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

Pipeline Safety: Mandatory Regulatory Reviews To Unleash American Energy and Improve Government Efficiency	Docket No. PHMSA–2025–0050

COMMENTS IN RESPONSE TO MANDATORY REGULATORY REVIEWS TO UNLEASH AMERICAN ENERGY AND IMPROVE GOVERNMENT EFFICIENCY ADVANCE NOTICE OF PROPOSED RULEMAKING

FILED BY
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I. Introduction

The Interstate Natural Gas Association of America (INGAA)[1] and GPA Midstream Association (GPA),[2] collectively, the Associations, respectfully submit these comments in response to the Pipeline and Hazardous Materials Safety Administration's (PHMSA or the Agency) "Mandatory Regulatory Reviews To Unleash American Energy and Improve Government Efficiency" Advance Notice of Proposed Rulemaking (ANPRM).[3] In the ANPRM, PHMSA solicits stakeholder feedback on whether to repeal or amend certain requirements in the Pipeline Safety Regulations (PSR) to eliminate undue burdens on the identification, development, and use of domestic energy resources and to improve government efficiency.

The Associations appreciate the opportunity to comment on this ANPRM. In addition to direct responses to PHMSA's specific questions listed in the ANPRM, the Associations also reference their comments filed in response to the U.S. Department of Transportation's Request for Information on May 5, 2025[4] and the Advance Notice of Proposed Rulemaking for Liquefied Natural Gas Facilities Amendments (the LNG ANPRM).[5] Where possible, the Associations have quantified costs and benefits on potential improvements and updates to the PSR. In some cases, it is not possible to quantify costs at this early stage, but the Associations may provide more detailed cost estimates in response to any proposed rules on these topics.

[1] INGAA is a trade association that advocates regulatory and legislative positions of importance to the interstate natural gas pipeline industry in North America. INGAA is comprised of 29 members, representing the vast majority of the U.S. interstate natural gas transmission pipeline companies. INGAA's members operate nearly 200,000 miles of pipelines.

[2] GPA has served the U.S. energy industry since 1921. GPA is composed of over 50 corporate members that directly employ over 57,000 employees that are engaged in the gathering, transportation, processing, treating, storage and marketing of natural gas, natural gas liquids (NGLs), crude oil, and refined products, commonly referred to in the industry as "midstream activities." In 2023, GPA members operated over 506,000 miles of pipelines, gathered over 91 Bcf/d of natural gas, and produced over 5.3 million barrels/day of NGLs from over 365 natural gas processing facilities.

[3] Pipeline Safety: Mandatory Regulatory Reviews to Unleash American Energy and Improve Government Efficiency, 90 Fed. Reg. 23,660 (June 4, 2025).

[4] INGAA Comments in Response to DOT RFI, https://www.regulations.gov/comment/DOT-OST-2025-0026-0872 (May 5, 2025) *See also,* Comments of GPA Midstream Association, Docket No. DOT-OST-2025-0026-0830 (May 5, 2025), https://www.regulations.gov/comment/DOT-OST-2025-0026-0830.

[5] Comments of the American Petroleum Institute, Center for LNG, Interstate Natural Gas Association of America, American Gas Association, American Public Gas Association, and Northeast Gas Association, Pipeline Safety: Amendments to Liquefied Natural Gas Facilities, https://www.regulations.gov/comment/PHMSA-2019-0091-7611, (July 7, 2025); *See also,* Comments of GPA Midstream Association, Docket No. PHMSA-2019-0091-7547 (Jul. 3, 2025), https://www.regulations.gov/comment/PHMSA-2019-0091-7547.

II. Executive Summary

The Associations have reviewed Parts 190, 191, 192, 193, and 199, as well as certain interpretation letters and guidance documents and have identified the following topics as priorities for regulatory reform:

- Class location and clustering
- MAOP reconfirmation process including use of engineering critical assessments and clarifications on section 192.624
- Pre-1970 pressure tests
- Special permit renewals
- Preemption of state regulations
- Inspection process and timing
- Reporting requirements
- Repair criteria
- Risk-based LNG facilities
- Limiting facility integrity assessments to line pipe
- Thermal relief device inspection requirements

The Associations discuss some of these priorities at length in its comments in response to the DOT RFI,[6] Repair Criteria ANPRM,[7] and LNG ANPRM.[8] This document is an extension of the Associations' comments to those rulemakings.

III. Detailed Comments

A. Topic Area: Procedural Regulations and Actions

A.1. Retrospective Regulatory Reviews

Should PHMSA consider incorporating within its PSR an explicit requirement to conduct retrospective regulatory reviews at specified intervals to eliminate undue burdens and improve government efficiency? Please identify any specific regulatory language would be appropriate for

[6] INGAA Comments in Response to DOT RFI, https://www.regulations.gov/comment/DOT-OST-2025-0026-0872 (May 5, 2025).
[7] Comments of Interstate Natural Gas Association of America, GPA Midstream, and the American Gas Association, PHMSA-2025-0019 (July 21, 2025).
[8] Comments of the American Petroleum Institute, Center for LNG, Interstate Natural Gas Association of America, American Gas Association, American Public Gas Association, and Northeast Gas Association, Pipeline Safety: Amendments to Liquefied Natural Gas Facilities, https://www.regulations.gov/comment/PHMSA-2019-0091-7611, (July 7, 2025).

that purpose. What interval would be appropriate? How should PHMSA provide opportunities for stakeholder engagement in those reviews?

PHMSA could incorporate an explicit requirement into Part 190 to conduct retrospective regulatory reviews at specified intervals provided that such efforts do not constrain resources in other areas of PHMSA's important mission. The Associations agree with PHMSA's analysis in the ANPRM citing the previous directives to conduct similar reviews.[9] In addition to these orders, the Administrative Conference of the United States (ACUS) has recommended that federal agencies undertake periodic regulatory reviews since at least 1995.[10] Pipeline safety regulations are ripe for regulatory reviews at set intervals given the rapidly changing scientific and technological environment in which pipeline facilities operate. This ever-changing environment has been heightened by artificial intelligence innovation and modernization. PHMSA should focus the scope of such a review on aligning regulations with current industry practices, emerging technologies, and eliminating undue burdens without compromising safety standards.

The Associations also support PHMSA's notion that it would be useful to conduct a comprehensive retrospective cost-benefit review. As PHMSA acknowledges in the ANPRM, the regulations in Parts 192 and 193 have been in place for decades.[11] If PHMSA truly seeks to eliminate undue burdens and improve government efficiencies, a retrospective cost-benefit analysis is paramount. Given that the scope of authority for the technical safety standards committees includes risk assessment and cost-benefit analyses,[12] PHMSA should use its Gas Pipeline and Liquid Pipeline Advisory Committees to inform the regulatory review. PHMSA should also leverage the LNG Center of Excellence regarding operational innovations, emerging technologies identified through the Competitive Academic Agreement Program (CAAP) or other Research and Development programs, and updated editions of consensus codes and standards incorporated by reference that reflect current industry best practices.

A comprehensive regulatory review at regular intervals may ensure that regulatory obligations and their associated costs continue to be justified by their safety benefits and that requirements which are outdated, duplicative or unnecessarily burdensome are reconsidered. The Associations recommend a seven or ten-year interval, which strikes the appropriate balance between the efficient use of finite agency resources and regular updates to identify outdated regulation that impose unnecessary, outsized, or duplicative compliance burdens. This interval aligns with and builds upon section 610 of the Regulatory Flexibility Act, which mandates reviews of rules with significant economic impact every ten years.

The Associations note that PHMSA could add a retrospective review requirement to Part 190 by creating section 190.345 if such a requirement would not detract from other agency priorities. The Associations provide the following regulatory text:

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[9] 90 Fed. Reg. 23,660 at 23,661-23,662.
[10] *See* ACUS Recommendation 95-3 (June 15, 1995).
[11] 49 Fed. Reg. 23,660 at 23,661-23,662.
[12] 49 U.S.C. § 60115.

§ 190.345 Periodic Regulatory Review

(a) PHMSA shall conduct a review of its pipeline safety regulations at 49 CFR Parts 190-199 every seven to ten years to assess their continued necessity, effectiveness, and efficiency.

(b) Each review shall:

(i) Evaluate the continued technical feasibility, reasonableness, cost-effectiveness, and practicability of PHMSA regulations;

(ii) Consider technological advancements and industry standards and best practices; and

(iii) Solicit and consider stakeholder input, including from technical pipeline safety standards committees established pursuant to 49 U.S.C. § 60115.

(c) PHMSA shall publish a summary of findings and proposed actions in the Federal Register and on its website.

A.2. State Oversight Programs and Interagency Coordination

Can PHMSA eliminate undue burdens or improve government efficiency by taking any actions with respect to its oversight of State authorities or involvement with other Federal agencies? Please identify specific actions that PHMSA should consider for this purpose.

1. Oversight of State Authorities

The lack of understanding by state agencies of federal preemption requirements represents an ongoing undue burden for pipeline operators, particularly for those that operate interstate underground natural gas storage facilities. As PHMSA is aware, in order to promote the Agency's interest in administering an effective federal program, the Pipeline Safety Act contains a preemption provision in 49 U.S.C. § 60104(c) that limits the ability of state authorities to apply safety standards to interstate pipelines facilities.[13] Section 60104(c) states, in relevant part, that a "State authority may not adopt or continue in force safety standards for interstate pipeline facilities or interstate pipeline transportation[,]" except with respect to administering one-call notification (or damage prevention) programs that meet certain statutory requirements.[14] For intrastate pipeline facilities, a certified state authority may only regulate intrastate pipelines and impose safety requirements in addition to the minimum federal standards if (1) the state authority has a current certification pursuant to § 60105 and (2) the additional safety standard is compatible with the federal standards.[15]

[13] 49 U.S.C. § 60104(c).
[14] *Id.* (emphasis added).
[15] 49 U.S.C. § 60105.

The Associations' members often experience certified state authorities attempting to regulate interstate facilities or non-certified state authorities scheduling inspections of intrastate facilities. Neither approach is allowed under federal law.[16]

PHMSA has acknowledged via interpretation the key questions to determining whether state regulation of an intrastate pipeline facility is preempted.[17] In a letter issued to the Pennsylvania Public Utility Commission, PHMSA offered a roadmap for whether a state regulation was preempted.[18] However, it might be useful for PHMSA to produce more extensive guidance on this question. The Associations also ask PHMSA to consider codifying a process similar to the Office of Hazardous Materials' approach to resolving preemption questions.[19]

2. Cross-Coordination with Other Federal Agencies

PHMSA can significantly eliminate undue burdens and improve government efficiency by implementing coordinated inspection protocols and establishing clear communication mechanisms with other federal agencies. Operators currently face separate inspections from multiple federal agencies which often examine identical compliance topics, often with inconsistent findings. PHMSA should work with the U.S. Department of Energy (DOE), the U.S. Department of Interior's Bureau of Safety and Environmental Enforcement (BSEE), and the Federal Energy Regulatory Commission (FERC) to develop coordinated inspection protocols that eliminate duplicative oversight while ensuring comprehensive safety coverage.

U.S. Department of Interior

PHMSA has created a new offshore group which has duplicated efforts by operators to satisfy both BSEE and PHMSA. PHMSA should work with BSEE to develop coordinated requirements and inspection protocols that eliminate duplication while ensuring safety. Agencies should coordinate among themselves to reduce redundancy of inspections and unannounced drills.

U.S. Department of Energy

PHMSA should also coordinate with DOE to require electrical transmission operators to share project information and electrical load information, to the extent possible, to allow for pipeline operators to properly design for the increased current on the electrical transmission lines to meet the requirements of section 192.473. The pipeline industry has recently learned of a process that is called reconductoring. This allows an electric provider to install new powerlines that allow for increased current but has minimal ground disturbance. This is extremely difficult for pipeline

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[16] Section 60104(c) has been broadly construed by the federal courts. *ANR Pipeline Co. v. Iowa State Commerce Comm'n*, 828 F.2d 465 (8th Cir. 1987) (ruling that state authority could not adopt and apply PHMSA's pipeline safety standards to an interstate gas pipeline facility); *Natural Gas Pipeline Co. of America v. R.R. Comm'n of Tex.*, 679 F.2d 51 (5th Cir. 1982) (ruling that state authority's safety rules for pipelines containing hydrogen sulfide could not be applied to an interstate gas pipeline facility); *Colo. Interstate Gas Co. v. Wright*, 707 F.Supp.2d 1169 (D. Kan. 2010) (ruling that state authority could not apply its safety standards for underground natural gas storage fields to an interstate gas pipeline facility).
[17] Letter of Interpretation to Adam Young, PI-23-0008 (Mar. 22, 2023).
[18] *Id.*
[19] *See* 49 CFR Part 107.

operators to know the increased capacity has been installed since there are no or limited permits filed and miles of powerline that can be installed per day. In addition, some electrical operators do not share current information for pipeline operators to use for alternating current (AC) mitigation design purposes.

Federal Energy Regulatory Commission

As discussed in detail in INGAA's LNG comments,[20] large-scale LNG facilities face inspections from both PHMSA and FERC during the design and construction inspections, sometimes reviewing identical documentation at separate times, requiring operators to produce similar records multiple times within the same 12-week period. This duplicative approach strains federal government resources and imposes unnecessary burdens on operators who must dedicate subject-matter expert staff to accommodate multiple inspection teams without a commensurate safety benefit. For large-scale LNG facilities, a single construction inspection requires approximately $149,400 in personnel costs monthly, with additional specialized walkdowns costing $101,200 per request. Operations inspections can cost approximately $365,000 for preparation and attendance, while comprehensive pipeline inspections can exceed $2.3 million in personnel costs.

U.S. Coast Guard

PHMSA should establish the U.S. Coast Guard as the primary agency for security requirements for waterfront liquefied natural gas facilities subject to 33 CFR § 105 and 33 CFR § 127 regulations.

A.3. Reducing Disproportionate Impact on Small Businesses

What number of small businesses, small organizations, or small government jurisdictions, as defined in the Regulatory Flexibility Act (5 U.S.C. 6010 et seq.) and its implementing regulations, operate different categories of PHMSA-jurisdictional gas, hazardous liquid, and carbon dioxide pipeline facilities? Please provide information about the nature and types of activities of small businesses and other small entities operating in midstream gas, hazardous liquid, and carbon dioxide pipeline sectors. Are there any existing PSR requirements that disproportionately impact small businesses or other small entities in the sector? Are there alternative regulatory approaches the agency should consider that would achieve its regulatory objectives while minimizing any significant economic impact on small businesses or other small entities?

Operators of gas transmission and gathering pipeline segments along the energy supply chain are comprised of large and small companies, and there should be appropriate, right-sized regulations that are suitable for both. For smaller companies, as defined in the Regulatory Flexibility Act, these regulations should accommodate the fact that they may not have many in-house regulatory, engineering, or compliance resources. Smaller companies often rely on third-party contractors for specialized services. Because smaller companies lack economies of scale, they can incur higher per-mile compliance costs. Lower staffing levels also could make short compliance timeframes

[20] Comments of the American Petroleum Institute, Center for LNG, Interstate Natural Gas Association of America, American Gas Association, American Public Gas Association, and Northeast Gas Association, Pipeline Safety: Amendments to Liquefied Natural Gas Facilities, PHMSA-2019-0091-7611, (July 7, 2025).

challenging. In addition, as staffing is supplemented by contractors, the availability of these resources might be limited across industry, if many operators require the same contractors' expertise, tools, and processes.

The comments made by the Associations in this document, as well as their responses to the DOT RFI and Repair Criteria ANPRM, are applicable to both large and small operations; however, the following items would be of particular benefit to small operators.

The section 192.18 notification process referenced in many portions of the regulation, the special permit process, and the engineering critical assessment (ECA) used for reconfirmation of maximum allowable operating pressure are very challenging for small operators to use. These are time consuming processes and require many technical resources to implement and respond to PHMSA questions. Additionally, the unknown timing of PHMSA responses on section 192.18 submissions and special permits makes it even more challenging for a small business to absorb in its work planning and expenses.

For section 192.18 notifications, the Associations request that PHMSA reduce the number of 192.18 notifications required and provide a final answer to the 192.18 request within 90 days, or if additional time is needed, limit the review to one additional 30-day extension.[21] This timing would provide certainty for operators as they manage their work planning and expenses.

The current ECA process could be a benefit to small operators since it could be more cost efficient and minimize downtime of a pipeline. However, PHMSA would need to modify the process. The Associations request that PHMSA allow operators to utilize the ECA process, as defined in section 192.632, as a one-time assessment that confirms there is not a detrimental manufacturing or construction defect that is injurious to the pipe.

In addition, PHMSA should allow operators to make risk-based decisions, allowing for flexibility in remediation timelines. Industry standards could be adopted and provide for performance-based practices that account for the diverse pipeline operating parameters and risk profiles. The Associations discuss those industry standards in their comments on PHMSA's Repair Criteria ANPRM.

Finally, as discussed in response to Question A.4, the Associations request specific application requirements, a more timely review of special permit requests, and modified conditions tailored to the regulation subject to the permit. These changes would encourage small operators to use the special permit process.

A.4. Special Permits

Do PHMSA's regulations, implementing guidance, or practices governing special permits (49 CFR 190.341) impose an undue burden on affected stakeholders? Please identify any specific amendments to regulations, guidance, or protocols meriting consideration, as well as the technical, safety, and economic reasons supporting those actions.

[21] *See* Response to Question B.4 (Reporting and Notifications).

The special permit process serves a critical function in allowing operators to demonstrate alternative compliance approaches that maintain or enhance safety while addressing unique operational circumstances. However, the current process suffers from several procedural inefficiencies that create undue burdens and may inadvertently discourage operators from pursuing innovative safety solutions. Often the lack of clear, standardized expectations leads to repeated follow-up requests and delays that consume both operator and PHMSA resources while extending timelines and slowing innovation.

The Associations recognize that in recent months, PHMSA has made significant improvements to the special permit review and approval process. The Agency is more proactive in engaging with operators throughout the process, and most notably, has refined special permit conditions by focusing on the subject of the waiver and removing redundant requirements that operators are already obligated to comply with in the PSRs. The Agency has also adopted categorical exclusions for certain special permits which will streamline the environmental assessment process. Finally, PHMSA has proposed changes to section 190.341 to use conditions specific to the regulation that is the subject of the waiver.[22] The Associations applaud these changes. The conditions of the special permit must relate to the risk and regulation for which the operator is seeking a special permit. Together, these efforts will reduce the administrative burden on both PHMSA and operators. While The Associations appreciate and supports these modifications, its members seek three additional changes to the special permit process: (1) clear and consistent application requirements; (2) a predictable review timeframe; and (3) a reasonable renewal timeframe.

Application Requirements

PHMSA should develop and publish standardized application templates and checklists that clearly outline the agency's expectations for technical documentation, risk analysis, environmental considerations, and mitigation measures for different types of special permit requests. These templates should specify the level of detail required for various components of the application, including engineering analysis, safety assessments, environmental review, and proposed monitoring or mitigation measures. The templates should be tailored to different categories of special permits.

Operators must invest significant resources in preparing applications without clear guidance on PHMSA's expectations, often requiring multiple iterations and additional technical studies to address follow-up requests. The most significant burden stems from unclear and inconsistent application requirements, particularly regarding the expected level of detail for environmental analysis, technical documentation, and risk assessment. Operators frequently submit applications that they believe are complete, only to receive requests for additional information that could have been provided initially if PHMSA's expectations were clearly communicated. This iterative process not only delays permit decisions but also creates inefficient use of resources as operators must repeatedly engage technical experts and consultants to address follow-up requests that could have been anticipated with clearer guidance.

[22] Pipeline Safety: Rationalize Special Permit Conditions, 90 Fed. Reg. 28,950 (July 1, 2025).

Defined Review Timeframe

The Associations recommend that PHMSA create a predictable review timeline accounting for application complexity while providing operators with realistic expectations for decision timing. The Associations recommend 9-12 months. The current unpredictable timeline creates additional costs as operators must maintain contingency plans, potentially delay beneficial projects, or implement less optimal compliance approaches while awaiting permit decisions.

PHMSA should implement a transparent tracking system that allows applicants to monitor the status of their special permit applications throughout the review process, providing regular updates on review progress and indicating expected decision timelines.

Renewal timeframe

The time period between when an initial permit is approved by the Agency and prior to the renewal process begins is limited and imposes considerable administrative effort and resource strain on PHMSA and operators.[23] As discussed in its DOT RFI comments, the Associations seek to modify the renewal cycle to 15 years.[24] Extending the renewal cycle to fifteen years would cover two assessment cycles, mitigate the frequency of administrative tasks, provide greater consistency and stability for operators and foster a more stable regulatory environment. It would also enable better long-term planning and investment strategies. Longer renewal cycles can positively impact stakeholders by reducing the frequency of regulatory changes that could affect operations. This stability can lead to enhanced service continuity and reliability for customers and other stakeholders.

INGAA stated in its DOT RFI comments that the time and costs associated with the existing renewal process can be substantial. The Associations now provide additional cost information to support that position. Special permits vary by scope and complexity, and as such, a typical special permit renewal may cost an operator approximately $100,000 including administrative costs for office and field personnel, legal support, and consultant fees. In a recent class location special permit renewal, PHMSA required an updated environmental assessment, environmental justice review, and updated conditions with supporting records, resulting in a cost of $1,000,000 to the operator for a potential 5-year permit renewal. Extending the minimum renewal interval to 15 years would result in cost reduction of approximately $50,000 - $500,000 per permit.

Extending the renewal cycle to fifteen years would reduce this burden.

A.5. NEPA and Categorical Exclusions

Do PHMSA's compliance practices with respect to the National Environmental Policy Act place an undue burden on affected stakeholders? Are there any categorical exclusions that PHMSA should adopt? If so, please identify the activities that should be considered for a categorical exclusion, as well as the technical, safety, and environmental bases for adding those categorical

[23] Operators must file an application for renewal no later than 180 days prior to the expiration date of the permit. *See* 49 CFR § 190.341(e).
[24] INGAA Comments on DOT RFI, DOT-OST-2025-0026, https://www.regulations.gov/comment/DOT-OST-2025-0026-0872 (May 5, 2025) at 16.

exclusions. Are there any categorical exclusions employed by other Federal agencies that PHMSA should adopt pursuant to 42 U.S.C. 4336c?

The Associations recognize that on July 1, 2025, DOT issued its Order 5610.1D (Procedures for Considering Environmental Impacts) which included a list of categorical exclusions (CEs) applicable to certain actions by the Office of Pipeline Safety.[25] The Associations support that decision and agrees that these CEs will streamline the environmental review process. However, The Associations also urge PHMSA to use section 9 of DOT Order 5610.D to avail itself of other agencies' CEs to exempt additional actions. PHMSA's list of CEs and its use in 2024 of the Department of Energy's (DOE) categorical exclusion B5.4 for "repair, replacement, upgrading, rebuilding, or minor relocation of pipelines within existing rights-of-way" represents only a limited step toward addressing the broader categorical exclusion needs for pipeline safety activities.[26]

1. Use of Other Agencies' CEs

PHMSA should expand its list of categorical exclusions to include routine pipeline safety activities such as integrity management assessments, emergency response activities, pipeline safety equipment installation, and maintenance activities that other agencies have categorically excluded. For instance, DOE's categorical exclusions include routine maintenance activities (B1.3), personnel safety and health equipment (B2.3), facility safety and environmental improvements (B2.5), and site characterization and environmental monitoring (B3.1) that are directly analogous to pipeline safety activities. These activities are essential for maintaining the safety and reliability of the nation's pipeline infrastructure and should meet the requirements of categorical exclusions.

2. Developing Additional CEs

PHMSA should consider developing its own CE for three additional actions:

a. Composite Pipe

The Agency and certified state authorities have approved the use of composite pipe such as FlexSteel or Smartpipe through special permits or state waivers to facilitate repair and rehabilitation of aging pipeline systems with minimal environmental impact.

Composite pipe has a proven safety record in both offshore and onshore contexts. A categorical exclusion would be appropriate since there is no significant disturbance to the environment. Pipe

[25] U.S. DOT Order 5610.D (Procedures for Considering Environmental Impacts), https://www.transportation.gov/sites/dot.gov/files/2025-07/DOT_Order_5610.1D_OST-P-250627-001_508_Compliant.pdf (July 1, 2025); The list includes (1) equipment acquisition (including purchase or lease) of handheld and mobile methane detection equipment and associated vehicles; (2) Granting, renewing, or denying a special permit related to waiving class location or odorization requirements, following the procedures set forth in 49 CFR 190.341, including the identification of any enforceable conditions, imposed pursuant to 49 CFR 190.341(d)(2), that are required to prevent and address pipeline safety and environmental risk (3) Rulemaking actions by the Office of Hazardous Materials Safety, other than deregulatory rulemaking actions; (4) Rulemaking actions by the Office of Pipeline Safety, other than deregulatory rulemaking actions; and (5) Repair, rehabilitation, or replacement of natural gas distribution pipelines and associated equipment within existing rights-of-way or easements.

[26] https://www.federalregister.gov/documents/2024/07/03/2024-14652/adoption-of-department-of-energy-categorical-exclusion-under-the-national-environmental-policy-act

is installed by pulling flexible pipe through an existing buried steel pipeline requiring no excavation of the existing pipeline. PHMSA should leverage the NEPA review and analysis performed to date under the existing special permits or waivers that authorize the use of this material.

b. Routine Maintenance

This type of maintenance involves non-invasive work with minimal environmental impact. It enhances pipeline integrity and reduces risk of failure and no significant disturbance to land or ecosystems occurs.

c. Installation of Monitoring Equipment

This type of work involves small-scale installations like sensors or cameras. It is critical work because it can improve real-time monitoring and leak detection efforts. However, there is minimal footprint and no habitat disruption.

A.6. User Fees and Cost Recovery for Design and Construction Reviews

Do annual user fees (49 U.S.C. 60301 et seq.) and charges (e.g., cost recovery pipeline facility design and construction reviews pursuant to 49 CFR part 190, subpart E) imposed by PHMSA place an undue burden on affected stakeholders? If so, please identify specific fees, the regulated entities adversely affected by those fees, and any alternative fee structures meriting consideration.

INGAA seeks improved transparency in the calculation of user fees. Operators have observed fees dramatically changing from year to year without clear explanations for the adjustments, making it extremely difficult for companies to assess the accuracy of the fee and to accurately plan and budget for these regulatory costs.

INGAA recognizes that PHMSA has the statutory authority to assess user fees on gas pipeline transmission facilities, liquefied natural gas pipeline facilities, hazardous liquid pipeline facilities,[27] and underground natural gas storage facilities.[28] Per the statute, PHMSA must prescribe a schedule of fees based on usage "in reasonable relationship to volume-miles, miles, revenues, or a combination of volume-miles, miles, and revenues) of the pipelines."[29] INGAA also acknowledges that PHMSA publishes notices announcing changes in the amount collected.[30] However, INGAA urges the Agency to provide as much detail as possible in these notices explaining the reasoning for the change and how user fees are calculated. INGAA requests that PHMSA provide notice of annual fee increases as early as possible so operators can account for it in their budgetary process. In accordance with the Administrative Procedure Act, PHMSA must ensure that its actions reflect reasoned decision-making.[31] PHMSA is required to "examine the

[27] 49 U.S.C. § 60301(a).
[28] 49 U.S.C. § 60302(a).
[29] 49 U.S.C. § 60301(a).
[30] See https://www.phmsa.dot.gov/operator-resources/notice-liquefied-natural-gas-operators-explanation-fy-2024-user-fee-assessment-increase (Apr. 25, 2024); https://www.phmsa.dot.gov/operator-resources/operator-user-fee-assessment-information (Apr. 4, 2025);
[31] *Motor Vehicle Mfrs. Ass'n v. State Farm Mutual Auto Ins. Co.,* 463 U.S. 29, 43 (1983) (vacating agency's rescission of regulation without adequate explanation).

relevant data and articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'"[32] For these reasons, PHMSA must provide a detailed explanation of its methodology and the criteria it has chosen to calculate user fees and the associated increases.

A.7. Incorporating Interpretations, Approvals, or Special Permits

Are there any interpretations (§ 190.11), approvals (§ 190.9), or special permits (§ 190.341) that should be incorporated into the PSR to eliminate undue burdens or improve government efficiency? Should PHMSA adopt a procedure in the PSR to facilitate the incorporation of similar actions in the future?

1. Incorporating Interpretations and Guidance into the PSRs

Several PHMSA interpretations provide important regulatory clarity that should be incorporated directly into the regulations to ensure consistent application and reduce operator uncertainty. These interpretations have demonstrated their value in providing workable compliance approaches without compromising safety, yet their non-regulatory status creates ongoing uncertainty for operators and inconsistent application across PHMSA regions.

a. MAOP Reconfirmation

Fussell Interpretation

While the Associations understand that the Agency has not yet posted a publicly available response to the Fussell Request for Interpretation, the Associations supports the request[33] and subsequent changes to section 192.624(c). This interpretation request asked PHMSA if there could be additional processes to meet the intent of 192.624(c), while also achieving the 50% requirement by July 3, 2028 and 100% requirement by July 2, 2035.

Any pipeline segment identified prior to July 1, 2021, for MAOP reconfirmation in accordance with § 192.624 should count toward the MAOP reconfirmation mileage threshold requirements specified in § 192.624(b)(2) or § 192.624(b)(3) if any of the following conditions are met.

- A hydrostatic test is conducted in accordance with § 192.506 to establish the MAOP of the pipeline segment;
- Material verification conducted in accordance with § 192.607 to provide TVC records for the pipeline segment MAOP reconfirmation in accordance with § 192.624(a);
- TVC Records are located to support the existing MAOP in accordance with § 192.624(a);
- The pipeline segment is permanently removed from service in accordance with § 192.727;
- The pipeline segment is sold;

[32] *Id.* at 43.

[33] INGAA and GPA Response to Fussell Request for Interpretation dated June 30, 2025.

- The pipeline segment is reclassified from Transmission to Gathering or Distribution;
- The pipeline segment is no longer included in a Class 3 or Class 4 location;
- The pipeline segment is no longer included in a high consequence area;
- The pipeline segment is no longer included in a moderate consequence area; or
- The MAOP of the pipeline segment is reduced to less than 30% of SMYS.

These are actions that operators took to improve pipeline safety. In addition to the direct response to the interpretation, allowing an operator to redefine their transmission pipelines to distribution pipelines should also serve as an allowable method to eliminate the pipe from being included in the section 192.624 requirement.

FAQ-37

PHMSA should also codify FAQ-37 from Batch 1 regarding MAOP reconfirmation under section 192.624, which clarifies that "line pipe and non-line pipe within compressor, meter, and pressure-limiting stations (up to the station emergency shutdown or isolation valves) are subject to § 192.624 and must be incorporated into the operator's MAOP reconfirmation program in draft FAQ-37."[34] This interpretation provides important operational clarity that should be preserved in regulation to prevent future uncertainty.

b. Modeling for LNG Facilities

The Agency should codify its LNG FAQ H6[35] in Part 193 to provide clear regulatory certainty regarding acceptable modeling approaches, eliminating the need for operators to rely on frequently asked questions. Modern modeling tools provide significantly more accurate hazard analysis than the obsolete software currently referenced in regulations. CFD-based modeling tools can account for complex three-dimensional facility geometries, varying terrain conditions, and dynamic atmospheric effects that significantly influence vapor dispersion patterns. This improved accuracy allows operators to design facilities that provide equivalent or enhanced safety performance while optimizing operational efficiency and cost-effectiveness. This request was also covered in the Associations' LNG ANPRM Comments.

c. Scope of Drug and Alcohol Testing Requirements

PHMSA should consider codifying its position in PI-22-0001, PI-90-003, and PI-93-067 that certain administrative or professional work is not a "covered function" pursuant to 49 CFR 199.3.

d. Changes in Original Design Parameters for LNG Facilities

PHMSA should codify its position in PI-0007-2012 that an increase in flow rate is within the original design parameters and is not a significant alternation.[36] Specifically, PHMSA should update 49 CFR 193.2051 to clarify that an increase in flow rate would not be a significant alteration

[34] PHMSA Frequently Asked Questions, No. 37 (Sept. 15, 2020).
[35] PHMSA LNG FAQs, https://www.phmsa.dot.gov/pipeline/liquified-natural-gas/lng-plant-requirements-frequently-asked-questions (last accessed on August 1, 2025).
[36] Letter of Interpretation to William G. Cope, Southern LNG Pipeline Company, PI-007-2012 (Aug. 21, 2012).

and the siting requirements of § 193.2051 and Subpart B of Part 193 would not be triggered. This request was also covered in INGAA's LNG ANPRM Comments.

2. Rescinding Interpretations and Guidance

While PHMSA requested feedback on interpretations and guidance that should be incorporated into the regulations, INGAA has also identified interpretations and guidance documents that should be rescinded or revised.

a. Thermal Relief Valves

On October 4, 2018, PHMSA issued an interpretation to the Michigan Public Service Commission (MPSC) responding to questions about the inspection and testing of relief devices under section 192.731(a). Of note, PHMSA concluded that "[t]he ASME pressure vessel thermal relief valve settings should be based upon the compressor station piping MAOP" and "thermal relief or any redundant relief valves for gas transmission pipelines must be tested and maintained in accordance with applicable § § 192.201, 192.731, 192.739, and 192.743."[37] The Agency also took a broad reading of the word "each" in the regulation and concluded that "all relief devices (overpressure control devices) used for MAOP overpressure control for gas flow, thermal, and redundant purposes in gas carrying transportation pipeline facilities in a compressor station must be installed, maintained and inspected in accordance with the applicable paragraphs of §§ 192.201, 192.731, 192.739, and 192.743."[38]

The interpretation has created a situation that was not the original intent of the code drafters and is fundamentally different from pipeline operations since the implementation of the code. Overpressure protection of the MAOP has typically been recognized at the source of pressure increase (*i.e.,* compressor station or higher-pressure receipt point). The concept that a device not designed to protect the MAOP and is in service for a different design (i.e., protecting maximum allowable working pressure [MAWP]) would then be subject to the testing requirements of an MAOP overpressure protection device is a novel interpretation of the pipeline safety code, specifically §§ 192.619, 192.731, 192.739 and 192.743. Requiring a device designed and installed for MAWP to be converted to an MAOP protection device is contrary to sections 192.153 and 192.165 and may be physically impossible, practically impossible, and provides no additional reduction in safety risk to warrant the change in interpretation.

Devices installed to protect MAOP in accordance with sections 192.195 through 192.201 are subject to sections 192.731, 192.739, and 192.743. The code is silent on the requirements to maintain devices installed in accordance with sections 192.153 or 192.165. As a result, the next logical step is to review other industry standards to determine an appropriate inspection frequency. ASME BPVC, as incorporated, has capacities and setpoints defined in greater detail, designed to the MAWP of the vessel, and exclusive of the requirements of § 192.201(a). Devices protecting MAWP have never been addressed by interpretations or within the code because of the extremely

[37] Letter of Interpretation to David J. Chisela, Michigan Public Service Commission, PI-18-0010 (Oct. 4, 2018).
[38] *Id.*

low risk of their need – they are set above MAOP and only have capacities to relief the ASME vessel – not enough to relieve the pipeline.

PI-18-0010 does not consider the design and function of an ASME pressure vessel relief valve in service to protect MAWP and are only considering the protection of the MAOP, which is protected by other designed elements and required by 49 CFR Part 192.

The Office of Pipeline Safety recently established inspection and enforcement priorities in a memo issued on July 17, 2025.[39] In that memo, OPS directed its staff to avoid "relying on unduly broad, novel, or strained applications of the law or regulations."[40] The position in this 2018 interpretation is a strained application of the law and should be rescinded.

b. Clustering

PHMSA should revoke PI-14-0017, which relates to the clustering rule. Given the ongoing discussion and confusion over the definition of a cluster, PHMSA should rescind this interpretation and then provide clearer guidance. *See* the Associations' Response to Question B.7 for more information.

c. Property Damage Calculations

As discussed in its LNG ANPRM comments, INGAA seeks clarity on how PHMSA applies the property damage threshold for purposes of incident reporting. In PI-10-0026, PHMSA stated "for the determination of the property damage calculation, the cost of the damage to a vehicle striking a gas pipeline facility would normally be <u>included</u> in determining whether the incident was reportable."[41] Since the vehicle is responsible for the leak in this scenario, it should not be included in an operator's calculation of property damage. This interpretation should be rescinded.

In PI-18-0016,[42] PHMSA stated that the only property damage costs that need to be considered for reporting an incident are labor, equipment, and materials in responding to and repairing a gas leak. Having both interpretations for reliance by PHMSA inspectors and operator personnel creates unnecessary confusion. PHMSA should rescind both interpretations and provide clearer guidance.

d. Definition of Construction Activities

PHMSA should rescind Advisory Bulletin ADB-2014-03. The current overly broad interpretation of "construction" activities requiring notification under section 191.22 creates undue burden by requiring operators to evaluate routine maintenance and replacement projects for notification requirements. PHMSA should clarify that replacement in kind, rehabilitation to and/or within

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[39] PHMSA Inspection and Enforcement Priorities Memo dated July 17, 2025.
[40] *Id.* at 5 (citing U.S. DOT General Counsel Enforcement memo dated Mar. 11, 2025).
[41] Letter of Interpretation to Jason Montoya, Bureau Chief, New Mexico Public Regulatory Comm'n, PI-10-0026 (June 14, 2011).
[42] Letter of Interpretation to Sean Mayo, Pipeline Safety Director, Washington Utilities and Transportation Comm'n, PI-18-0016 (Oct. 4, 2018).

original design limits, and projects not related to DOT component safety do not require notification.

B. Topic Area: Pipeline Safety Regulations (Parts 190-199)

B.1. Regulatory Inefficiencies

What provisions of the PSR either impose an undue burden on identification, development, and use of domestic energy resources, or are examples of government inefficiency, insofar as they impose outsized compliance burdens for comparatively small safety benefits or limit technological innovation? Are there any PSR provisions that are unnecessary because their safety benefits that are adequately addressed by other PSR requirements?

The Associations have included its request for modifications of Part 190 in response to Question B.1. The Associations address specific subparts of Parts 192 and 193 in response to questions B.2-B.11.

1. Intra-Agency Coordination

The Associations encourage PHMSA to improve coordination within its own organization by ensuring that the various regions and departments coordinate their inspection activities for the same facilities. When multiple regions or divisions need to inspect the same facility, PHMSA should schedule joint inspections or share inspection findings to reduce the burden on operators. If one region or inspection team reviews a particular procedure that is part of a shared safety program,[43] then there should not be a need to review the same procedure at a different facility for the same operator. Streamlining this process will reduce the length of inspections and eliminate unnecessary requests for information.

Large-scale LNG facilities are subject to design and construction reviews that involve multiple departments within PHMSA. The PHMSA Engineering & Research Division and Field Operations departments conduct simultaneous reviews of the inspection question set. Operators may receive multiple requests for information, requests for inspection, and updates on IA question status from multiple PHMSA personnel. At times, these requests for information and inspections may overlap, and the operator often needs to manage multiple PHMSA personnel and communication between the groups to ensure priorities are met. Concurrent and overlapping requests also strain operator resources as, often, other federal agencies such as FERC are requesting information or inspections as well.

2. Timely Conclusions to Inspections

PHMSA should amend Part 190 to incorporate the DOT General Counsel's directive limiting on-site investigations to 10 business days or less.[44] The Associations recognize the importance of conducting inspections and investigations in a timely and efficient manner. Having a specific

[43] https://www.phmsa.dot.gov/data-and-statistics/pipeline/safety-program-data-pipeline-and-lng-operators

[44] DOT General Counsel Memorandum to Secretarial Officers and Heads of Operating Administrations: Procedural Requirements for DOT Enforcement Actions (Mar. 11, 2025) (DOT General Counsel Enforcement Memo), at 9.

deadline ensures that any potential safety issues are quickly resolved and provides certainty to the operators and the public on the pipeline safety enforcement process.

The Associations also seek certainty on the conclusion of the full inspection. While section 60108(e) of the Pipeline Safety Act provides that PHMSA has 30 days after completion of an inspection to complete a post-hearing inspection report and 90 days from completion of the inspection to provide written preliminary findings, often it is not clear when an inspection has actually concluded and when this clock begins to run. Further, many operators report that they routinely do not receive verbal exit briefings or written post-inspection reports.

Finally, PHMSA should update Part 190 to reflect the DOT's General Counsel memo which directed agency enforcement staff to "make a decision on pursuing an administrative action within 30 days of the completion of the inspection or investigation and commence an enforcement action as soon as possible thereafter."[45]

The Associations recommend the following amendments to § 190.203:

> **§ 190.203 Inspections and investigations.**
>
> (f) OPS must conclude on-site inspections within 10 business days. Within 30 days of completion of the entire inspection, OPS must provide a post-hearing inspection report to the operator and determine whether an enforcement proceeding is appropriate.
>
> (g) ~~When~~ If OPS determines that the information obtained from an inspection or from other appropriate sources warrants further action, OPS may initiate one or more of the enforcement proceedings prescribed in this subpart, not later than 90 days after the completion of the inspection.

3. Requests for Information

Section 190.203(c) allows the Regional Director to request further information through the Agency's formal Request for Information process.[46] In recent years, PHMSA inspectors are using this formal process to replace on-site inspections or supplement the record in enforcement. The Associations recommend that PHMSA revise section 190.203(c) to clarify the appropriate use of this tool.

The Associations' members also report that while the regulation has a default response timeframe of 30 days, the Agency's inspectors frequently request that operators respond to lengthy information requests within shorter timeframes such as 15 days. Pipeline facilities have become increasingly complex over time due to technological advancements and regulatory developments. Consequently, responding to a request for information may require operators to identify, gather, review, and compile information and data that is complex in nature. This can be resource- and time-intensive and may take operator staff away from executing normal and daily operational

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[45] *Id.*

[46] 49 CFR § 190.203(c).

duties. The Associations urge PHMSA to extend the response time deadline in § 190.203(c) from 30 days to 45 days, which would alleviate undue burdens.

The Associations recommend the following modifications to § 190.203(c):

> **§ 190.203(c) Inspections and investigations.**
>
> (c) If the Associate Administrator or Regional Director believes that further information is needed to determine appropriate action, the Associate Administrator or Regional Director may notify the pipeline operator in writing that the operator is required to provide specific information within ~~30~~ 45 days from the time the notification is received by the operator, unless ~~otherwise specified in the notification~~ the information is related to an incident. The notification must provide a reasonable description of the specific information required. An operator may request an extension of time to respond by providing a written justification as to why such an extension is necessary and proposing an alternative submission date. A request for an extension may ask for the deadline to be stayed while the extension is considered. General statements of hardship are not acceptable bases for requesting an extension. A Request for Information cannot be used during a pending enforcement proceeding.

4. Removing Requirement to Redact Documents Up Front

PHMSA should amend 49 CFR § 190.343 to remove the burdensome requirement that operators have to redact non-public information when they initially provide the information to PHMSA. This requirement actually slows down production of documents to the agency and numerous operators report that PHMSA inspectors accuse the operator of moving too slowly when operators are merely trying to comply with PHMSA's own regulation.

PHMSA should change the rule to be consistent with other federal agencies which require only that the documents be marked as confidential and not redacted during the initial submission:

> **§ 190.343 Information made available to the public and request for protection of confidential commercial information.**
>
> When you submit information to PHMSA during a rulemaking proceeding, as part of your application for special permit or renewal, or for any other reason, we may make that information publicly available unless you ask that we keep the information confidential.
>
> (a) *Asking for protection of confidential commercial information.* You may ask us to give confidential treatment to information you give to the agency by taking the following steps:
>
> (1) Mark "confidential" on each page of the original document you would like to keep confidential.
>
> ~~(2) Send us, along with the original document, a second copy of the original document with the confidential commercial information deleted.~~

~~(3) Explain why the information you are submitting is confidential commercial information.~~

(b) ***PHMSA decision***. PHMSA will treat as confidential the information that you submitted in accordance with this section, unless we notify you otherwise. If PHMSA decides to disclose the information, PHMSA will review your request to protect confidential commercial information under the criteria set forth in the Freedom of Information Act (FOIA), 5 U.S.C. 552, including following the consultation procedures set out in the Departmental FOIA regulations, 49 CFR 7.29. If PHMSA decides to disclose the information over your objections, we will notify you in writing at least five business days before the intended disclosure date.

B.2. Terms

Do any of the terms defined in the PSR impose an undue burden on affected stakeholders? Please identify any specific regulatory amendments that PHMSA should consider, as well as the technical, safety, and economic reasons supporting those recommended amendments.

1. Definition of an Incident

The Associations seek a modification to the definition of an incident. PHMSA currently defines an incident as including the "[u]nintentional estimated gas loss of three million cubic feet or more."[47] The Agency also provides that "[a]ctivation of an emergency shutdown system for reasons other than an actual emergency within the facility does not constitute an incident."[48] However, in the incident reporting instructions for gas transmission and gathering operators, the Agency takes the opposite approach and includes "volumes released during an Emergency Shutdown (ESDs) or relief valve activation" as reportable as an incident. The Agency provides that "when ESDs or relief valves are activated as the result of a safety condition that has occurred, the volume released should be included in the "unintentional" category, even if safety equipment performed as designed (such as a power loss or upon a PLC command)."[49] These statements are hard to reconcile with other guidance in the instructions that provide that "[t]he intentional and controlled release of gas for the purpose of maintenance or other routine operating activities is not to be reported."[50]

The Associations propose that PHMSA exempt those releases that occur through intended pathways. Gas loss events from designed process blowdowns, such as through relief valves or ESDs, should not be included in PHMSA incident reporting. These events are intentional and controlled releases designed to maintain the safety and integrity of the pipeline system. Relief valves and ESDs are critical components that prevent overpressure conditions and ensure the safe operation of the pipeline. When these devices actuate, they are performing their intended purpose of protecting the pipeline and surrounding environment from potential hazards. Including these

[47] 49 CFR § 191.3.
[48] *Id.*
[49] 2023 Incident Reporting Instructions, https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2023-12/Current_GT_GG_UNGS_Incident_Instructions_PHMSA%20F%207100%202_9-2023%20and%20Beyond.pdf (last accessed on August 1, 2025) at 8.
[50] *Id.* at 1.

designed safety measures in incident reporting could lead to an excessive number of reports that do not accurately reflect the true safety and risk profile of the pipeline system. These designed process blowdowns are managed as part of the pipeline's normal operation and maintenance procedures, and are not indicative of unexpected failures or hazardous conditions that PHMSA incident reports intend to capture. The inclusion of such events in incident reporting could divert attention and resources away from addressing actual incidents that pose a genuine risk to pipeline integrity and safety. By focusing on unplanned and hazardous events, PHMSA can concentrate its efforts on improving pipeline safety through more relevant and impactful measures.

The Associations propose the following modifications:

> *Incident* means any of the following events:
>
> (1) An event that involves a release of gas from a pipeline, gas from an underground natural gas storage facility (UNGSF), liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences:
>
> (i) A death, or personal injury necessitating in-patient hospitalization;
>
> (ii) Estimated property damage of $122,000 or more, including loss to the operator and others, or both, but excluding the cost of gas lost. 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.
>
> (iii) Unintentional estimated gas loss of three million cubic feet or more, not including releases through intended pathways as designed under Part 192.

The Associations also request that PHMSA review and revise its reporting instructions.[51]

2. LNG Definitions

INGAA has provided proposed changes to several definitions in Part 193 as part of its comments in response to the LNG ANPRM.[52]

3. General Terms

In some cases, PHMSA defines the same term across Parts 191, 192, 193, and 195. The Associations request that PHMSA reconcile these differences, where appropriate.

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[51] *See also,* Responses to Question A.7.

[52] Comments of the American Petroleum Institute, Center for LNG, Interstate Natural Gas Association of America, American Gas Association, American Public Gas Association, and Northeast Gas Association, Pipeline Safety: Amendments to Liquefied Natural Gas Facilities, https://www.regulations.gov/comment/PHMSA-2019-0091-7611, (July 7, 2025).

B.3. Identifying Burdens on Gathering Lines

Are there any requirements in the PSR that impose undue burdens on owners and operators of gathering lines? Please identify any specific regulatory amendments that PHMSA should consider, as well as the technical, safety, and economic reasons supporting those recommended amendments.

The requirement in 49 CFR § 192.9 to perform instrumented leak surveys on Type B gathering lines in class 2 areas and Type C gathering lines creates an inconsistent regulatory approach. This requirement is particularly problematic because instrumented leakage surveys are not required for transmission pipelines or Type A gathering lines in Class 2 areas or transmission lines in Class 1 and 2 areas, both of which typically operate at higher pressures and serve higher-consequence applications than Type B gathering systems. This regulatory inconsistency forces lower-risk facilities to face more stringent requirements than higher-risk systems, representing poor regulatory resource allocation and imposing significant costs on operators who must deploy specialized equipment and trained personnel for surveys that may not provide safety benefits proportional to the expense.

§ 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:

(8) Conduct leakage surveys in accordance with the requirements for transmission lines in § 192.706, ~~using leak-detection equipment~~, and promptly repair hazardous leaks in accordance with § 192.703(c).

(e) ***Type C lines****.* The requirements for Type C gathering lines are as follows.

(vii) Conduct leakage surveys in accordance with the requirements for transmission lines in § 192.706 ~~using leak-detection equipment~~, and promptly repair hazardous leaks in accordance with § 192.703(c).

The Associations have also included comments on reporting for Type R gathering lines in response to Question B.4 (Reporting).

B.4. Reporting and Notification Requirements

Do the reporting and notification requirements (e.g., part 191, § 193.2011, and part 195, subpart B) in the PSR impose an undue burden on affected stakeholders? Are any of those reporting requirements inefficient because of their limited safety value compared to their associated costs? Please identify any specific regulatory amendments that PHMSA should consider limited safety value compared to their associated costs? Please identify any specific regulatory amendments that PHMSA should consider, as well as the technical, safety, and economic reasons supporting those recommended amendments.

The Associations recognize that PHMSA uses reporting data for risk modeling and inspection scheduling. However, the Association has identified certain reporting requirements that should be modified or streamlined. While the Associations filed comments in response to the LNG ANPRM and DOT RFI that include reporting concerns, the Association has included some of the more critical changes to Parts 191 and 193 below.

1. Safety-Related Condition Reporting

a. Conditions that are immediately made safe upon discovery

As discussed in its comments in response to the DOT RFI,[53] the Associations continue to support reasonable changes to the safety-related condition reporting requirements. While the Associations recognize that PHMSA has a statutory obligation to prescribe and maintain regulations on safety-related condition reporting,[54] the Agency does have flexibility on how it defines the scope of each condition. The Agency's predecessors acknowledged when it first codified this reporting requirements that "…operators [a]re expected to disclose only glaring, hazardous conditions, which might, if left to linger, constitute an imminent danger or potentially cause an incident."[55] Yet, section 191.23(a)(9) includes language that expands beyond this statutory mandate and the intent of the initial regulations. Section 191.23(a)(9) is framed as a 20% or more reduction in operating pressure or shutdown of operation of a pipeline even if voluntarily implemented.[56] In support of this specific condition, the Agency stated that "[t]his proposal was put forth to clarify by regulation the statutory requirement that operators report 'any safety-related condition that causes or has caused a significant change or restriction in the operation of the pipeline facilities."[57] Yet, PHMSA inspectors have taken the position that a 20% reduction in pressure, no matter the reason, is reportable as a safety-related condition. This was not the intent of the statute or the initial code drafters.

Operators now overreport based on reinterpretation of this 20% pressure reduction language. For example, many of the Associations' members report immediate repair conditions that cannot be remediated with 5 working days from discovery simply because a 20% restriction is placed on the pipeline as required in 49 C.F.R. §§ 192.714 or 192.933. Taking a pressure restriction required by other sections of the PSR does not automatically make the condition a hazard to life, property, or the environment and does not always constitute a significant restriction in the pipeline facility. In

[53] INGAA Comments in Response to DOT RFI, https://www.regulations.gov/comment/DOT-OST-2025-0026-0872 (May 5, 2025).
[54] 49 U.S.C. § 60102(h)("(1) The Secretary shall prescribe regulations requiring each operator of a pipeline facility (except a master meter) to submit to the Secretary a written report on any—
(A) condition that is a hazard to life, property, or the environment; and
(B) safety-related condition that causes or has caused a significant change or restriction in the operation of a pipeline facility.
[55] Reporting Unsafe Conditions on Gas and Hazardous Liquid Pipelines and Liquefied Natural Gas Facilities, 53 Fed. Reg. 24,942, 24,943 (July 1, 1988).
[56] 49 CFR § 191.23(a)(9).
[57] Reporting Unsafe Conditions on Gas and Hazardous Liquid Pipelines and Liquefied Natural Gas Facilities, 53 Fed. Reg. at 24,945 (quoting Pub. L. No. 99-516, § 3).

the case of an immediate repair condition, it should only be considered a safety-related condition if a pressure reduction cannot be implemented or is left in place for a significant amount of time and impacts delivery to a customer.

Under the plain reading of the statutory requirements, conditions that are immediately made safe upon discovery, whether through a pressure reduction or other means, should not be reported as they are no longer a hazard, so long as the pressure reduction does not cause a significant change or restriction. The Associations request that PHMSA revise section 191.23 on this basis.

b. Terms Used in Section 191.23(a)

PHMSA currently references four terms in section 191.23(a) that are undefined: crack, material defect, structural integrity, serviceability, and reliability. The meaning of these terms is open to interpretation, creating compliance uncertainty for operators attempting to determine reporting requirements. Terms such as "crack," "material defect," "structural integrity," "serviceability," and "reliability" lack precise definitions, leading to inconsistent application across facilities and potentially inappropriate reporting of normal operational conditions or commissioning activities. PHMSA should clarify the meaning of the terms used in section 191.23(a).

c. Reporting during Commissiong and Start-Up

PHMSA should confirm that safety-related condition reporting is not required during commissioning and initial start-up phases of LNG projects when equipment testing and adjustment activities are normal parts of facility activation rather than safety concerns requiring regulatory notification.

2. Incident Reporting

a. Scope of 48-hour report

The Associations seek modifications to section 191.5(c), which provides that an operator must revise or confirm its initial telephonic notice within 48 hours of confirmed discovery of an incident.[58] This report creates an unnecessary administrative burden especially where no significant changes in circumstances have occurred. In cases where no change has occurred, the operator must still file the report and confirm the initial estimate of gas lost.[59] PHMSA deploys onsite inspectors for major incidents, making routine updates unnecessary for significant events, while minor incidents may not warrant any additional updates. PHMSA should restructure section 191.5(c) to only require the 48-hour update if major changes to the information initially filed occur.

b. Removal of the One-Hour Reporting Requirement

PHMSA should also reevaluate the inclusion of property damage in its one-hour reporting deadline. Section 191.5(a) provides that operators must report an event meeting the definition of an incident in section 191.3 within 1 hour of confirmed discovery.[60] In order to comply, in many

[58] 49 CFR § 191.5(c).
[59] *Id.*
[60] 49 CFR § 191.5(a).

situations, an operator must guess at the property damage or the amount of gas lost in order to determine if the event meets the definition of an incident and is reportable. It would be more feasible and PHMSA would get more accurate information if it required operators to report property damage calculations in the 30-day report and not as the sole trigger for an immediate notification.

c. Revisions to LNG Incident Report

The LNG Incident Form F7100.3 requires commodity cost information in Part C, lines C1f-C1h, which has no safety nexus and provides no value for safety analysis or regulatory oversight. PHMSA should eliminate these commodity cost reporting requirements.

3. Annual Reports

Several annual reporting requirements impose undue burdens. PHMSA requires operators to report the same information that does not change year to year, providing limited safety value while consuming administrative resources. For instance, the miles by MAOP determination method (Part Q) and miles of pipe by decade installed (Part J) sections of the 7100.2-1 annual report require natural gas pipeline operators to report the same information annually even when no changes in pipeline assets or MAOP status occurs. PHMSA should modify these requirements to apply only when operators must reconfirm MAOP, acquire pipeline assets, or add mileage due to construction. For operators who have not undertaken these activities, the information remains static and repeated annual reporting provides no additional safety value. It only consumes administrative resources that could be directed toward more productive safety activities.

The Liquefied Natural Gas Facilities Annual Report (Form 7100.3-1) also contains information with limited safety value that is already provided through other regulatory mechanisms. Information in the report duplicates data already available through the National Registry of Operators, FERC authorization processes, and EPA permit reporting protocols. Specific examples include:

- Leak information already reported to FERC semi-annually per project authorizing orders and through EPA permit reporting
- Emergency shutdown events reported to FERC semi-annually and to state/local authorities as appropriate
- Rollover incidents reported to FERC semi-annually per project authorization requirements
- Security breaches reported to Coast Guard under 33 CFR 101.305 and to FERC per project authorizing orders

4. National Pipeline Mapping Systems

The requirement for LNG facilities to submit annual geospatial data to the National Pipeline Mapping System under 49 CFR 191.29 provides no safety value for fixed installations that do not change location or configuration. Unlike pipeline systems that may be modified, extended, or altered and location is not apparent to the public, large-scale/baseload, small-scale/peak shaver, and satellite LNG facilities represent significant immovable investments at fixed locations that are visible to the public and well-documented in FERC and other regulatory records.

PHMSA states in section 191.29(b) that "[i]f no changes have occurred since the previous year's submission, the operator must comply with the guidance provided in the NPMS Operator Standards manual available at *www.npms.phmsa.dot.gov* or contact the PHMSA Geographic Information Systems Manager at (202) 366-4595."[61] The Operator Standards manual further provides that "[a] notification of no changes, in place of a data submission, fulfills the annual NPMS submission requirement."[62] Operators are directed to send a no change notification via email to NPMS staff.[63] The Associations agree with this email approach but it is not codified in section 191.29. Instead of directing operators to the Standards Manual for guidance, PHMSA should include an exception in section 191.29 for those LNG facilities where no changes occurred during the reporting period.

Additionally, the deadline to submit annual geospatial data to the National Pipeline Mapping System should be extended to June 15, matching the proposed deadline for natural gas annual reports.[64]

5. Construction Notifications

PHMSA should amend sections 191.22(c) and 193.2011 to clarify that construction notifications are not required for those events that are already subject to design review notifications.[65] In accordance with 49 CFR 191.22(c), operators must submit notifications for projects that are already subject to design review and prior notification under 49 CFR 190.403 and § 190.405. This duplication forces operators to provide essentially the same project information through multiple regulatory processes without providing additional safety oversight. PHMSA should clarify that notifications in accordance with section 191.22(c) are not required for projects already subject to design review and prior notification requirements. This modification would eliminate duplicative administrative processes.

PHMSA should also adjust the cost threshold for construction notification to account for inflation.

> **§ 191.22 National Registry of Operators.**
>
> (c) ***Changes.*** Each operator of a gas pipeline, gas pipeline facility, UNGSF, LNG plant, or LNG facility must notify PHMSA electronically through the National Registry of Operators at *https://portal.phmsa.dot.gov* of certain events.

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[61] 49 CFR § 191.29(b).
[62] National Pipeline Mapping System, LNG Plant Submission Process, https://www.npms.phmsa.dot.gov/SubmissionProcessOverviewLNG.aspx (last accessed on June 25, 2025).
[63] *Id.*
[64] Pipeline Safety: Adjust Annual Report Filing Timelines, 90 Fed. Reg. 28,047 (July 1, 2025).
[65] 49 CFR § 190.405.

(1) An operator must notify PHMSA of any of the following events not later than 60 days before the event occurs:

(i) Construction of any planned rehabilitation, replacement, modification, upgrade, uprate, or update of a facility, other than a section of line pipe, that costs $10 million or more. If 60-day notice is not feasible because of an emergency, an operator must notify PHMSA as soon as practicable; For adjustments for inflation observed in calendar year 2025 and beyond, changes to the cost threshold will be posted on PHMSA's website.

6. Part 192.18 Notifications

a. Timing of Review Period

The Associations continue to seek modifications to the review process for section 192.18 notifications. Beginning in 2019, PHMSA began accepting notifications from operators to inform the Agency of the use of "other technology" or "alternative equivalent technology."[66] The notification process was set up to give PHMSA 90 days to review. The regulation allows an operator to proceed 91 days after submitting the notification unless PHMSA objects or the Agency seeks more information.[67] However, the review of these notifications often extend past the 90-day mark leaving operators with an uncertain path forward. Numerous operators report that at the end of the 90-day period, PHMSA frequently asks for more time or more information without any set deadline for a decision. In fact, there are currently 46 notifications currently "under review" after the 90-day mark that were submitted in 2024 and 2025.[68] This is exactly the result stakeholders were trying to avoid when this notification process was first created. The Associations understand that in certain situations, the Agency needs more information. However, the review should not be indefinite. In order for the regulation to be useful and not delay critical transportation projects or engineered solutions to technical issues, operators need some certainty on when a decision will be made.

In order to balance these interests, the Associations propose that PHMSA allow for a single 30-day extension of the 90-day period. By establishing a definitive timeline, it will help operators plan and have some certainty about the potential timeframe. The Associations included this issue in its responses to the DOT RFI and also includes them in this docket.

The Associations propose the following changes to section 192.18.

§ 192.18 How to notify PHMSA.

(c)….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 the Associate Administrator for Pipeline Safety informing the operator

[66] 49 CFR § 192.18(c).
[67] *Id.*
[68] Review of PHMSA Integrity Assurance Notification Database (as of May 1, 2025).

that PHMSA objects to the proposal or that PHMSA requires additional time up and/or more information to conduct its review. PHMSA's time period to seek additional information will expire at the end of one 30-day extension.

b. Scope of 192.18 Notifications

There are 42 separate provisions within Part 192 that require notification through 192.18. In addition, and not including special permit notifications, there are 33 provisions across CFR 191 and 192 that also require notification to PHMSA but not through the prescribed means within 192.18. As operators seek to leverage alternative technologies that are fit for purpose in pipeline safety applications, PHMSA faces increasing volumes of notifications, each potentially requiring some manner of technical review. PHMSA should reevaluate the specific provisions requiring § 192.18 notification and only include those that are not feasible for review at a scheduled compliance inspection. These types of notifications distract PHMSA resources from addressing higher priority notifications. Rather, the operator should be accountable for implementing procedures compliant with these requirements subject to PHMSA inspection and enforcement. An operator should have justification including manufacturer's specifications and/or engineering documentation that shows adequacy of the other method, approach, or technique for the operator's system.

Additional strategies to increase notification efficiency include:

- Developing clear review protocols and response timelines: PHMSA could commit to transparent, enforceable deadlines for each stage of the notification review process, including required timeframes for requesting additional information or issuing a decision.
- Expanding digital tracking and reporting: The creation of an online and readily accessible portal that tracks the status of all submitted notifications and applications would improve accountability for both PHMSA and operators, while enabling proactive management of backlogs.
- Providing detailed guidance and standardized templates: PHMSA could issue updated guidance documents and standardized notification templates that provide for consistent review and evaluation.
- Facilitating regular stakeholder engagement: Workshops or roundtables between PHMSA staff and industry representatives could surface recurring bottlenecks and foster collaborative solutions to process inefficiencies.
- Hire independent third-party experts or engineering consultants who can evaluate notifications and applications on PHMSA's behalf. This approach could expedite technical reviews and allow for more timely resolution of operator notification submissions.

7. Reporting Requirements for Type R Gathering Pipelines

The reporting requirements in 49 CFR 191.1(c) for Type R gathering lines create an unnecessary administrative burden that has continued well beyond the data collection period needed to inform regulatory decision-making. PHMSA has collected comprehensive data on Type R gathering operations over the past three years, providing sufficient information to determine whether additional regulation is warranted. Type R gathering lines serve lower-risk applications with typically smaller diameters, lower operating pressures, and less population exposure compared to transmission systems, yet face ongoing reporting requirements that impose disproportionate administrative costs without meaningful safety benefits. PHMSA should eliminate these reporting requirements entirely, or alternatively, eliminate incident reporting while retaining only streamlined annual reports if some ongoing data collection is deemed necessary.

B.5. Incorporating by Reference Industry Standards

Are there any consensus industry standards or recommended practices (or updated editions thereof) that should be incorporated by reference into the PSR to eliminate undue burdens or improve government efficiency? Please identify the pertinent standards and recommended practices that PHMSA should consider incorporating by reference, the specific provisions of the PSR that should be used for that purpose, and the technical, safety, and economic reasons supporting those recommended amendments.

The Associations have reviewed standards and recommended practices that are not incorporated by reference in the PSRs and recommends the following modifications:

1. Updating to New Editions

PHMSA should create a regular schedule by which it reviews and updates new editions of standards or recommended practices that are currently incorporated in the regulations. Incorporating more current editions on a timely basis would allow operators to use advance technology and improve efficiencies.

2. API RP 1162 (3^{rd} edition)

PHMSA currently requires operators to comply with the 1^{st} edition of API Recommended Practice 1162 for public awareness purposes. That edition was published twenty-two years ago in 2003 and was incorporated in the pipeline safety regulations in 2005. It is significantly outdated. The third edition more clearly defines stakeholder audiences, messaging topics, baseline delivery frequencies and addresses collaborative programs. The first edition has outdated message delivery methods and/or media such as CDs, Newspapers and Magazines while the third edition encompasses current popular communication methods including social media, Virtual Meetings, Community Investments, and Digital Platforms (texting, apps, etc.).

The 3^{rd} edition also introduces the plan-do-check-act cycle within the framework of a public awareness program, aligning the focus on continuous improvement introduced in pipeline safety management systems (RP 1173). This newer edition clarifies "shall" statement requirements and establishes a standardized question set for trend analysis and consistent guidance to target audiences.

Along with significant safety benefits, modernizing public awareness requirements would result in significant operational savings. Operators cited potential savings of between $225,000 and $380,000 annually per operator in printing and postage costs by allowing digital campaigns. For one operator, the cost of a digital impression represented 1% of a direct mailing, providing an immense opportunity to realize savings while simultaneously improving effectiveness and efficiency.

3. ASME/ANSI B31G-1991 (Reaffirmed 2004), "Manual for Determining the Remaining Strength of Corroded Pipelines," 2004.

PHMSA currently incorporates the 1991 version of ASME/ANSI B31G (reaffirmed in 2024). The Agency should update this reference to the 2023 edition to reflect advanced steel-making technology and recognize certain other corrosion evaluation methods that have been successfully used in the pipeline industry. Both the strength and durability of newer pipeline steels have significantly improved, and many high-strength pipeline grades, such as X70 and X80, are being used. Additionally, many improved corrosion assessment models and technologies have been developed to improve the management of high-strength pipelines.

4. New Incorporation

The Associations recommend that PHMSA evaluate incorporating certain portions of the three new recommended practices into the PSRs. The Associations are willing to discuss incorporation of these RPs further with PHMSA.

API RP 1187 Pipeline Integrity Management of Landslide Hazards, 1st Edition, August 2024.

API RP 1187 provides guidance to manage the impact of external forces created by land movement, specifically landslides. It relates to requirements sections 192.714(f), 192.907(b), 192.911(c), 192.933 and 192.935(c). While these requirements are not very specific, these are the requirements referencing B31.8S for threats which does include specifics. Section 192.935(c) is the only requirement highlighting external forces.

API RP 1183 Assessment and Management of Dents in Pipelines, 1st Edition, November 2020

API RP 1183 contains detailed technical discussions on dent formation, strain and fatigue and failure modes and mechanisms. Operators rely on guidance contained in API RP 1183 to make informed decisions regarding the management of dents on their systems. Capitalizing on operators' ECA experiences and based on the guidance contained in API RP 1183, the Associations have collaborated with API to develop a new proposed ECA process for dents. The Associations recommend that PHMSA replace existing § 192.712I with this amended ECA process.

API RP 1176 Assessment and Management of Cracking in Pipelines, 1st Edition, July 2016, Reaffirmed 2024.

API RP 1176, Recommended Practice for Assessment and Management of Cracking in Pipelines, First Edition, Includes Errata 1 (2021) and Errata 2 (2022) provides the basis for an immediate depth-based criterion for cracking. The standard establishes "a depth greater than 70% of the nominal wall" as an immediate condition. The Associations recommend that PHMSA incorporate this standard by reference for use in § 192.714(d)(1)(v)(A) and § 192.933(d)(1)(v)(A), so that operators are not required to treat cracking with metal loss as an immediate repair condition unless depth reaches the 70 percent threshold, consistent with updated recommended practice.

5. Other Updates

As discussed in the Associations' LNG ANPRM comments,[69] PHMSA should update the following currently incorporated standards within 49 CFR 193.2013:

- American Gas Association, "Purging Manual" – 4th Edition, September 2018
- API Standard 620, 12th edition, October 2013
- ASME Boiler & Pressure Vessel Code, Section VIII, Division 1: 2023 edition

B.6. Material, Design, Testing, Construction, and Corrosion Control

Are there any material, design, testing, construction, or corrosion control requirements in parts 192 (subparts B through I), 193 (subparts C through E), and 195 (subparts C through E and H) of the Pipeline Safety Regulation that impose an undue burden on affected stakeholders? Please identify any specific regulatory amendments that PHMSA should consider, as well as the technical, safety, and economic reasons (include a description and number of the affected pipeline facilities) supporting those recommended amendments.

The Associations have reviewed the material, design, testing, construction, and corrosion control requirements in Parts 192 and 193 and identified those areas that impose undue burdens through redundant inspection requirements, unclear regulatory language, and impractical remediation timelines that do not account for project complexity and seasonal construction limitations.

1. Design

As discussed in the Associations' comments in response to the LNG ANPRM,[70] several provisions in 49 CFR Part 193 contain unclear language that creates compliance uncertainty and may result in unnecessary design constraints. In those comments, the Associations highlighted section 193.2167. The Associations stated that while vacuum jacketed pipe is an acceptable construction

[69] Comments of the American Petroleum Institute, Center for LNG, Interstate Natural Gas Association of America, American Gas Association, American Public Gas Association, and Northeast Gas Association, Pipeline Safety: Amendments to Liquefied Natural Gas Facilities, PHMSA-2019-0091-7611, (July 7, 2025) at 29.
[70] Comments of the American Petroleum Institute, Center for LNG, Interstate Natural Gas Association of America, American Gas Association, American Public Gas Association, and Northeast Gas Association, Pipeline Safety: Amendments to Liquefied Natural Gas Facilities, https://www.regulations.gov/comment/PHMSA-2019-0091-7611, (July 7, 2025) at 14.

method in NFPA 59A-2023,[71] it is not currently allowed by section 193.2167 (Covered Systems). Operators would have preferred to use vacuum jacketed pipe but have been forced to install unjacketed pipe within a drainage dike to meet the requirements of the code. Alternatively, PHMSA should clarify what is considered a covered impounding system.

In those previously submitted comments, the Associations also sought changes to building setback requirements. The Associations stated that Table 2.2.4.1 in NFPA 59A-2001 references distances from impoundment to buildings and property lines but in the subsequent versions of NFPA 59A, this table was revised to only reference property lines.[72] PHMSA inspectors interpret this table to require that all facility related buildings must meet these setback requirements. This unnecessarily increases the size of the facility and the potential exposure of longer piping runs. All buildings proposed within this setback distance are designed to withstand the hazards present and are involved in the LNG process. PHMSA should allow operators to follow Table 6.3.1 in NFPA 59A-2023 or other good engineering practices under a risk-based regulation. The Associations incorporate those comments in this document and requests that PHMSA review these concerns.

2. Equipment

a. Control Center Requirements for Small-Scale LNG Facilities

Likewise, the Associations have also raised concerns with section 193.2441 regarding control center attendance and how that regulation does not appropriately distinguish between large-scale facilities that warrant continuous oversight and smaller peak-shaving facilities where continuous attendance may be unnecessary and economically burdensome.[73] Small-scale facilities typically have simpler operations and lower throughput that do not justify the same staffing requirements as large baseload facilities. PHMSA should clarify that continuous attendance requirements apply primarily to large-scale/baseload LNG facilities, allowing smaller facilities to implement appropriate oversight measures that reflect their operational scale and complexity.

b. Power System Requirements

The use of "auxiliary" power in 49 CFR 193.2445 creates inconsistency with industry standard terminology and may cause confusion in system design and operation. Standard industry practice refers to "secondary" power systems, and regulatory language should align with established industry terminology to prevent misunderstanding.

PHMSA should update 193.2445(a) to state: "Electrical control systems, means of communication, emergency lighting, and firefighting systems must have at least two sources of a primary and secondary source of power which function so that failure of one source does not affect the

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[71] NFPA 59A-2023, section 13.5(2).
[72] *See* NFPA 59A-2023, Table 6.3.1.
[73] Comments of the American Petroleum Institute, Center for LNG, Interstate Natural Gas Association of America, American Gas Association, American Public Gas Association, and Northeast Gas Association, Pipeline Safety: Amendments to Liquefied Natural Gas Facilities, https://www.regulations.gov/comment/PHMSA-2019-0091-7611, (July 7, 2025) at 18 and 39.

capability of the other source." Section 193.2445(b) should be updated to refer to "secondary source of electrical power" rather than auxiliary generators.

3. Testing

a. Single Component Pressure Testing

The exemption to pressure testing within 192.503(e) should not be limited to a single replaced or added component. Often, Operators may need to replace multiple components at the same time. For example, an operator may choose to weld one or more flanges to a weld-in valve prior to installation. If both the valve and the flanges meet the requirement of 192.503(e)(1)-(3), and the welds have passed non-destructive testing in accordance with 192.243, a new pressure test should not be required.

§ 192.503 General requirements.

(e) If one or more components other than pipe ~~is~~ are the only items being replaced or added to a pipeline, a strength test after installation is not required, if the manufacturer of the component(s) certifies that:

(1) The component was tested to at least the pressure required for the pipeline to which it is being added;

(2) The component was manufactured under a quality control system that ensures that each item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the pressure required for the pipeline to which it is being added; or

(3) The component carries a pressure rating established through applicable ASME/ANSI, Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS) specifications, or by unit strength calculations as described in § 192.143.

(4) Any welds have passed non-destructive testing in accordance with section 192.243.

b. Relocated Pressure Valves

PHMSA should also exempt pressure vessels from the requirement to re-pressure test upon relocation, provided they pass visual inspection. Pressure vessels are often relocated for temporary use during certain types of projects, such as pigging or flare down operations. It is unnecessary to re-pressure test them each time.

§ 192.503 General requirements

(a) No person may operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced, other than temporary pressure vessels and associated piping that have been previously pressure tested, until-

4. Construction

Section 192.307 provides that "[e]ach length of pipe and each other component must be visually inspected at the site of installation to ensure that it has not sustained any visually determinable damage that could impair its serviceability."[74] This regulation creates redundant burden when combined with more specific inspection requirements elsewhere in the regulations. Section 192.461(c) requires that "[e]ach external protective coating must be inspected just prior to lowering the pipe into the ditch and backfilling, and any damage detrimental to effective corrosion control must be repaired." Since this inspection is normally completed using holiday detectors and other specific testing methods, it is more prescriptive and comprehensive than the general visual inspection required by 192.307.

The duplicative nature of these requirements requires operators to conduct multiple inspections of the same components without providing any additional safety value. PHMSA should eliminate section 192.307 from Part 192, as the more specific inspection requirements in other sections provide comprehensive coverage of potential damage detection needs while eliminating unnecessary duplication of inspection activities.

5. Corrosion Control

a. Remedial Measures Requirements

PHMSA added new repair criteria in §§ 192.712 and 192.714 through the implementation of its 2022 Final Rule (Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments).[75] In addition, § 192.485 was modified to include references to § 192.712. With the additions of §§ 192.712 and 192.714, § 192.485 is no longer needed. Section 192.485 provides general directions on remediating corrosion anomalies and is located in subpart I. The §§ 192.712 and 192.714 regulations provide specific guidance to remediate corrosion, cracks, dents, and other material anomalies. For regulatory clarity and to ensure future regulatory updates are correctly applied, the Associations request that § 192.485 be removed from the regulations since §§ 192.712 and 192.714 provide more specific repair guidance than § 192.485.

b. Revise Alternating Current (AC) Interference Remediation Timelines

The requirement in 49 CFR 192.473(c)(4) to complete AC interference remediation within 15 months after completing the survey (unless there are permit issues) does not account for the complexity of large AC mitigation projects that can require extensive design, procurement, and construction activities. Complex AC mitigation projects often require six months or more for design, bidding, contract award, and material procurement, leaving insufficient time for construction activities that may face seasonal constraints.

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[74] 49 CFR § 192.307.

[75] Comments of Interstate Natural Gas Association of America, GPA Midstream, and the American Gas Association, PHMSA-2025-0019 (July 21, 2025).

These projects can involve costs upwards of $10 million and require coordination with multiple utilities and right-of-way owners, making the current timeline impractical for complex installations. PHMSA should revise section 192.473(c)(4) to allow extended timelines for complex AC mitigation projects based on documented technical justification, including considerations for design complexity, seasonal construction limitations, utility coordination requirements, and project scale.

B.7. Operations and Maintenance

Are there any operating and maintenance requirements in parts 192 (subparts L through M), 193 (subparts F through G), and 195 (subpart F) of the PSR that impose an undue burden on affected stakeholders? Please identify any specific regulatory amendments that PHMSA should consider, as well as the technical, safety, and economic reasons (include a description and number of the affected pipeline facilities) supporting those recommended amendments.

In response to this question, the Associations reference its comprehensive comments filed in response to the Repair Criteria ANPRM and the LNG ANPRM. The Associations request that PHMSA consider those comments in conjunction with this response.

1. Emergency Response Requirements

Section 192.615(a)(2) is burdensome because the list of agencies that could respond would vary due to size and scope of the incident. That regulation provides that "[a]n operator must determine the responsibilities, resources, jurisdictional area(s), and emergency contact telephone number(s) for both local and out-of-area calls of each Federal, State, and local government organization that may respond to a pipeline emergency, and inform such officials about the operator's ability to respond to a pipeline emergency and the means of communication during emergencies."[76] Operators work with local agencies to immediately respond to the event and determine how to make safe as quickly as possible. Federal and state agencies may get involved after the immediate event is made safe. This requirement also overlaps with section 192.616 (d)(4) "*Steps that should be taken for public safety in the event of a gas pipeline release; and",* and therefore is not needed.

2. Class Location

The Associations recognize and appreciate the efforts that have been made in bringing the class location rule to completion, but there are other items that merit updating that will continue the modernization of class location analysis in § 192.5.

a. Meeting of the Gas Pipeline Advisory Committee

During the March 2024 GPAC meeting for the Class Location NPRM, GPAC members overwhelmingly voted to hold another class advisory committee meeting to discuss a more modern methodology for class analysis. This meeting has not yet taken place, so the Associations urge PHMSA to include the continued class location improvements in this current rulemaking. PHMSA should consider updating the regulations around class location analysis (§ 192.5) to allow operators alternative methods to the current 'sliding mile' process for identifying class locations.

[76] 49 CFR § 192.615(a)(2).

An alternative method should implore concepts used in Subpart O, like the potential impact radius or other risk-based analysis processes, that use modern technology and establish the class rating based on the specific conditions that impact each section of the pipeline individually.

b. Clustering

PHMSA should also clarify the meaning of "cluster" in § 192.5(c)(2). The "clustering" concept, first introduced in 1970, allows an operator to adjust the length of its class location boundaries in "thinly populated areas."[77] In the 1970 rulemaking, the Agency acknowledged that "…the proposed class location definitions could create a 2-mile stretch of high class location solely to protect a small cluster of buildings at a crossroad or road crossing."[78] In response, the Agency created the clustering rule which allows an operator to move the boundary of the class location to within 220 yards of the nearest building "[w]henever a Class 2 or 3 location is required by a *cluster* of buildings in otherwise open country."[79] PHMSA did not define 'cluster' in the regulations.

In 2018, arguably for the first time, PHMSA stated that "even a single house could form the basis of a second cluster..."[80] The text and history of the regulation does not support that position. The text of 49 CFR § 192.5(c) indicates that the Agency intended that a cluster would consist of multiple buildings, not a single house. The regulation provides that "[w]hen a cluster of *buildings* intended for human occupancy requires a Class 2 or 3 location, the class location ends 220 yards (200 meters) from the nearest building in the cluster."[81]

The rulemaking history also does not support this approach. In 1970, during the discussions of the Technical Pipeline Safety Standards Committee (the Committee), Mr. George White, Chief Engineer of the Tennessee Gas Pipeline Company, an industry member of the Committee, referred to a 'cluster' as a "*grouping* within one mile"[82] In 1992, in response to a proposal to amend the clustering rule, the American Gas Association asked the Agency to explain what constituted a cluster.[83] The Agency responded that "the term is used in its ordinary dictionary sense, and, in RSPA's experience, has not been a significant source of misunderstanding."[84] In 2004, PHMSA acknowledged that this particular definition (a number of similar things, a bunch, or a group) is the 'ordinary meaning' the Agency envisioned when it used the term 'cluster'.[85]

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[77] Establishment of Minimum Standards, 35 Fed. Reg. 13,248, 13,251 (Aug. 19, 1970).
[78] *Id.* at 13,251.
[79] *Id.* (emphasis added). *See also,* 49 CFR § 192.5(c)(1)-(2) (2017).
[80] Pipeline Safety: Class Location Change Requirements, 83 Fed. Reg. 36,861, 36,863 (July 31, 2018).
[81] 49 CFR § 192.5(c)(2)(emphasis added).
[82] Transcript of Technical Pipeline Safety Standards Committee, at 248:8-9 (June 24, 1970), https://www.regulations.gov/document?D=PHMSA-2014-0095-0034 (emphasis added).
[83] Comments of the American Gas Association, Docket No. PS-124; Notice 1 (Sept. 30, 1992), https://www.regulations.gov/document?D=PHMSA-2015-0073-0007.
[84] Regulatory Review; Gas Pipeline Safety Standards, 61 Fed. Reg. 28,770, 28,772 (June 6, 1996); PHMSA's reliance on the dictionary is consistent with the approach that courts have used in determining the ordinary meaning of terms that do not have any special legal significance. *See e.g.*, *Muscarello v. United States*, 524 U.S. 125, 128 (1998).
[85] PHMSA Letter of Interpretation, PI-04-0106 (A

PHMSA further confirmed this approach in 2011 by stating in an enforcement case that "[a] *group* of buildings within the class location unit is sometimes referred to as a 'cluster' of buildings."[86] While additional discussion will need to occur with the Agency to further confirm its position on the definition of a cluster, the Agency should acknowledge that, at a minimum, a cluster is not a single house.

c. Other Revisions

Sections 192.610(a) and (b) (Change in class location: change in valve spacing) create unnecessary complexity by establishing similar requirements with the only difference being whether pipe replacement involves 2 or more miles versus less than 2 miles. This creates confusion and a duplicative compliance burden without clear safety justification for the distinction. PHMSA should eliminate section 192.610(a) entirely and consolidate requirements under 192.610(b) with appropriate language covering all pipe replacement scenarios, simplifying compliance while maintaining safety requirements.

3. Engineering Critical Assessments-Section 192.632

Engineering Critical Assessments (ECA) have emerged as a pivotal methodology for reconfirming Maximum Allowable Operating Pressure (MAOP) on gas transmission pipelines, offering a data centric analytical alternative to traditional approaches such as hydrostatic testing and pipe replacement. By leveraging advanced analytical techniques and in-line inspection data, ECA enables operators to reconfirm the MAOP of a pipeline that supports both regulatory compliance and operational efficiency while minimizing service disruptions and environmental impact.
Over the past several years, operators have engaged with PHMSA in a series of ongoing discussions and reviews surrounding the implementation of the ECA process. While the *Final Rule 2019-20306, Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments* which introduced MAOP reconfirmation methods, including ECA as an approved method, came into effect in July 1, 2020, it notably did not mandate that operators receive PHMSA approval prior to utilizing their ECA methodology. Rather, the intent was for operators to proceed with their validated processes, relying on subsequent PHMSA inspections to ensure compliance rather than awaiting formal pre-approval. Specifically, the Final Rule states that operators may perform an ILI and a technical analysis to establish a safety margin equivalent to that provided by a pressure test, and the technical analysis requirements are provided in 192.712 which are cross referenced with the 192.632 ECA process.[87] As such, the technical requirements for conducting a Method 3 ECA for MAOP-R are already included in the regulation and do not require pre-approval by PHMSA for implementation.

Despite this regulatory clarity, PHMSA has opted to pilot ECA inspections by closely reviewing processes from various operators. This approach, while intended to enhance oversight, has in practice delayed operators' ability to fully utilize ECA. The review process often becomes

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pr. 20, 2004) (In the regulations, the term, "cluster" is used in its ordinary dictionary sense, and has not been a significant source of misunderstanding. The dictionary meaning is: a number of similar things together, a bunch, a group."

[86] *In the Matter of El Paso Pipeline Corp. and ANR Pipeline Corp.* at 3, CPF No. 4-2007-1007 (Mar. 10, 2011) (emphasis added).

[87] https://www.govinfo.gov/content/pkg/FR-2019-10-01/pdf/2019-20306.pdf, page 56, 52235

protracted, with feedback cycles extending beyond anticipated timelines, and requests for additional information or revisions surfacing late in the process. Such delays have introduced uncertainty into project planning, as operators cannot confidently move ahead with ECA-based MAOP reconfirmation until there is informal affirmation even though this is not a statutory requirement. The pursuit of clarity and consistency from PHMSA has led operators to invest significant resources in refining documentation, responding to evolving expectations, and, in some cases, postponing critical projects.

When reconfirming MAOP, using ECA is typically much more cost-effective and less disruptive than either pipe replacement or hydrostatic testing. ECA is expected to cost between $50,000 to $400,000 per analysis, dependent on the scope of the analysis and if any ILI or material verifications are required. In contrast, pipe replacement is by far the most expensive MAOP reconfirmation method, often exceeding $1 million per mile, and requires lengthy outages, environmental impacts including methane emissions and restoration work. Hydrostatic testing costs less than replacement, averaging approximately $850,000 per mile, but still imparts the same impacts as a pipe replacement. While ECA's savings and flexibility are clear, delays in non-mandatory process approval can limit its effectiveness and force operators to rely on more disruptive methods.

Building on these observations, there are several practical options to improve the implementation of MAOP reconfirmation using ECA. Reinforcing the regulatory intent of oversight through inspection, rather than implying pre-approval is required, would empower operators to proceed with ECA methodologies. Pilot programs, if necessary, should have defined scope, duration, and evaluation criteria to avoid indefinite delays. Industry and PHMSA can collaborate through regular stakeholder forums and technical advisory panels that would help maintain alignment on best practices, evolving analytical tools, and result in development of an industry standard practice. Together, these improvements would facilitate the timely and effective use of ECA, ensuring operators can deploy advanced, cost-effective, and environmentally friendly methods for pipeline safety and regulatory compliance while providing reliable use of natural gas.

PHMSA should also consider allowing operators to use ECA as a substitute to a 1.25 pressure test for existing pipelines in sections of Part 192 that require one. Currently, an MAOP ECA can only be used as a MAOP reconfirmation method in § 192.624(c)(3), even though this ECA type is equated to at least a 1.25 pressure test in § 192.624 since they both are established reconfirmation methods. An MAOP ECA should be an acceptable 1.25 (or 90% of SMYS) pressure test alternative in § 192.611, § 192.618, § 192.619, § 192.620, § 192.917, or any other section of § 192 where this would be applicable for existing pipelines. This would incentivize operators to include more sections of pipe in MAOP ECAs and consider ECAs as a more common reconfirmation method, resulting in more segments of pipelines receiving increased integrity and engineering focused analysis, which leads to higher overall safety of pipeline systems.

4. Control Room Management

PHMSA should reevaluate the requirements in section 192.631(h)(6). The current requirement provides that operators must have a controller training program that includes "[c]ontrol room team training and exercises that include both controllers and other individuals, defined by the operator, who *would reasonably be expected* to operationally collaborate with controllers (control room personnel) during normal, abnormal or emergency situations."[88] PHMSA should refocus the training on controllers and their immediate supervisors. The "would" language in the regulation is broad and can be misinterpreted. It also moves away from the original recommendation for a team training requirement. In 2012, the NTSB issued a recommendation to PHMSA to "[d]evelop requirements for team training of control center staff involved in pipeline operations similar to those used in other transportation modes."[89] PHMSA inspectors have interpreted this requirement to extend beyond the control room and conclude personnel that could interact with the control room.

5. Prescriptive LNG Facility Control System Testing Intervals and Allow a Risk-Based Approach

Current requirements in 49 CFR Part 193, Subpart G impose prescriptive testing intervals that do not reflect modern risk-based maintenance approaches or align with industry consensus standards. Section 193.2619(c) and (d) require pressure safety valve testing at intervals that ignore the fact that more than 90% of typical LNG plant pressure safety valves are in clean service and could be evaluated for testing once every 10 years per API RP 576-2024, section 6.9.1.

Large-scale/baseload LNG facilities could achieve annual cost savings of $2.5-3 million or more if sections 193.2619(c) and (d) were revised to allow risk-based scheduling for pressure safety valve testing. Small-scale/peak shaver facilities estimate savings of $29,000 per plant through more appropriate testing intervals based on actual service conditions and risk assessment.

Section 193.2619(c)(2) requires testing control systems intended for fire protection at six-month intervals that do not align with various NFPA standards. Testing frequency could be reduced to align with NFPA standards such as NFPA 72 Table 14.4.3.2 for gas detectors, which specifies annual rather than semi-annual testing frequency. Large-scale/baseload LNG facilities could achieve annual cost savings of approximately $600,000-750,000 through alignment with consensus standards while maintaining appropriate safety oversight.

The current requirements in 193.2619(c)(2) force large-scale/baseload LNG facilities to take maintenance outages to perform testing that could be accomplished through less disruptive methods or extended intervals based on risk assessment. These outages result in significant costs including approximately $400,000-500,000 annually in specialized labor costs and approximately $13.5 million per year in production losses for a typical 9-train large-scale facility.

6. Revise Atmospheric Corrosion Inspection Requirements for Large-Scale LNG Facilities

Section 193.2635(d) imposes rigid inspection requirements that do not reflect risk-based approaches consistent with industry standards such as API Standards 510, 570, and 580. Large-scale/baseload LNG facilities could achieve annual cost savings of approximately $3 million or more if PHMSA revised 193.2635(d) to align with established API standards that provide risk-based inspection intervals based on actual corrosion risk assessment.

[88] 49 CFR § 192.631(h)(6)(emphasis added).
[89] NTSB Safety Recommendation, P-12-007 (July 25, 2012).

7. Adopt a Risk-Based Approach for LNG Facilities

As discussed in the Associations' comments in response to the LNG ANPRM, PHMSA should implement a risk-based regulatory approach for large-scale/baseload LNG facilities as mandated by Section 110 of the PIPES Act of 2020. This approach would allow operators to develop maintenance and testing programs based on actual risk assessment rather than prescriptive intervals that may not reflect facility-specific conditions and service history.

B.8. Operator Qualification and Training

Are there any personnel qualification and training requirements in parts 192 (subpart N), 193 (subpart H), and 195 (subpart G) of the PSR that impose undue burdens on affected stakeholders? Please identify any specific regulatory amendments that PHMSA should consider, as well as the technical, safety, and economic reasons (include a description and number of the affected pipeline facilities) supporting those recommended amendments.

The Associations have identified qualification and training requirements in Parts 192 and 193 that impose burdens through contradictory or duplicative regulatory language.

1. Obsolete Deadlines

PHMSA should also eliminate the outdated transition provisions in § 192.809(c), (d), and (e) since the relevant timeframes have expired and these provisions no longer serve any regulatory purpose.

2. Refresher Training Frequency

The requirement in 49 CFR § 193.2713(b) for refresher training every two years is more frequent than industry standards and creates unnecessary training burdens without corresponding safety benefits. OSHA requires refresher training for the petrochemical industry every three years.[90] Given the similarities in operational risks and safety requirements between that industry and pipeline and LNG companies, PHMSA should amend 49 CFR § 193.2713(b) to three years. Aligning training intervals with industry standards would maintain safety effectiveness while reducing unnecessary burden, as demonstrated by successful application of three-year intervals in comparable industries.

3. Competency Requirements

The competency requirements in 49 CFR 193.2703 for design and fabrication personnel create an undue burden through vague language that allows inconsistent interpretation by inspectors. The current requirement for personnel to have "competence" in design or fabrication is challenged by inspectors who may have different interpretations of what constitutes adequate competence, particularly regarding the undefined number of years of experience required. This ambiguity is particularly burdensome as the LNG industry continues to grow and requires additional design and

[90] 29 CFR 1910.119(g)(2).

fabrication personnel who may have relevant qualifications but may not meet undefined experience thresholds.

PHMSA should amend 49 CFR 193.2703 to provide clearer competency standards that recognize various forms of qualification including training, certifications, and experience without arbitrary time requirements.

4. Security Training Requirements

The training requirements in 49 CFR § 193.2715 for security personnel create unnecessary duplication with Coast Guard regulations (33 CFR § 105). Operators of waterfront LNG facilities must comply with comprehensive Coast Guard security training requirements that address the same security concerns and training objectives as the PHMSA requirements, resulting in duplicative training programs without additional safety benefit. PHMSA should recognize compliance with 33 CFR § 105 regulations as adequate for security training requirements.

5. Emergency Response Training

The current training requirements in 49 CFR § 193.2717 focus solely on fire emergencies, creating a narrow scope that does not address other types of emergencies that personnel may encounter at LNG facilities. Modern LNG operations require personnel to be prepared for various emergency scenarios beyond fires, including hazardous material releases, process upsets, security incidents, and natural disasters.

PHMSA should expand the scope of § 193.2717 to address comprehensive emergency response training.

6. Transition to Competence-Based Training Models

PHMSA should consider adopting competence-based training models similar to those referenced in section 193.2713, which focus on demonstrated capabilities rather than prescriptive training intervals or arbitrary experience requirements. Competence-based approaches allow operators to tailor training programs to individual needs and job requirements while ensuring that personnel demonstrate the necessary knowledge and skills for safe operations.

B.9. Integrity Management

Do any of the integrity management requirements in part 192 (subparts O and P) or 195 (§§ 195.450 through 452) impose an undue burden on affected stakeholders? Please identify any specific regulatory amendments that PHMSA should consider, as well as the technical, safety, and economic reasons (include a description and number of the affected pipeline facilities) supporting those recommended amendments.

The Associations submitted comprehensive comments in response to PHMSA's Repair Criteria ANPRM,[91] that specifically addressed many of the sections of the integrity management regulations. The Associations incorporate those comments by reference in this docket. Of particular note, The Associations ask that PHMSA revise the repair and remediation approaches based on risk-based assessments using current industry recommended practices,[92] and revise predicted failure pressure requirements.[93] The Association also provides several additional integrity management topics below:

1. Integrity Assessments

PHMSA should clarify that integrity assessments are not required for facilities such as meter and regulator stations and compressor stations. Historically, there have been varying interpretations by PHMSA regarding the applicability of integrity assessments to these facilities. The coverage of baseline and integrity management reassessments is defined in sections 192.919, 192.921, and 192.937. These sections refer specifically to line pipe and not facilities.

PHMSA's enforcement guidance does not clarify the issue. In that guidance document, PHMSA provides that the requirements of Subpart O apply to all gas transmission pipelines including compressor stations, metering stations, regulator stations, valve sets, and other fabricated assemblies, but "for pipeline facilities other than "line pipe," an assessment may not necessarily be required."[94] There are also FAQs but they are unclear.[95]

The regulations do not include a definition of the term, line pipe, used in Subpart O. The Associations recommend inclusion of a definition for "line pipe" as well as one for "non-line pipe" to clarify how integrity assessments would apply. Relying on API 5L,[96] The Associations recommend the following definitions:

PHMSA should define *line pipe* as "pipe used exclusively in a line section" A line section is already defined in Part 192 as "a continuous run of transmission line between adjacent compressor stations, between a compressor station and storage facilities, between a compressor station and a block valve, or between adjacent block valves."[97] Line pipe does not include instrumentation, controls, regulators, valves, compression, sampling pipe, and other components and appurtenances that might be attached to line pipes and/or valves in a line section or transmission line. The term line pipe, thus, designates long line or cross-country piping where the fit-up, joining, and final placement of the piping is almost entirely conducted in a linear fashion. Line pipe is joined with circumferential welds or mechanical couplings and is generally installed as received from the

[91] Interstate Natural Gas Association of America, American Gas Association, and GPA Midstream Association. "Comment on Pipeline Safety: Repair Criteria for Hazardous Liquid and Gas Transmission Pipelines." Docket No. PHMSA-2025-0019, Comment PHMSA-2025-0019-0022. Regulations.gov. July 21, 2025.
[92] *Id.* at Section III.A.
[93] *Id.* at Section III.C.
[94] Gas Transmission Integrity Management Enforcement Guidance dated December 7, 2015.
[95] https://www.phmsa.dot.gov/pipeline/gas-transmission-integrity-management/gas-transmission-integrity-management-faqs. 8-26-2021.
[96] API Specification 5L, Line Pipe, 46th edition, April 2018, including Errata 1 (May 2018), (API Spec 5L); IBR approved for §§ 192.55(e); 192.112(a), (b), (c), (d), and (e); 192.113; appendix B to part 192.
[97] 49 CFR § 192.3.

manufacturer. Minor field modifications such as pipe bends (including wrinkle bends) or reducing pipe joint length (short joints or pups) are allowed.

The Associations also recommend adding a definition for non-line pipe component so there is no ambiguity.

Non-line pipe component means any component, other than line pipe, in a line section. Non-line pipe components may include valves, flanges, fittings, fabricated assemblies, other pressure retaining components, appurtenances, and pipes, which are not line pipes. Thus, “line pipes” and “non-line pipe components” are mutually exclusive.

Inclusion of definitions for line pipe and non-line pipe components will clarify the intent of integrity assessments in Subpart O. Applying these assessments to facilities provides no safety benefit. Several Association members have undertaken integrity assessments in facilities in HCAs such as meter and regulator stations and compressor stations, either through the use of direct assessment or direct examination. None of these companies have ever found an actionable anomaly as a result of these assessments, and in some cases, multiple assessments. Instead, these assessments should be limited to line pipe.

2. Requirements Outside High Consequence Areas

Some of the current requirements in 49 CFR 192.710 for assessments outside high consequence areas impose unnecessary burdens by limiting an operator’s flexibility to select appropriate assessment methods based on specific pipeline risks and characteristics. This prevents operators from relying on proven industry research and engineering analysis to determine the most effective assessment approach for their specific assets. This one-size-fits-all approach may result in less effective risk management while increasing compliance costs without corresponding safety benefits.

PHMSA should revise 49 CFR 192.710(c)(7):

§ 192.710 Transmission lines: Assessments outside of high consequence areas.

Assessment method. The initial assessments and the reassessments required by paragraph (b) of this section must be capable of identifying anomalies and defects associated with each of the threats to which the pipeline segment is susceptible and must be performed using one or more of the following methods…

(7) ~~***Other technology.*** Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator must notify PHMSA in advance of using the other technology in accordance with § 192.18.~~

Other Methodology. Operators may use other methodologies, proven by industry research or reliable engineering tests and analyses to address the appropriate assessment method for the specific risk(s) on their pipeline facility.

3. Advance Notification Requirements for Critical Work

PHMSA should remove the advance notification requirement from 49 CFR 192.607(e)(5) for alternative sampling methodologies. The requirement in 49 CFR 192.607(e)(5) for advance notification to PHMSA before using alternative sampling methods creates unnecessary delays that could impact an operator's ability to meet the 50% MAOP reconfirmation requirement by 2028 or 100% by 2035 as required by 49 CFR 192.624. This advance notification requirement slows pipe material verification efforts and are unnecessary because operators are already required to maintain thorough documentation and provide sound technical justifications for these methodologies.

4. Risk-Based Integrity Management Approach

The current distinction between class locations and the separate treatment of high consequence areas (HCAs), medium consequence areas (MCAs), and non-covered areas creates unnecessary complexity and may not optimize safety outcomes. PHMSA should consider adopting a comprehensive risk-based integrity management program that addresses all areas within unified Subparts M and O requirements, allowing operators to focus resources based on actual risk rather than geographic classifications. For example, for sections 192.933 through 192.943, PHMSA should allow operators to determine actions for integrity issues, additional preventive and mitigative measures evaluation, and reassessment intervals based on risk-based programs rather than prescriptive requirements.

A risk-based integrity management approach would enhance safety by allowing operators to focus resources on actual risks rather than compliance with prescriptive requirements that may not address site-specific conditions. Industry recommended practices reflect current research, operational experience, and technological advances that may provide superior safety performance compared to regulatory requirements that become outdated over time. By implementing these changes, PHMSA would reduce regulatory burden while supporting improved safety outcomes.

5. Actions to Address Particular Threats - 192.917(e)(4)

The requirement in 49 CFR 192.917(e)(4) to review all covered or non-covered segments in the pipeline system with such pipe to determine if a specific covered segment has a seam related threat should be eliminated since § 192.710 and § 192.714 have been added to the regulations. The term "pipeline system" is not defined in the regulation and is subject to interpretation by operators and regulatory agencies. Additionally, application of the term "such pipe" is challenging due to the variability of the operating and environmental conditions with any given pipe segment. Similar pipe or such pipe is difficult to identify on an operator's system due to the different characteristics of these pipe segments from the standpoint of maintenance history, testing history, cathodic protection, environmental conditions, external loading, and other differing operating environments. Due to the addition of § 192.710, significant pipeline mileage outside of HCAs requires detailed review and threat identification, as well as integrity assessments, that did not have this requirement prior to the Mega Rule. These individual segments should have accurate threat identifications based on data specific to the pipeline segment instead of generalized threats based on similar pipe across an operator's system. Section 192.714 provides repair criteria for certain onshore transmission pipeline segments outside of HCAs, similar to the repair requirements of § 192.933 for high consequence areas. The requirement to review all covered and non-covered segments is no longer needed in section 192.917(e)(4) due to these updated regulations.

PHMSA should also remove the reference to § 192.712 from § 192.917(e)(4). The analysis required by § 192.712 must be performed "whenever required by this part" and other sections of the regulation already direct the use of § 192.712 more appropriately than the threat identification section of subpart O.

The PHMSA IMP FAQs 219 and 220 state that § 192.917(e)(3) 1.25 * MAOP pressure test stabilizes manufacturing and construction defects, including those listed in § 192.917(e)(4). To ensure clarity, section 192.917(e)(4), PHMSA should note that a 1.25 x MAOP pressure test can stabilize the manufacturing and construction threats on low frequency ERW pipe, lap welded pipe, pipe with longitudinal joint factor less than 1.0, or other pipe that satisfies the conditions specified in ASME B31.8S. Additionally, PHMSA should remove "or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding 5 years" from § 192.917(e)(4) since a 1.25xMAOP applies stabilizes manufacturing and construction defects and would still apply to the pipe segment as long as the pressure did not exceed test pressure divided by 1.25.

An engineering critical assessment (ECA) assesses manufacturing and construction defects, including seam defects. PHMSA has already established that an ECA provides an equivalent level of safety as a pressure test. This was done when § 192.624 and § 192.632 were established making an ECA an alternative to a pressure test to reconfirm MAOP. Although MAOP reconfirmation methods (including ECA) are allowed for baseline assessments and reassessments according to § 192.921(i) and § 192.937(d), respectively, § 192.917(e)(3) states manufacturing and construction-related defects are considered stable only if the segment has a 1.25xMAOP hydrostatic pressure test. This could deter operators from using ECA given they may still be required to strength test to stabilize these threats or perform strength tests with little risk benefit on segments assessed using ECA. The Associations request that PHMSA allow operators to utilize the ECA process as defined in § 192.632 to stabilize the manufacturing or construction threats.

> **§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?**
>
> (e) ***Actions to address particular threats***. If an operator identifies any of the following threats, the operator must take the following actions to address the threat.
>
> (3) ***Manufacturing and construction defects***. An operator must analyze the covered segment to determine and account for the risk of failure from manufacturing and construction defects (including seam defects) in the covered

segment. The analysis must account for the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects only if the covered segment has been subjected to hydrostatic pressure testing satisfying the criteria of subpart J of at least 1.25 times MAOP or if an engineering critical assessment has been completed on the segment (§ 192.632), and the covered segment has not experienced a reportable incident attributed to a manufacturing or construction defect since the date of the most recent subpart J pressure test or engineering critical assessment. If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high-risk segment for the baseline assessment or a subsequent reassessment.

(i) The pipeline segment has experienced a reportable incident, as defined in § 191.3, since its most recent successful subpart J pressure test or engineering critical assessment, due to an original manufacturing-related defect, or a construction-, installation-, or fabrication-related defect;

6. Actions to Address Particular Threats - §§ 192.917(e)(5) and 192.917(e)(6)

PHMSA should consider removing 49 CFR §§ 192.917(e)(5) and (e)(6) from the regulation since § 192.933 already specifies the repair requirements inside of HCAs and § 192.714 specifies the repair requirements outside of HCAs. The requirements in 49 CFR §§ 192.917(e)(5) and (e)(6) to evaluate and remediate all covered and non-covered segments with similar characteristics after identification of corrosion or cracking are no longer necessary in the regulation. When subpart O was initially published, no assessment requirements existed for areas outside of HCAs (i.e. non-covered segments). PHMSA added § 192.710 which requires integrity considerations and assessment of certain onshore transmission pipeline segments outside of HCAs. This regulation requires assessments capable of identifying anomalies and defects associated with each of the threats to which the pipeline segment is susceptible. PHMSA also added § 192.714 which provides repair criteria for certain onshore transmission pipeline segments outside of HCAs, similar to the repair requirements of § 192.933 for High Consequence Areas. Because of these new regulations, the requirements in 49 CFR §§ 192.917(e)(5) and (e)(6) are not necessary due to prescriptive repair requirements for areas outside of HCAs.

B.10. Siting Requirements in Part 193 for LNG Facilities

Do any of the siting requirements for LNG facilities in 49 CFR part 193, subpart B, impose an undue burden on affected stakeholders? Please identify any specific regulatory amendments that PHMSA should consider, as well as the technical, safety, and economic reasons (include a description and number of the affected pipeline facilities) supporting those recommended amendments.

The siting requirements for LNG facilities in 49 CFR Part 193, Subpart B impose undue burdens on operators through reliance on obsolete modeling software, outdated consensus standards, and unnecessarily restrictive setback requirements that do not reflect current industry practices or technological advances in hazard analysis and facility design. The Associations submitted detailed comments in response to PHMSA's LNG ANPRM. The Associations incorporate those comments in this docket and requests that PHMSA consider them in conjunction with this response as part of a comprehensive approach to updating Part 193 requirements.

1. Obsolete Modeling Software Requirements

The current regulations incorporate modeling software by reference that is no longer used by the LNG industry due to significant technical limitations that make these tools inappropriate for modern facility design and hazard analysis. Specifically, 49 CFR 193.2059(a) incorporates GRI-96/0396.5 "Evaluation of Mitigation Methods for Accidental LNG Releases, Volume 5: Using FEM3A for LNG Accident Consequence Analyses" and GTI-04/0049 "LNG Vapor Dispersion Prediction with the DEGADIS 2.1: Dense Gas Dispersion Model for LNG Vapor Dispersion." These modeling tools suffer from fundamental limitations that render them inadequate for current large-scale LNG facility design and siting analysis.

DEGADIS is a two-dimensional software that does not account for elevation changes, plant geometry, or other critical factors that significantly affect vapor dispersion patterns in real-world applications. FEM3A is not commonly used by operators for hazard modeling due to its limitations, including assumptions of unobstructed, level terrain that do not reflect actual facility conditions. These limitations require operators to either use inadequate modeling tools that may not provide accurate safety analysis, or to seek alternative approaches through special permits or interpretations, adding regulatory complexity and cost without corresponding safety benefits. The industry has moved to more sophisticated computational fluid dynamics (CFD) modeling tools that provide more accurate and comprehensive hazard analysis capabilities. Operators currently utilize Phast 6.6, 6.7, and 8.4, which were approved by PHMSA in 2011 and 2021 respectively, and FLACS, which was approved by PHMSA in 2011 as documented in PHMSA FAQ H6. These modern tools provide three-dimensional analysis capabilities that account for complex facility geometry, terrain features, and atmospheric conditions, resulting in more accurate safety assessments and more efficient facility designs. Operators must either comply with technically inadequate modeling requirements that may not provide optimal safety analysis or invest additional resources in special permit processes to utilize more appropriate modern modeling tools.

PHMSA should revise 49 CFR Part 193, Subpart B to remove GRI-96/0396.5 and GTI-04/0049, and instead reference the modern modeling tools already approved by PHMSA, including current versions of Phast and FLACS software that reflect technological advances in dispersion modeling and computational fluid dynamics.

2. Outdated Consensus Standards

As discussed in the Associations' comments in response to the LNG ANPRM, Part 193 references NFPA 59A-2001 (Table 2.2.4.1) for setback distances to buildings and property lines which imposes unnecessary constraints on facility design and does not provide corresponding safety benefits. This outdated standard unnecessarily increases facility size requirements and potentially exposes operators to longer piping runs that may actually increase risk exposure. All buildings proposed within setback distances are specifically designed to withstand the hazards present and are integral to LNG process operations, making the rigid application of outdated setback tables counterproductive to overall facility safety. Later versions of NFPA 59A, including the 2023 edition, have evolved to focus on property line distances rather than maintaining separate requirements for buildings and property lines, reflecting improved understanding of risk management and facility design principles. NFPA 59A-2023 provides more flexible approaches that allow operators to demonstrate equivalent safety through risk-based analysis and good engineering practices, potentially reducing facility footprint while maintaining or enhancing safety performance. The unnecessarily restrictive setback requirements can significantly increase land acquisition costs, extend piping runs that increase both capital and operational costs, and may force suboptimal facility layouts that compromise operational efficiency.

PHMSA should revise 49 CFR 193.2051 to remove the specific reference to NFPA 59A-2001 Table 2.2.4.1 and, instead, incorporate subsequent versions of NFPA 59A that focus on property line distances and incorporate risk-based approaches. This change should allow operators to utilize NFPA 59A-2023 or demonstrate equivalent safety through good engineering practices under a risk-based regulatory framework.

B.11. Drug and Alcohol Testing Requirements in Part 199

Do any of the drug and alcohol testing requirements in part 199 (which incorporates by reference Departmental requirements at 49 CFR part 40) impose an undue burden on affected stakeholders? Please identify any specific regulatory amendments that PHMSA should consider, as well as the technical, safety, and economic reasons (include a description and number of the affected pipeline facilities) supporting those recommended amendments.

Certain PHMSA drug and alcohol testing requirements in Part 199 place undue burdens on operators due to ambiguous definitions for "covered employee" and "covered function", outdated administrative procedures, inconsistent terminology, and inappropriate contractor oversight.

1. Clarify Ambiguity in "Covered Employee" and "Covered Function" Definitions

The definition of "covered employee" in Part 199 is vague and unclear, which has led to inconsistent cross-industry application of the drug and alcohol testing regulations on operator's employees. A "covered employee, employee, or individual to be tested" is defined as "a person who performs a covered function, including persons employed by operators, contractors engaged by operators, and persons employed by such contractors."[98] A "covered function" is further defined as "an operations, maintenance, or emergency response function regulated by parts 192, 193, or 195…that is performed on a pipeline or on an LNG facility."[99]

Operators often face difficulty in determining whether an employee is performing a "covered function" for the purposes of the "covered employee" definition in Part 199. This ambiguity creates inconsistent testing pool decisions, increases recordkeeping burdens, and generates audit risks despite good-faith compliance efforts by operators.

[98] 49 CFR § 199.3.
[99] *Id.*

PHMSA should provide clear interpretive guidance or develop a decision tree to help operators consistently evaluate whether an employee qualifies as a "covered employee." The guidance should clarify what role-based documentation, such as job descriptions and training records, would be sufficient for compliance validation. Additionally, PHMSA should clarify in 49 CFR § 199.3 that a “covered function” excludes "administrative or professional work duties that do not perform operations, maintenance, replacement, modification, or emergency response functions, or supervision and/or direction of such functions." This clarification would promote consistency across industry operations and reduce unnecessary testing of personnel whose work does not affect pipeline safety.

2. Ease Administrative Burdens for Collecting Signatures

While the transition to electronic Custody and Control Forms (eCCFs) has modernized collection and documentation processes, the existing rules around correcting technical issues impose disproportionate administrative burdens.[100] Manual reprinting and wet signature collection requirements due to signature pad failure or printer issues significantly slow administrative workflows and require overnight document shipping for otherwise compliant collections. For operators with approximately 50 testing locations, these technical issues arise 1 to 2 times per month, creating unnecessary friction between third-party collectors, laboratories, and internal compliance teams.

PHMSA should urge the Department to amend its drug and alcohol testing regulations in 49 CFR Part 40 to allow collectors to provide digital attestation or brief electronic notation in lieu of wet signatures on reprinted lab copies, provided the original collection was conducted in compliance and documented in the eCCF platform.[101] This change would reduce administrative delays and costs while preserving specimen integrity and chain-of-custody standards that are essential for program effectiveness.

3. Standardize Terminology to Reduce Regulatory Complexity

The use of differing terminology in Part 199 creates unnecessary confusion and potential for compliance risk. Specifically, Part 199 uses "reasonable suspicion" for alcohol testing and "testing based on reasonable cause" for drug testing, when these refer to essentially the same testing trigger.[102] PHMSA should update 49 CFR 199.105 and 49 CFR 199.225 to use consistent terminology, specifically adopting "testing based on reasonable cause" for both drug and alcohol testing programs. This standardization would eliminate confusion and reduce the risk of compliance errors arising from terminology inconsistencies.

4. Revise Contractor Oversight Requirements

Section 199.115(a) requires operators to maintain responsibility over contractor compliance with the drug testing requirements in Part 199. The current Drug and Alcohol Management Information System (DAMIS) process places operators at compliance risk by making them responsible for

[100] 49 CFR § 40.205.
[101] 49 CFR § 40.83.
[102] PHMSA has previously recognized the use of differing terminology but noted that there is no clear distinction between “reasonable suspicion” and “reasonable cause.”

ensuring contractor testing percentages are met, despite operators having no visibility into contractor compliance until after contractors submit their information. This structure inappropriately assigns liability to operators for contractor activities beyond their control and creates unnecessary compliance risk.

PHMSA should amend 49 CFR 199.115 and 49 CFR 199.245 to clarify that the operator is responsible initially for reviewing a contractor's program and then for making all reasonable efforts to ensure that the requirements of the drug testing requirements of Part 199 are complied with rather than maintaining absolute responsibility for contractor compliance activities that operators cannot directly control. This change would appropriately allocate responsibility while maintaining operator oversight of contractor qualifications and testing compliance.

5. Inappropriate Random Drug Testing Percentage Triggers

Current regulations increase random drug testing percentages based on random test positive rates rather than focusing on more meaningful indicators of program effectiveness. Random testing positive rates can fluctuate due to statistical variation and testing timing rather than indicating actual safety concerns. PHMSA should amend 49 CFR 199.105(c)(4) to base random testing percentage increases on post-accident and reasonable cause testing positive rates, which more accurately reflect safety-related drug use patterns. The Associations provide the following regulatory text:

> **§ 199.105 Drug tests required.**
>
> (c) ***Random testing.***
> (3) When the minimum annual percentage rate for random drug testing is 25 percent, and the data received under the reporting requirements of § 199.119 for any calendar year indicate that the reported positive rate for post-accident testing or testing based on reasonable cause is equal to or greater than 1.0 percent, the Administrator will increase the minimum annual percentage rate for random drug testing to 50 percent of all covered employees.

6. Revise Post-Accident Testing Requirements for Uninvolved DOT-Covered Employees

The post-accident drug and alcohol testing requirements in Part 199 require an operator to drug and alcohol test each surviving covered employee "whose performance of a covered function either contributed to the accident of cannot be completely discounted as a contributing factor to the accident."[103] These post-accident testing requirements require operators to include DOT-covered employees who were not directly involved in incidents. This may include: (1) personnel who were present at or near the site but had no causal or corrective role; (2) employees whose job classification falls under DOT coverage but had no operational link to the event; and (3) staff referenced in proximity-based reporting without clear thresholds for inclusion. Such a broad inclusion of operator personnel creates disproportionate administrative burdens and introduces

[103] 49 CFR §§ 199.105(b) and 199.225(a).

ambiguity around compliance expectations while increasing the risk of over-reporting individuals whose involvement had no impact on the incident.

PHMSA should amend the requirements in Part 199 to limit post-accident testing to individuals with direct causal, corrective, or responsive roles in an accident or incident. The amended regulations should also allow operators to exclude passive or peripheral personnel without triggering compliance concerns.

7. Consider a Risk-based Approach to Drug and Alcohol Testing

PHMSA should consider amending Part 199 to allow operators to implement risk-based drug and alcohol testing policies that align with the National Academy of Sciences Aviation Safety Panel (NASAP) and Department of Defense Counterdrug and Chemical Hazards Analysis (DCCHA) processes. Risk-based approaches would allow operators to focus testing resources on higher-risk activities while potentially testing for additional substances beyond the standard prohibited drugs list where operational risks warrant enhanced testing. This approach would improve safety outcomes while reducing regulatory burden by allowing operators to tailor programs to their specific operational risks and employee populations.

These recommended changes would reduce regulatory burden while maintaining or enhancing safety outcomes by focusing testing requirements on personnel and situations that directly affect pipeline safety, clarifying administrative procedures that currently create unnecessary compliance costs, and allowing operators to implement more effective, risk-based testing approaches.

IV. Conclusion

The Associations appreciate the opportunity to provide comments in response to the ANPRM.

Respectfully submitted,

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