen gas by volume.

21. Add § 192.770 to read as follows:

§ 192.770 Gas transmission pipeline blowdowns.

(a) Except as provided in paragraph (c) of this section, when an operator performs any~~,~~ intentional release of gas (including blowdowns or venting for scheduled repairs, construction, operations, or maintenance) from a gas transmission pipeline, the operator must use one or more of the following methods to minimize releases of gas:

(1) Installing control or shutoff fittings to minimize the length of the isolated pipeline segment that needs to be vented to complete the task;

(2) Routing gas released from the pipeline to other equipment as fuel gas;

(3) Reducing pressure by use of in-line 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;

(6) Employing an alternative method demonstrated to result in an emissions reduction of at least 50 percent compared to releasing gas to the atmosphere without minimization; or

(7) Subject to the limitations in paragraph (b) of this section, routing gas released from the pipeline from the nearest isolation valve to a flare.

(b) Sole use of flaring is only permitted when the other options listed in (a)(1) through (a)(5) are impracticable, unsafe, or are calculated to result in higher carbon dioxide equivalent (CO_2 equivalent) emissions than the emissions from flaring.

(c) An operator is not required to comply with the requirements of paragraphs (a) and (b) of this section as follows:

(1) If the original intentional release volume is calculated to be less than 0.5 MMCF;

(2) During an event where such minimization would delay emergency response actions under § 192.615(a)(3);

(3) A release necessary to test an emergency shutdown system per § 192.167;

(4) A release necessary to respond to an immediate repair condition per §§ 192.714(d)(1) and 192.933(d)(1) or grade 1 leak per § 192.760; or

(5) When minimizing the release of gas in accordance with this section would lead to a substantial negative impact to customers' health or safety due to a prolonged loss of gas supply. Operators must provide notification to PHMSA and the appropriate State authority as early as practicable after the release in accordance with §§ 192.18(a) and (b) with justification for the exception. Justification must include, at a minimum, a description of actual or anticipated negative impacts to customers and evidence that providing an alternative supply of gas or minimizing the duration of an outage was not possible.

(d) Records required by this paragraph must be maintained for 5 years after the end of the release and must include:

(1) Documentation of the release and the method or methods used in paragraph (a) of this section to minimize the release of gas.

(2) Documentation of the justification and calculations supporting the use of either the sole use of flaring method in paragraphs (a)(7) and (b) or the alternative method in

paragraph (a)(6). If applicable, when calculating carbon dioxide equivalent emissions, the operator must assume that the carbon dioxide equivalent mass of methane is at least 25 times the mass of carbon dioxide.

(3) If a release is conducted without minimization under paragraph (c) of this section, documentation of the release and the justification to perform the release without minimization.

22. In § 192.1007, republish the introductory text to paragraph (e) and revise paragraphs (e)(1)(i) and (v) as follows:

§ 192.1007 What are the required elements of an integrity management plan?

* * * * *

(e) Measure performance, monitor results, and evaluate effectiveness.

(1) * * *

(i) Number of hazardous leaks (as defined in § 192.1001) either eliminated or repaired (or total number of leaks if all leaks are repaired when found), categorized by cause;

* * * * *

(v) Number of hazardous leaks either eliminated or repaired (or total number of leaks if all leaks are repaired when found), categorized by material; and

* * * * *

PART 193—LIQUEFIED NATURAL GAS FACILITIES: FEDERAL SAFETY STANDARDS

23. The authority citation for part 193 continues to read as follows:

Authority: 49 U.S.C. 5103, 60102, 60103, 60104, 60108, 60109, 60110, 60113, 60118; and 49 CFR 1.53.

24. In § 193.2019, revise paragraph (a) and add paragraph (c) to read as follows:

§ 193.2019 Mobile and temporary LNG facilities

(a) Except for the requirements of paragraphs (b) and (c) of this section, mobile 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 (incorporated by reference, see § 193.2013).

*   *   *   *   *

(c) Beginning on January 1, 2028, operators of mobile and temporary LNG facilities must perform leakage surveys at least one time within 48 hours of placing the LNG facility in service and address leaks according to the following:

(1) Leakage surveys must meet the requirements in § 192.2624(b), (c), (e), and (f).

(2) Records necessary to demonstrate compliance with subparagraph (1) of this section must be maintained in accordance with § 193.2639(a).

(3) Operators must have and follow written procedures for performing and documenting leakage surveys in accordance with paragraph (c) of this section, including procedures for eliminating leaks that represent an existing or probable hazard to persons, property, and the environment.

25. In § 193.2503, add paragraph (h) to read as follows:

§ 193.2503 Operating procedures.

*   *   *   *   *

(h) Minimizing releases of natural gas and LNG, including but not limited to procedures for minimizing emissions in accordance with § 193.2523.

26. Add § 193.2523 to read as follows:

§ 193.2523 Minimizing emissions from blowdowns and boil-off.

(a) Except as provided in paragraph (c) of this section, an operator performing any intentional release of natural gas or LNG (including blowdowns or venting for scheduled repairs, construction, commissioning, operations, or maintenance, flash, and boil-off) after January 1, 2028, must use one or more of the following methods to minimize releases of natural gas and LNG:

(1) Subject to the limitations in paragraph (b) of this section, routing natural gas or LNG released from the facility to a flare;

(2) Routing natural gas or LNG released from the LNG facility to other equipment for use as fuel gas;

(3) Transferring natural gas or LNG to another pipeline facility, other piping, vessels, storage tank, or LNG facility;

(4) Reducing volume to be released by use of scheduled or seasonal operations; or

(5) Employing an alternative method demonstrated to result in an emissions reduction of at least 50 percent compared to releasing natural gas or LNG directly to the atmosphere without minimization.

(b) Sole use of flaring is only permitted when the other options listed in (a)(2) through (a)(4) are impractical, unsafe, or are calculated to result in higher carbon dioxide equivalent emissions than the emissions from flaring.

(c) An operator is not required to comply with the requirements of paragraphs (a) and (b) of this section as follows:

(1) If the original intentional release volume is calculated to be less than 0.5 MMCF; or

(2) During an event where such minimization would delay emergency response actions under § 193.2509.

(d) Records required by this paragraph must be maintained in accordance with § 193.2521 and must include:

(1) Documentation of the release and the method or methods used in paragraph (a) of this section to minimize the release of natural gas or LNG.

(2) Documentation of the justification and calculations supporting the use of either the sole use of flaring method in paragraphs (a)(1) and (b) or the alternative method in paragraph (a)(5). If applicable, when calculating carbon dioxide equivalent emissions, the operator must assume that the carbon dioxide equivalent mass of methane is at least 25 times the mass of carbon dioxide.

(3) If a release is conducted without minimization under paragraph (c) of this section, documentation of the release and the justification to perform the release without minimization.

27. In § 193.2605, add paragraph (b)(3) to read as follows:

§ 193.2605 Maintenance procedures.

* * * * *

(b) * * *

(3) Procedures for eliminating leaks that represent an existing or probable hazard to public safety, property, or the environment, including but not limited to procedures for performing leakage surveys in accordance with § 193.2624.

* * * * *

28. Add § 193.2624 to read as follows:

§ 193.2624 Leakage surveys.

(a) Beginning January 1, 2028,leakage surveys using leak detection equipment, must be conducted on methane or LNG-containing components in LNG facilities at the frequency identified in Table 1 to § 193.2624.

Table 1 to § 193.2624

Type of LNG facility	Leakage Survey Frequency
- LNG facilities with individual container capacity of less than 264,000 gallons or a total aggregate capacity of less than 1,056,000 gallons - Portions of LNG facilities with continuous methane monitoring	At least one time each calendar year, with a maximum interval between surveys not exceeding 15 months
- All other LNG facilities	At least four times each calendar year, with a maximum interval between surveys not exceeding 4 ½ months

(b) An operator must qualify each leakage survey method and type of leak detection equipment for use in this section by doing the following:

(1) Define environmental and operational conditions for which each leak detection equipment is and is not permissible. At a minimum, environmental conditions include wind speed, ambient temperature, humidity, and weather-related factors that affect detection or gas migration such as rain, frost, snow, and ice. Operational parameters include, at a minimum, the types of components for which the survey method is effective, the effective range of the survey method, and minimum dwell time or maximum survey speed (for aerial and mobile surveys) necessary for a reliable leak detection;

(2) Validate that each type of leak detection equipment meets the applicable performance standard in paragraph (c) of this section by testing with a known concentration or amount of gas at least once prior to first use of each type of leak detection equipment, or maintaining documentation that the performance of the leak detection equipment was validated by the manufacturer; and

(3) Calibrate and maintain leak detection equipment consistent with the equipment manufacturer's instructions. Leak detection equipment must be recalibrated according to the equipment manufacturer's instructions or replaced following any indication of malfunction.

(c) Leak detection equipment must have a minimum sensitivity of 5 parts per million or 5 parts per million-meter, except as follows:

(1) Leak detection equipment used for screening leakage surveys or fixed continuous monitoring sensors must have a minimum flowrate detection limit of 10 kg/hour with a 90 percent probability of detection; or

(2) Leak detection equipment used for pinpointing the source of leak indications for components that are not buried, unsafe-to-monitor, or difficult-to-monitor may have a minimum sensitivity of 1 percent LEL (500 parts per million of methane).

(d) Operators must review the results of the leakage surveys and address any natural gas or LNG leaks, safety-related conditions, and abnormal operating conditions. This review must include prioritizing the elimination of leaks based on potential impacts to persons, property, and the environment.

(e) Compliance with the leakage survey calibration, validation, and leak detection equipment capability requirements in paragraphs (b) and (c) of this section is not required if an operator uses either optical gas imaging instruments compliant with Appendix K of 40 CFR part 60, or EPA Method 21 instruments compliant with Appendix A-7 for 40 CFR part 60.

(f) Compliance with the leakage survey frequencies in paragraph (a), and the requirements of paragraphs (b) through (d) of this section is not required for those components or portions of LNG facilities subject to U.S. Environmental Protection Agency (EPA) fugitive methane emission monitoring and repair requirements as follows:

(1) 40 CFR 60.5397a (including alternative means approved through the process described by the EPA under 40 CFR 60.5398a or 60.5399a), or 40 CFR 60.5397b (including

alternative test methods approved under 60.5398b and alternative means approved through the process described by the EPA under 40 CFR 60.5399b); or

(2) An EPA-approved State plan, Tribal plan, or Federal plan which includes methane emissions monitoring and repair standards equivalent to the model standards in 40 CFR 60.5397c (including alternatives approved according to 40 CFR 60.5398c).

29. In § 193.2639, add paragraph (d) as follows:

§ 193.2639 Maintenance records.

* * * * *

(d) The records required by paragraph (a) of this section for leakage surveys performed pursuant to § 193.2624 must include documentation of: leakage surveys, validation tests, calibrations, maintenance, how the operator addressed any leaks, safety-related conditions, or abnormal operating conditions, and if applicable, documentation that components or portions of the LNG facility are covered either by EPA-issued, or EPA-approved, emissions monitoring standards described in § 193.2624(f)(1) or (2).

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