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-2025-10090

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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August 4, 2025

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I. Introduction

The American Gas Association (AGA)[1] respectfully submits these comments in response to the Pipeline and Hazardous Materials Safety Administration's (PHMSA) Advance Notice of Proposed Rulemaking (ANPRM) for Mandatory Regulatory Reviews to Unleash American Energy and Improve Government Efficiency[2]. AGA represents more than 200 local energy companies committed to the safe and reliable delivery of clean natural gas to more than 180 million Americans. Our members are dedicated to enhancing pipeline safety and support practicable, technically feasible, and cost-effective regulations.

II. Comments

A. Procedural Regulations

1. Procedural Regulations

> **Question 1:**
>
> 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 that would be appropriate for that purpose. What interval would be appropriate? How should PHMSA provide opportunities for stakeholder engagement in those reviews?

AGA supports the incorporation of explicit requirements for retrospective regulatory reviews at specified intervals to eliminate undue burdens and improve government efficiency. AGA recommends the following parameters for these retrospective regulatory reviews:

1. Reviews be performed consistent with DOT Order 210.6B, Section 11[3]
2. Review cycle interval not to exceed 10 years;
3. Review to include, at a minimum, PSRs not revised in at least 20 years;
4. Allowance for review and comment period for any PSRs proposed to be amended or rescinded, consistent with the requirements of the Administrative Procedure Act (APA)[4], or other applicable statute, regulation, or executive order..

[1] Founded in 1918, AGA represents more than 200 local energy companies committed to the safe and reliable delivery of clean natural gas to more than 180 million Americans. AGA is an advocate for natural gas utility companies and their customers and provides a broad range of programs and services for member natural gas pipelines, marketers, gatherers, international natural gas companies, and industry associates. Today, natural gas meets more than one third of the United States' energy needs.
[2] Docket ID PHMSA-2025-0050
[3] https://www.transportation.gov/sites/dot.gov/files/2025-03/Rulemaking%20Order%202100.6B%20Signed%203.10.2025.pdf

[4] *See* 5 U.S.C. §§ 551 – 559.

These parameters are prudent and justified, as they ensure harmonization and consistency with established DOT requirements for retrospective review (e.g., assessment of continued need, effectiveness, regulatory burden, etc.), they reduce the regulatory burden associated with petitioning for updated regulations, and they provide a proactive pathway for rescission of demonstrably obsolete and outdated Pipeline Safety Regulations (PSRs).

AGA proposes a new section (e.g., § 190.318) describing the requirements of PHMSA's retrospective regulatory review.

§ 190.318 Retrospective regulatory review of pipeline safety regulations.

(a) **Purpose.**
This section establishes the procedures by which the Pipeline and Hazardous Materials Safety Administration (PHMSA) shall conduct retrospective regulatory reviews of pipeline safety regulations (PSRs) under its authority, consistent with the principles of continuous regulatory improvement.

(b) **Review interval.**
PHMSA shall conduct a retrospective review of PSRs at least once every 10 years. These reviews shall be guided by the principles and requirements set forth in Section 11 of the Department of Transportation (DOT) Order 2100.6B, or any successor policy.

(c) **Scope of review.**

  (1) Retrospective reviews shall include, at a minimum, PSRs codified in 49 CFR parts 191 through 199 that have not been substantively revised in the preceding 20 years.

  (2) For purposes of this section, a "substantive revision" means a change that alters the regulatory requirements applicable to regulated entities, excluding clerical or administrative amendments.

(d) **Transparency.**
PHMSA shall publish a summary report of each retrospective review, including:

  (1) The regulations reviewed,

  (2) A description of the review process and stakeholder engagement,

  (3) The findings of the review, and

  (4) Any regulatory actions proposed or taken.

2. Oversight of State Authorities

> **Question 2:**
>
> 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.

AGA appreciates PHMSA's ongoing and thoughtful oversight of state pipeline safety authorities. While AGA member companies value their relationships with state authorities, considerable concern has been raised in recent years regarding misalignment between state-level pipeline safety priorities (e.g., rulemaking, enforcement) and those of PHMSA. PHMSA could improve government efficiency and reduce undue burdens by enhancing its oversight of state authorities to ensure greater alignment with federal safety objectives and regulatory intent. PHMSA currently delegates its enforcement authority to most, but not all, states.[5] In states where PHMSA delegates its authority to public utility commissions or other state-run regulatory authorities, PHMSA specifically says that States "…must adopt the minimum federal pipeline safety regulations; however, States may pass more stringent regulations for pipeline and underground natural gas storage through their State Legislatures."[6]

Growing "compliance deltas" between minimum Federal pipeline safety standards and State-level regulatory regimes have created significant challenges for operators, particularly those who operate in multiple states. While AGA acknowledges the authority of individual States to promulgate state-specific PSRs, this authority should not eclipse or circumvent PHMSA's primacy in researching and establishing a set of common and predominant PSRs across the United States. PHMSA employs measures to ensure regulations are thoroughly researched and technically sound prior to finalization. The authority delegated to the states to promulgate regulations would benefit from requiring a similar level of rigor and requirements as seen in the PHMSA rulemaking process as these state regulations carry the same compliance authority as regulations issued by PHMSA. If PHMSA's tone-setting role is ignored by state partners, it may create confusion and contradictions for operators, undermine PHMSA's authority, and largely defeat the purpose of PHMSA's approach to promulgating and developing a technically feasible, reasonable, cost-effective, and practicable compliance regime. Rulemaking processes at both the federal and state levels should be aligned and driven by sound engineering judgment, risk-based analysis, and in consideration of the

[5] Currently, pipeline safety enforcement in Alaska and Hawaii remain entirely under the purview of PHMSA. *See* U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, Federal/State Cooperative Agreements Map, NPMS, at 1 (June 2025), https://www.npms.phmsa.dot.gov/Documents/CoopAgreementsMap.pdf

[6] *See* Federal/State Legislative Authorities, Pipeline and Hazardous Materials Safety Administration (PHMSA), https://www.phmsa.dot.gov/working-phmsa/state-programs/federalstate-legislative-authorities.

technical feasibility, in order to provide safe, reliable, and cost-efficient energy to the communities served by natural gas operators.

To maintain a reasonable level of consistency in pipeline safety regulations, AGA recommends PHMSA evaluate state alignment with PHMSA's requirements and objectives when renewing certifications and agreements, and/or awarding grant funding. This evaluation would assess whether state regulations are consistent with PHMSA's risk-based framework, processes for promulgating regulations, and whether they impose additional unnecessary burdens. This approach would help promote regulatory consistency across jurisdictions, reduce needless costs, and ensure that federal funding support programs align with PHMSA's safety mission.

AGA recommends that PHMSA revise 49 CFR 198 to include performance factors for State pipeline safety programs based (in part) on national regulatory uniformity and measurable constraints on state-added rules. AGA proposes the following additions to § 198.13 (Evaluation of State pipeline safety programs) describing these criteria.

§ 198.13 Grant allocation formula.

…

(c) ~~The Administrator assigns weights to various performance factors reflecting program compliance, safety priorities, and national concerns identified by the Administrator and communicated to each State agency. At a minimum, the Administrator considers the following performance factors in allocating funds:~~ A State agency's pipeline safety program shall be evaluated annually for the purpose of determining its adequacy under 49 U.S.C. 60105 or 60106. The Administrator will consider the extent to which the State agency complies with the following performance factors, among others:

…

(9) The degree to which State-added rules or regulations promulgated under 49 U.S.C. 60105(a)(2) or 49 U.S.C. 60106(a)(2) are substantively harmonized with the applicable Federal pipeline safety regulations in parts 191 through 199 of this chapter. In evaluating harmonization, PHMSA will consider whether the State's additional requirements avoid unnecessary duplication or conflict, and align with federal safety objectives, terminology, structure, and ensure regulations are technically feasible, reasonable, cost-effective, and practicable.

(10) The extent to which the volume (and incremental cost/funding) of State-added rules exceeding those required by Federal pipeline safety regulations remains below a de minimis threshold, as determined periodically by PHMSA and based on risk of compliance disharmony, the burden posed in evaluating State program effectiveness, and national uniformity considerations. State programs exceeding this threshold without sufficient justification may be subject to corrective recommendations or reductions in grant eligibility.

AGA recommends similar changes to the PHMSA guidance document titled "Guidelines for State Participating in the Pipeline Safety Program"[7] for additional clarity. Section 3 of the document is titled "State Regulatory Responsibility". Section 3.1 generally states the requirements to adopt federal regulations and requirements. Section 3.1 also outlines that a state agency may issue additional or more stringent standards concerning intrastate pipelines if they are compatible with Federal regulations. For the reasons listed above, AGA recommends the following changes:

3.1 Adoption of Federal Regulations and Requirements

A State Agency participating in the pipeline safety program under a Certification is required to adopt Federal pipeline safety regulations or take steps to adopt such regulations. Adoption of applicable Federal regulations may be automatic, require State rulemaking actions, or necessitate State legislative action, and should be adopted within 24 months of the effective date or two general sessions of the State Legislature, whichever is longer. In addition, a state agency may issue additional or more stringent standards concerning intrastate pipelines if they are compatible with Federal regulations. Regulations adopted by the state agency shall avoid unnecessary duplication or conflict, align with federal safety objectives, terminology, structure, and ensure regulations are technically feasible, reasonable, cost-effective, and practicable. Any interpretation of a regulation adopted by a State Agency must not conflict with any opinion/interpretation issued by PHMSA.

For additional consideration, AGA also recommends that PHMSA evaluate permitting processes for actions required by the PSR. PHMSA should collaborate with the Council on Environmental Quality (CEQ) and relevant Federal and State authorities that have jurisdiction over air quality, biological resources, cultural and historic preservation, and water resources to identify regulatory frameworks, executive orders, policy changes or

7 https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2024-06/2024-State-Guidelines-with-Appendices-2023-12-18.pdf

court decisions impacting environmental permitting processes and develop streamlined, risk-based permitting pathways for activities under PHMSA's jurisdiction, especially those related to safety inspection, emergency repairs, and integrity management.[8]

In addition, there should be alignment with environmental review procedures with the revised NEPA framework to eliminate redundant or conflicting requirements. In 2024, the U.S. Court of Appeals for the District of Columbia ruled in *Marin Audubon Society vs. Federal Aviation Administration*, that the CEQ lacked the authority to promulgate NEPA regulations.[9] Further, Executive Order 14154 tasked CEQ with coordinating the revision of agency-led NEPA regulations for consistency with the NEPA statute and applicable case law.[10] Streamlined permitting and environmental reviews (for activities concerning safety related or immediate repair conditions, for example) will aid operators in making timely inspection and repair of pipelines to support public safety and welfare and safe and reliable delivery of the pipeline product, while avoiding harm to the environment.

Coordination with state agencies concerning state permitting and environmental review requirements will also be necessary. Clear, consistent guidance for operators navigating multi-agency permitting processes would benefit timely approvals for projects that are essential to public safety and environmental protection.

By taking these steps, PHMSA can help reduce regulatory friction and improve interagency coordination so that its safety mission is not hindered by procedural inefficiencies. This approach would also support the goals of a recent Executive Order aimed at modernizing infrastructure permitting and unleashing American energy, while maintaining protective environmental safeguards.

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[8] Examples of federal agencies include the Department of Interior [US Fish & Wildlife, National Marine Fisheries Service, National Park Service, Bureau of Land Management, etc.], Department of Agriculture [US Forest Service, etc.], Department of Defense [US Army Corps of Engineers, etc.].

[9] *Marin Audubon Society v. Fed. Aviation Admin*, No. 23-1067 (D.C. Cir. 2024) (holding that the Council on Environmental Quality (CEQ) lacks authority to promulgate binding regulations under NEPA and vacating the FAA's air tour management plan for failing to conduct a proper environmental analysis).

[10] AGA notes that the Department of Transportation, on July 3, 2025, revised its agency-specific NEPA procedures. These procedures also apply to numerous DOT Operating Administrations, including PHMSA.

3. Small Business Impact

Question 3: 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?

AGA notes that many of our members are small businesses with fewer than 1,000 employees. AGA recognizes the vital role these small operators play in the industry and the communities they serve. Therefore, it is crucial to PHMSA to continue to consider disproportionate regulatory burdens on small operators. Resource-intensive programs (e.g., Integrity Management, Control Room Management, Operator Qualification, etc.) impact small operators particularly hard. The comparatively small number of pipeline miles, service lines, or employees does not preclude small operators from having to implement programs that have the same level of sophistication as those of larger operators. We recommend that PHMSA develop additional guidance specifically tailored to small operators and ensure that new regulations are scalable to minimize economic impact on smaller operators.

AGA notes that many of our members qualify as small businesses under the Small Business Administration's definition, with fewer than 1,000 employees. These operators play a critical role in delivering safe, reliable natural gas service to millions of customers and supporting the communities they serve.

AGA supports PHMSA continuing to evaluate and mitigate disproportionate regulatory burdens on small operators. Current resource-intensive programs - such as Integrity Management (IM), Control Room Management (CRM), and Operator Qualification (OQ) - pose significant challenges for small entities. While these programs are essential for safety, their prescriptive nature often requires the same level of sophistication, documentation, and technology investment as that of large operators, despite small operators managing fewer pipeline miles, service lines, and employees.

To address this imbalance, AGA recommends that PHMSA:

1. **Develop tailored guidance for small operators** that clarifies compliance expectations and provides practical implementation strategies.
2. **Ensure scalability in new regulations**, allowing requirements to be risk-based and proportionate to system size, complexity, and operating environment.
3. **Consider alternative compliance pathways**, such as simplified integrity management plans or performance-based options for low-risk systems, to maintain safety while reducing unnecessary economic impact.

These steps will help PHMSA achieve its safety objectives while supporting the long-term viability of small operators that are essential to the nation's energy infrastructure.

4. Special Permits

Question 4:

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.

AGA supports PHMSA's recent Notice of Proposed Rulemaking, entitled "Pipeline Safety: Rationalize Special Permit Conditions."[11] It is appropriate for PHMSA to clarify and simplify the conditions of special permits promulgated under 49 CFR 190.341, and AGA encourages PHMSA to expeditiously finalize this rulemaking as proposed in the NPRM.

[11] Pipeline Safety: Rationalize Special Permit Conditions, Federal Register Vol. 90, No. 124 (July 1, 2025).

5. National Environmental Policy Act (NEPA) Compliance

> **Question 5:**
>
> 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 exclusions. Are there any categorical exclusions employed by other Federal agencies that PHMSA should adopt pursuant to 42 U.S.C. 4336c?

AGA supports PHMSA's ongoing review of NEPA compliance practices to ensure they do not impose undue burdens. While PHMSA's compliance practices related to NEPA may not specifically place an undue burden on stakeholders, compliance related regulations from other Federal and State agencies can create significant challenges in meeting PHMSA deadlines due to environmental review and permitting hurdles. Recently, PHMSA adopted a categorical exclusion (CATEX) from the Department of Energy (DOE) for the repair and replacement of pipelines. AGA urges PHMSA to continue to evaluate and, where appropriate, adopt other agencies' CATEXs to expedite the environmental review and permitting process. PHMSA should also continue to coordinate and collaborate with other agencies to help remove permitting bottlenecks and expedite the permitting of projects associated with energy products transported via pipeline.[12]

6. User Fees

> **Question 6:**
>
> 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.

AGA recommends that PHMSA provide greater transparency in how annual user fees (49 U.S.C. 60301 et seq.) are determined and applied to provide operators with information regarding services provided under the fees. PHMSA should also provide a detailed schedule of the cost of activities employed in the fee calculation to determine the approximate rate per transmission mile, which would allow operators to estimate the

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[12] Examples of regulatory agencies where PHMSA engagement may be helpful include, but are not limited to, the US Army Corps of Engineers, US Fish & Wildlife Service, US Park Service, US Forest Service and Bureau of Land Management, amongst others.

approximate PHMSA annual user fees for budget planning. AGA further recommends that PHMSA consider the impact of fee increases on small operators and provide more predictable fee structures.

7. Incorporation of Interpretations, Approvals, or Special Permits

> **Question 7:**
>
> 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?

AGA supports PHMSA's new process for providing stakeholder transparency and soliciting input on interpretation requests[13], and recommends amending 49 CFR 190.11 to codify the mechanism for obtaining stakeholder input and feedback on written interpretation requests.

B. Pipeline Safety Regulations

1. Compliance Burdens

> **Question 1:**
>
> 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 are adequately addressed by other PSR requirements?

Continuing Surveillance

AGA recommends revising § 192.613 (Continuing Surveillance) to eliminate redundancy with Distribution Integrity Management Program (DIMP) regulations, which already mandate continuous monitoring and risk analysis. The current regulation was written before the advent of the comprehensive integrity management framework found in DIMP and relies on generalized procedures for surveillance without requiring operators to assess risk, prioritize threats, or document decision-making. DIMP regulations under Subpart P fill these gaps. This recommendation is supported by the justification that DIMP is data-driven and risk-based, aligning better with the natural gas industry's voluntary adoption of

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[13] PHMSA, Pending Pipeline Interpretations. https://www.phmsa.dot.gov/standards-rulemaking/pipeline/interpretations/pending-pipeline-interpretations

Safety Management Systems (API RP 1173). Retiring portions of § 192.613 would reduce regulatory complexity, streamline compliance obligations, and shift focus toward performance-based outcomes. Specifically, AGA recommends striking § 192.613(a) & (b) and renaming § 192.613 "Surveillance After Extreme Weather or Natural Disaster".

§192.613 ~~Continuing surveillance~~ <u>Surveillance After Extreme Weather or Natural Disaster</u>

~~(a) Each *operator* shall have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions.~~

~~(b) If a segment of *pipeline* is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to recondition or phase out the segment involved, or, if the segment cannot be reconditioned or phased out, reduce the maximum allowable operating *pressure* in accordance with §192.619 (a) and (b).~~

~~(c)~~ ~~(a)~~ Following an extreme weather event or natural disaster that has the likelihood of damage to pipeline facilities by the scouring or movement of the soil surrounding the pipeline or movement of the pipeline, such as a named tropical storm or hurricane; a flood that exceeds the river, shoreline, or creek high-water banks in the area of the pipeline; a landslide in the area of the pipeline; or an earthquake in the area of the pipeline, an operator must inspect all potentially affected onshore transmission pipeline facilities to detect conditions that could adversely affect the safe operation of that pipeline.

~~(1)~~ (a) An operator must assess the nature of the event and the physical characteristics, operating conditions, location, and prior history of the affected pipeline in determining the appropriate method for performing the initial inspection to determine the extent of any damage and the need for the additional assessments required under this paragraph (a) ~~(c)(1)~~.

…

Uprating

Another provision of the Pipeline Safety Regulations (PSR) that imposes an undue burden without delivering a commensurate safety benefit relates to an interpretation of the requirement of strength testing pipelines under 49 CFR § 192.557, which governs uprating pipelines to less than 30% of specified minimum yield strength (SMYS):

Question: In uprating steel pipelines operated at 100 psi, or more, with hoop stresses less than 30 percent of SMYS, must the pressure be increased in the increments required to the desired maximum allowable operating pressure times the appropriate factor in the table in Section 192.619(a)(2)(ii)?

OPS Interpretation: . . ."Subject to the requirements of Section 192.621, the maximum allowable operating pressure (MAOP) for the pipelines to which you refer may not be increased above the lowest pressure determined in accordance with Section 192.619(a). In uprating to a pressure permitted by Section 192.619(a)(2)(ii), a strength test must be performed. The increments prescribed by Section 192.557(c) apply to the increase in pressure between the existing MAOP and the test pressure or the desired MAOP multiplied by the appropriate factor in Section 192.619(a)(2)(ii}.

The original intent of the regulation was to allow operators to uprate pipelines without requiring a new pressure test, providing all other criteria in the section were met. However, PHMSA's 1974 advisory bulletin and subsequent interpretations have introduced ambiguity by referencing § 192.619(a)(2), which governs strength testing, and suggesting that a pressure test is required even for low-stress uprating scenarios.

PHMSA's own interpretation in PI-74-0141[14] acknowledged that this was "an overstatement of the requirement" and clarified that a "leak test" is appropriate for pipelines subject to § 192.557. The bulletin outlined three acceptable forms of pressure testing, including one method (Example 3) in which pressure is incrementally increased and maintained with the pressure source connected, a process that aligns with the incremental uprating procedure already required by § 192.557.

While some stakeholders interpret this guidance to mean that the pressure test can be conducted in conjunction with the incremental uprating process (as in Example 3), the lack of clarity in the advisory bulletin has led to inconsistent application and, in some cases, duplicative testing requirements. This ambiguity creates unnecessary procedural burdens, particularly for low-stress pipelines where the safety benefit of a separate strength test is minimal.

PHMSA's 1977 response in PI-77-0108[15] further supports the need for reform, acknowledging that the current requirements may impose unnecessary restrictions on lateral transmission lines and committing to future review.

AGA recommends that PHMSA revise its advisory bulletin to clearly state that the incremental pressure increase process outlined in § 192.557, particularly when conducted in a manner consistent with Example 3, satisfies the intent of a pressure test. This clarification would eliminate confusion, reduce redundant testing, and allow operators to focus resources on higher-risk activities that yield greater safety benefits.

[14] PHMSA Interpretation Response #PI-74-0141
[15] PHMSA Interpretation Response #PI-77-0108

2. Definitions

> **Question 2:**
>
> 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.

Transmission Line

AGA suggests clarifying the definition of "transmission line" to reduce confusion and operational burden, align the definition with decades-long industry practices, and clearly enable operators to manage pipeline systems at a segment level.

Pipelines and pipe segments operating below 20% SMYS are at a much lower risk of developing a rupture (or sometimes a propagating fracture) as opposed to a "leakage" failure.[16] The type and amount of safety measures applied to pipelines on opposing ends of the 20% SMYS threshold should align with both the likelihood and consequence of a risk event. Pipelines operating at or above 20% SMYS, and particularly those operating at 30% SMYS or higher, are at higher risk of developing a rupture. For these pipelines, it is appropriate that operators complete more rigorous safety and risk reduction measures (e.g., integrity assessments and remediations). Conversely, pipelines operating at lower stress levels may not warrant the same level of activity or expenditure, given their lower likelihood of rupture. This risk-based approach is consistent with existing regulatory frameworks. For example, 49 CFR § 192.941 acknowledges the distinction between pipelines operating at or above 30% SMYS and those at or above 20% SMYS by allowing a "low-stress reassessment" method.

Should PHMSA adopt a threshold for the designation of transmission pipelines based solely on the 20% SMYS criterion, operators would be able to leverage the requirements in 49 CFR Part 192, Subpart P (Distribution Integrity Management Program) to assess pipeline conditions and take appropriate, risk-informed actions. This would enable continued safe operation while aligning safety measures with actual risk levels, which

[16] *See* B.N. Leis et al., Leak Versus Rupture Considerations for Steel Low-Stress Pipelines, Battelle Final Report GRI-00/0232, at 32 (Jan. 2001): *Given the results generated, the leak to rupture transition for corrosion defects in the low-wallstress pipeline system can be taken as 30 percent of SMYS, a value that is conservative in comparison with in-service incidents. Thresholds for the transition from leak to rupture also were evaluated for immediate as well as delayed mechanical damage incidents with reference to fullscale test data, incident data, and mechanics and fracture analysis. Full-scale test data indicated this threshold was in excess of 30 percent of SMYS, the lowest threshold identified for rupture due to corrosion, whereas the steels represented in reportable incidents possess toughness [sic] indicated a threshold on order of 25 percent of SMYS.*

aligns with "OPS's risk-based approach to protecting the public, property, and the environment."[17]

Moreover, AGA notes that PHMSA has expressly distinguished *"piping"* operating at or above 20 percent SMYS in its RIN 2 definition of "transmission line."[18] AGA has long supported[19] PHMSA's considered use of the term "piping," as it has allowed operators to appropriately demarcate these segments as transmission lines, distinct from other downstream (or upstream) piping operating at less than 20 percent SMYS. Alternative interpretations of "transmission line" criteria would unnecessarily increase the mileage of transmission pipelines (as well as requisite HCA, MCA, Class 3, and Class 4 mileage) by orders of magnitude, with uncertain net safety benefits.

Likewise, AGA notes that PHMSA's definition of "distribution center" as "piping used to deliver gas to customers for end use"[20] could be wrongly interpreted to exclude everything except the piping directly upstream of the customer's meter. Such a narrow reading of the "distribution center" definition has the potential to reclassify anything upstream of a service regulator as transmission pipeline. A site's status as a "distribution center" – and therefore the status of its upstream piping as "transmission line" – cannot be based on a subjective view of where and if "end use" is occurring at any given moment in time.

Clearly, streamlining the designation of transmission pipelines has the benefit of reducing the variation in interpretations of what constitutes a transmission pipeline. As evidenced by the interpretation requests posed to PHMSA, including a more recent request by the Pennsylvania Public Utility Commission[21], there are administrative burdens to operators, state agencies, and PHMSA to manage the designation of transmission vs. distribution pipelines beyond the knowledge of an operator's pipeline characteristics.

Finally, PHMSA should eliminate the words "connected series of pipelines" from the definition of transmission line. As stated previously in an AGA Petition for Reconsideration[22] the inclusion of this phrase "would not allow a reasonable operator to be able to determine the extent of applicable regulatory obligations under [RIN 2] – and under EPA's greenhouse gas reporting rules for the natural gas industry (40 C.F.R. Part 98,

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[17] PHMSA Memorandum: "Inspection and Enforcement Priorities," July 17, 2025, at 6; https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2025-07/PHMSA%20OPS%20Inspection%20and%20Enforcement%20Priorities%20Memo.pdf

[18] "Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments." 87 FR 52224. August 24, 2022.

[19] Commentary on the Delineation of Distribution Facilities and Transmission Lines, American Gas Association; September 20, 2024.

[20] "Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments." 87 FR 52224. August 24, 2022.

[21] In March of 2024, the PAPUC requested clarification from PHMSA to determine whether several pipeline configurations met the definition of "transmission." The interpretation letter has been removed from PHMSA's Letters of Interpretation website pending a review by PHMSA.

[22] Petition For Reconsideration – Docket No. PHMSA-2011-0023, American Gas Association; September 23, 2022.

Subpart W); moreover, the phrase "or connected series of pipelines" was not included in PHMSA's NPRM and its addition generated limited discussion during the subsequent GPAC meeting. Most problematically, the phrase suggests that every permutation of a connected series of transmission lines is itself a distinct transmission line – potentially requiring operators to demonstrate compliance with any 49 CFR 192 requirement applicable to a "transmission line" (singular) for a vast number of interconnected combinations involving a single pipeline.

PHMSA should revise the current definition of transmission line to support a clearer, more streamlined, and more explicitly risk-based means of classifying and delineating pipeline systems. The recommendation below would reduce confusion, lower costs for operators and ratepayers, and maintain high safety standards for lower-stress pipelines.

§192.3 Definitions

As used in this part:

...

Transmission line means a pipeline,~~ or connected series of pipelines,~~ other than a gathering line, that:

~~(1) Transports gas from a gathering pipeline or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center;~~

~~(2)~~(1) Has an MAOP of 20 percent or more of SMYS; or

~~(3) Transports gas within a storage field; or~~

~~(4)~~(2) Is voluntarily designated by the operator as a transmission pipeline.

Note 1 to *transmission line*. <u>An operator may segment a pipeline and classify each contiguous segment in accordance with its respective MAOP as a percentage of SMYS.</u> ~~A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas~~

Application of Class Location Designations

Class Location regulations have remained unchanged since their implementation in the 1970s. Current code regulations require the identification and assignment of both Class Location and Consequence Areas (High or Moderate) for Transmission pipeline segments. Designation of both Class Location and Consequence Area categories often results in an overlap of many Class 3 and Class 4 segments with High Consequence Area (HCA) identified segments. This also creates duplicative work in tracking and reporting efforts for compliance with both requirements.

Class Location changes can also trigger additional studies resulting in pipeline replacements or pressure reductions[23] for segments which may be lower risk. PHMSA should consider using one designation process – Consequence Areas – moving forward. While Class Location may drive increased cadences in pipeline surveys, it is based largely upon population counting and may not accurately account for actual potential impacts from identified threats and risks. The use of Consequence Areas instead of Class Locations to drive inspections and maintenance of the pipeline would maintain safety by focusing resources and investments on higher risk segments. This also aligns with the Interstate Natural Gas Association of America's (INGAA) proposal of an alternative concept to Class Location altogether. INGAA noted that PHMSA's newly modified integrity management requirements and the use of HCA/MCAs were a more efficient means to managing pipeline safety than following two separate processes for categorizing and maintaining pipelines.[24]

One operator incurred approximately $150 million in cumulative costs for Class Location Survey and Remediation over a five-year period ending in 2024. This is based on the number of hours spent on annual surveys, hours spent on Class Location Studies and valve spacing reviews, and costs for completion of remediation projects. This does not include costs associated with other requirements that are driven by class location.

AGA recommends PHMSA remove class location from the PSR and update the following CFR sections to replace class location with consequence area as a factor and/or reference as appropriate:

Section	**Reference**
49 CFR §192.5 - Class locations.	All
49 CFR §192.8 - How are onshore gathering pipelines and regulated onshore gathering pipelines determined?	(a)(1)(5), (c)(2)
49 CFR §192.9 - What requirements apply to gathering pipelines?	(c), (f)(1)(ii), (g)(3) & (5)
49 CFR §190.341 - Special permits.	(f)(1)(v)(B)
49 CFR §192.111 - Design factor (F) for steel pipe.	(a-d)

[23] 49 CFR §§ 192.609, 192.610, & 192.611

[24] INGAA Comments in Response to DOT-OST-2025-0026 ("Ensuring Lawful Regulation; Reducing Regulation and Controlling Regulatory Costs" RFI: https://www.regulations.gov/document/DOT-OST-2025-0026-0001)

49 CFR §192.121 - Design of plastic pipe.	(b)(ii)
49 CFR §192.150 - Passage of internal inspection devices.	(b)(6)
49 CFR §192.167 - Compressor stations: Emergency shutdown.	end note with reference to (C)(2)(ii)
49 CFR §192.179 - Transmission line valves.	(a)(1-4), (e), (f), (h)(1-3)
49 CFR §192.243 - Nondestructive testing.	(d)(1-3)
49 CFR §192.327 - Cover.	(a)
49 CFR §192.452 - How does this subpart apply to converted pipelines and regulated onshore gathering pipelines?	(b) & (c)
49 CFR §192.503 - General requirements.	Subpart J / (c)
49 CFR §192.505 - Strength test requirements for steel pipeline to operate at a hoop stress of 30 percent or more of SMYS.	Subpart J / (a) & (b)
49 CFR §192.555 - Uprating to a pressure that will produce a hoop stress of 30 percent or more of SMYS in steel pipelines.	(d)(2)
49 CFR §192.609 - Change in class location: Required study.	All
49 CFR §192.610 - Change in class location: Change in valve spacing.	All
49 CFR §192.611 - Change in class location: Confirmation or revision of maximum allowable operating pressure.	All
49 CFR §192.613 - Continuing surveillance.	(a)
49 CFR §192.614 - Damage prevention program.	(d)(2)
49 CFR §192.619 - Maximum allowable operating pressure: Steel or plastic pipelines.	(a)(2)(ii)
49 CFR §192.620 - Alternative maximum allowable operating pressure for certain steel pipelines.	(a)(1) & (a)(2)(ii) & (c)(8)
49 CFR §192.624 - Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines.	(a)(1)(ii), (a)(2)(ii), (c)(1)(i), (c)(2), (c)(5)(ii)
49 CFR §192.625 - Odorization of gas.	(b)(1), (b)(3)

49 CFR §192.634 - Transmission lines: Onshore valve shut-off for rupture mitigation.	(a), (b)(1), (b)(2)(i-ii)
49 CFR §192.636 - Transmission lines: Response to a rupture; capabilities of rupture-mitigation valves (RMVs) or alternative equivalent technologies.	(g)
49 CFR §192.705 - Transmission lines: Patrolling.	(b)
49 CFR §192.706 - Transmission lines: Leakage surveys.	(a) & (b)
49 CFR §192.707 - Line markers for mains and transmission lines.	(b)(2-4)
49 CFR §192.710 - Transmission lines: Assessments outside of high consequence areas.	(a)(1) & (b)(1)
49 CFR §192.714 - Transmission lines: Repair criteria for onshore transmission pipelines.	(c)(1-2), (d)(2)(iv-vii), (d)(3)(v-vi), (e)(1)(ii)
49 CFR §192.903 - What definitions apply to this subpart?	(1)(i-v)
49 CFR §192.917 - How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?	(b)(1)(xix)
49 CFR §192.929 - What are the requirements for using Direct Assessment for Stress Corrosion Cracking?	(b)(4)(ii)
49 CFR §192.933 - What actions must be taken to address integrity issues?	(a)(1)(i)(B), (d)(2)(iv - vii), (d)(3) (v & vi)
49 CFR §192.935 - What additional preventive and mitigative measures must an operator take?	(d)
49 CFR §192.939 – Reassessment intervals	by reference to 192.917
49 CFR §192.905 – Identification of high consequence areas	by reference to §192.903
49 CFR §192.921 – Integrity assessment methods	by reference to §192.917, subpart J
49 CFR §192.937 – Continuing integrity evaluation	by reference to 192.917, 192.929, 192.933, 192.935.

Definition of an Incident

AGA suggests clarifying the definition of "Incident". "Incident" as it is currently defined includes events that are "significant in the judgment of the operator," is vague and allows for considerable regulatory interpretation and second-guessing. Removing this section of "incident" definition would not reduce safety and would provide additional consistency for operators and state regulators. The revised definition also would lead to less interpretive regulatory conflict and unnecessary reporting of marginal accidents, which incur a cost on the operator to gather the data and report.

The following clarifying language is recommended:

§191.3 Definitions

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.

(2) An event that results in an emergency shutdown of an LNG facility or a UNGSF. Activation of an emergency shutdown system for reasons other than an actual emergency within the facility does not constitute an incident.

~~(3) An event that is significant in the judgment of the operator, even though it did not meet the criteria of paragraph (1) or (2) of this definition.~~

3. Gathering Line Regulations

Question 3:
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.

AGA defers to the recommendations of other trade associations (i.e., INGAA and GPA Midstream) and operators that are directly impacted by gathering line regulations for responses to this question.

4. Reporting and Notification Requirements

Question 4:
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, as well as the technical, safety, and economic reasons supporting those recommended amendments.

Incident Reporting Timeline

Reporting incidents with multiple unknowns as soon as 30 days (not including weekends or holidays) poses an undue burden to natural gas operators. Incident investigations are often complicated processes involving multiple stakeholders working in concert to determine the timeline of events and, ultimately, the root cause (or causes) of the incident. Often, especially when third-party investigation is required, 30 days is simply not enough time to complete a thorough investigation and finalize reporting or incident details. Consequently, operators are required to submit supplemental incident reports to clarify or correct unknown or speculative data; often, these supplemental reports are filed within 60 days of the initial 30-day incident reporting deadline established in §191.9.

An estimate of incident report submittals suggests that since 2010 there have been 174 supplemental gas distribution incidents reports submitted between 31 days and 90 days from detection, accounting for roughly 11% of the total number of incident reports submitted. Similarly, for gas transmission/gathering/LNG/UNGS, there have been 160 supplemental reports submitted between 31 and 90 days, accounting for 8% of total incident reports.

	Supplemental Reports Submitted (between 31 and 90 days from Incident Detection	Estimated Reporting Burden (Hours)[25]	Estimated Reporting Burden ($)	Estimated ANNUAL Reporting Burden ($)
Gas Distribution (Form RSPA F 7100.1)	174	609	$24,360	$1,624
Gas Transmission / Gathering / LNG / UNGS (Form PHMSA F 7100.2)	160	560	$22,400	$1,400

Reporting fragmentary incident data within 30 days creates an unnecessary reporting burden with negligible safety benefit. AGA suggests providing operators with 90 days (from detection of an incident) to submit an incident report.

§191.9 Distribution system: Incident report.

(a) Except as provided in paragraph (c) of this section, each *operator* of a distribution *pipeline* system shall submit Department of Transportation Form RSPA* F 7100.1 as soon a practicable but not more than ~~30~~ 90 days after detection of an *incident* required to be reported under §191.5.

…

§191.15 Transmission systems; gathering systems; liquefied natural gas facilities; and underground natural gas storage facilities: Incident report.

(a) Pipeline systems—

(1) *Transmission, offshore gathering, or regulated onshore gathering*. Each operator of a transmission, offshore gathering, or a regulated onshore gathering pipeline system must submit Department of Transportation (DOT) Form PHMSA F 7100.2 as soon as practicable but not more than ~~30~~ 90 days after detection of an incident required to be reported under § 191.5.

(2) *Reporting-regulated gathering.* Each operator of a reporting- regulated gathering pipeline system must submit DOT Form PHMSA F 7100.2-2 as

[25] Pipeline Safety: Information Collection Activities. Federal Register Vol. 90, No. 133 (July 15, 2025). Reporting burden assumes 3.5 hours per incident report, and a labor cost of $40 per hour.

soon as practicable but ~~30~~ 90 days after detection of an incident required to be reported under § 191.5 that occurs after May 16, 2022**.**

(b) LNG. Each operator of a liquefied natural *gas* plant or facility must submit DOT Form PHMSA F 7100.3 as soon as practicable but not more than ~~30~~ 90 days after detection of an incident required to be reported under § 191.5 of this part.

(c) *Underground natural gas storage facility*. Each operator of a *UNGSF* must submit DOT Form PHMSA F7100.2 as soon as practicable but not more than ~~30~~ 90 days after the detection of an incident required to be reported under § 191.5.

…

With respect to reporting requirements, PHMSA has also recently issued a Direct Final Rule (Pipeline Safety: Adjust Annual Report Filing Timelines; Docket number 2025-0108) which will update reporting deadlines for § 191.11 (Distribution Annual reports) and § 191.17 (Transmission, LNG and Underground Storage Annual reports) from March 15 to June 15 of each calendar year. AGA supports this DFR and its objective of reducing regulatory reporting burden and aligning with existing requirements for hazardous liquids pipelines. However, PHMSA should provide the same extension for National Pipeline Mapping System (NPMS) updates required by § 191.29. The data needed for reporting of LNG and Transmission assets via NPMS and annual reports are very closely integrated. Operators must validate and confirm that any and all changes are accurately reflected in both systems, and that details and mileage agree for transmission pipelines and LNG assets submitted in each system by operator ID. Because these two reporting requirements cover the same cumulative pipeline assets, the two reporting deadlines should be aligned.

§ 191.29 National Pipeline Mapping System.

…

(b) The information required in paragraph (a) of this section must be submitted each year, on or before ~~March~~ June 15, representing assets as of December 31 of the previous year. If 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.

5. Consensus Industry Standards

Question 5:

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.

AGA supports incorporating updated editions of industry standards by reference to improve regulatory efficiency and reduce undue regulatory burdens. Industry standards are regularly updated based on studies performed, advancements in technology, and event lessons learned. Therefore, updating regulatory standards to the latest version in a timely manner is not only efficient, but it also provides tremendous safety value.

While this rulemaking may serve as a one-time effort to update 49 CFR § 192.7 to incorporate by reference the most up to date standards, PHMSA should also implement a more effective and efficient means by which updates can be made in the future. PHMSA should consider adopting an approach whereby PHMSA provides a detailed analysis of the specific differences between the standard currently incorporated by reference and the edition being proposed for incorporation. Where applicable, this analysis can be limited to the specific sections of the industry consensus standard that is incorporated by reference. This approach would eliminate the regulatory burden of standard revision adoptions and would ensure that all stakeholders are aligned on, and aware of, the "compliance delta" associated with incorporating the new edition by reference.

AGA recommends adoption of the latest edition of ASTM F2620 referenced in 49 CFR §§ 192.281(c) and 192.285(b)(i). § 192.7 currently references ASTM F2620-19 for heat fusion joints, whereas this standard has since been updated to version ASTM F2620-20ae2. The latest version of ASTM F2620 is the result of extensive work from industry subject matter experts and incorporates updated visual acceptance criteria based on the properties of modern bimodal polyethylene pipe.

AGA further recommends incorporating by reference ASTM F3565-23 *Standard Practice for Electrofusion Joining Polyethylene (PE) Pipe and Fittings for Pressure Pipe Service.* Where ASTM F2620 provides an industry standard for certain types of heat fusion joints, 49 CFR §§ 192.281 and 192.285 have yet to adopt an industry standard for electrofusion joints. ASTM F3565-23 is ASTM F2620's equivalent for electrofusion joints. This adoption will align the industry to one standard for electrofusion processes, removing the current ambiguity in regulation, which allows for variations in procedures and practices.

Suggested regulatory language for the incorporation by reference of ASTM F2620-20ae2 and ASTM F3564-23 can be found in later discussion on revisions to subpart F in the suggested amendments to §§ 192.281 and 192.285

AGA also recommends the incorporation by reference of ASME PCC-2-2022 *Repair of Pressure Equipment and Piping*. This industry consensus standard provides necessary design basis requirements for repair methods used for equipment and piping after having been placed into service. ASME PCC-2-2022 compliments ASME B31.8S-2018 (currently incorporated by reference) and provides operators flexibility when determining appropriate repair methods. The incorporation of this standard is discussed in greater detail in the section of this document outlining suggested revisions to § 192.715(c).

6. Material, Design, Testing, and Construction Requirements

Question 6:

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.

Revisions to Subpart C:

AGA suggests §§ 192.107 and 192.109 be amended to allow operators the option to use methods that are currently deemed appropriate for the verification of material attributes of transmission lines (§192.607) to determine the wall thickness and yield strength of steel pipe of unknown specification or properties.

Both §§ 192.107 and 192.109 add unnecessary and arbitrary conservatism to pipe strength and pipe nominal wall thickness determined through testing. Modern lab and field (in situ) testing for these properties is precise, accurate, and has well-defined uncertainties. As such, allowing operators the option to leverage these methodologies to determine the yield strength and wall thickness of pipe would enable operators to more efficiently transport gas for customers, reducing the need for costly projects to increase system capacity. PHMSA has asserted that the requirements stated in § 192.607 are sufficiently conservative for operators to confirm properties of transmission lines, which generally carry more regulatory requirements than other types of pipeline. Operators should be afforded the option to employ methods deemed appropriate for these pipelines to other pipelines that are generally less strictly regulated. Additionally, the requirements of § 196.607 were adopted in 2019 – which is significantly more recent than the latest amendments to §§ 192.107 and 192.109, which occurred in 1998. The requirements of § 192.607 account for technologies that were either not available or considerably less advanced when §§ 192.107 and 192.109 were last amended.

§ 192.107 Yield strength (*S*) for steel pipe.

(a) For pipe that is manufactured in accordance with a specification listed in section I of appendix B of this part, the yield strength to be used in the design formula in § 192.105 is the SMYS stated in the listed specification, if that value is known.

(b) For pipe that is manufactured in accordance with a specification not listed in section I of appendix B to this part or whose specification or tensile properties are unknown, the yield strength to be used in the design formula in § 192.105 is one of the following:

(1) If the pipe is tensile tested in accordance with section II-D of appendix B to this part, the lower of the following:

(i) 80 percent of the average yield strength determined by the tensile tests.

(ii) The lowest yield strength determined by the tensile tests.

(2) If tensile properties of the pipe are established in accordance with procedures that satisfy the requirements of § 192.607, the resulting yield strength determined by those procedures.

(3) If the pipe is not tensile tested as provided in paragraph (b)(1) or (b)(2) of this section, 24,000 psi. (165 MPa).

§ 192.109 Nominal wall thickness (t) for steel pipe.

(a) If the nominal wall thickness for steel pipe is not known, it is determined by ~~measuring the thickness of each piece of pipe at quarter points on one end~~. using one of the following methods:

(1) By measuring the thickness of each piece of pipe at quarter points on one end. However, if the pipe is of uniform grade, size, and thickness and there are more than 10 lengths, only 10 percent of the individual lengths, but not less than 10 lengths, need to be measured. The thickness of the lengths that are not measured must be verified by applying a gauge set to the minimum thickness found by the measurement. The nominal wall thickness to be used in the design formula in §192.105 is

the next wall thickness found in commercial specifications that is below the average of all the measurements taken. However, the nominal wall thickness used may not be more than 1.14 times the smallest measurement taken on pipe less than 20 inches (508 millimeters) in outside diameter, nor more than 1.11 times the smallest measurement taken on pipe 20 inches (508 millimeters) or more in outside diameter.

(2) By using procedures that satisfy the requirements of § 192.607 to determine nominal wall thickness.

Revisions to Subpart F:

AGA further suggests revising 49 CFR § 192.285 to provide clarification of that section's applicability to plastic fusion joints, and not all plastic joints. Currently, § 192.285(b)(1) requires all plastic joint specimens used in qualifying persons to make joints to be visually examined during and after joining, and that visual examination be compared to photographs of acceptable joints. Additional code sections (§§ 192.273 and 192.287) apply more broadly to plastic joint inspections overall, which therefore could be interpreted to require a visual examination (compared to photographs of acceptable joints) of all plastic joints during and after assembly.

When looking further into the applicability of these sections for all plastic joints, a discrepancy exists between plastic fusion joints and plastic mechanical joints. Plastic fusion joint and equipment manufacturers have robust specifications and instructions, which include images of acceptable fusion joints and detailed visual acceptance criteria of completed joints. Similar images and details exist for plastic fusion joints in industry standards such as ASTM F2620 and ASTM F3565. In contrast, plastic mechanical joints lack such detail. Manufacturers' specifications provide detailed steps related to the process of joining, but little to no instruction on what criteria should be placed on a final plastic mechanical joint for visual inspection, nor photographs or images of visually acceptable plastic mechanical joints. Additionally, no industry standards exist for plastic mechanical joints which provide such guidance. This has left the industry with no standard approach to the application of §§ 192.285(b)(1), 192.273, and 192.287 as it relates to plastic mechanical joints.

PHMSA should first clarify the intention of these sections, in terms of inspection expectations and joint type applicability. Additionally, AGA suggests revised regulatory text as follows:

§ 192.281 Plastic pipe

…

(c) *Heat-fusion joints*. Each heat fusion joint on a PE pipe or component, except for electrofusion joints, must comply with ASTM F2620 (incorporated by reference in § 192.7), or an alternative written procedure that has been demonstrated to provide an equivalent or superior level of safety and has been proven by test or experience to produce strong gastight joints, and the following:

…

(3) An electrofusion joint must comply with ASTM F3565 (incorporated by reference, see § 192.7), or an alternative written procedure that has been demonstrated to provide an equivalent or superior level of safety and has been proven by test or experience to produce strong gastight joints. ~~be made using the equipment and techniques prescribed by the fitting manufacturer, or using equipment and techniques shown, by testing joints to the requirements of § 192.283(a)(1)(iii), to be equivalent to or better than the requirements of the fitting manufacturer.~~

§192.285 Plastic pipe: Qualifying persons to make joints.

…

(b): The specimen joint must be:

(1) Visually examined during ~~and after~~ assembly or joining ~~and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure~~; ~~and~~

(2) In the case of heat fusion joints: visually examined after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and

(~~2~~3) In the case of a heat fusion, solvent cement, or adhesive joint:

(i) Tested under any one of the test methods listed under § 192.283(a), and for PE heat fusion joints ~~(except for electrofusion joints)~~ visually inspected in accordance with ASTM F2620, ASTM F3565 (incorporated by reference, see § 192.7), or a written procedure that has been demonstrated to provide an equivalent or superior level of safety, applicable to the type of joint and material being tested;

...

Revisions to Subpart I

AGA also recommends that PHMSA amend §§ 192.465(d), 192.465 (f)(2), and 192.473(c)(4) to alleviate undue burdens on operators by accommodating unpredictable permitting timelines. These changes would ensure that remedial actions are completed within practical and achievable timeframes, enhancing regulatory compliance without compromising safety. By allowing more flexibility in the timing of remedial actions, operators can better manage their resources in coordinating regulatory requirements, leading to improved economic efficiency.

49 CFR §§ 192.465(d) and 192.473(c)(4) outline the requirements that guide how an operator identifies, assesses, and remediates external corrosion threats on gas transmission pipelines. Although these rules address different sources of corrosion (routine cathodic protection deficiencies and interference currents, respectively), both require operators to act within defined timeframes, apply for necessary permits, and implement remediation plans. AGA recommends the removal of "earliest" from §§ 192.465(d) and 192.473(c)(4) and replace it with "latest", as the current language presents a recurring challenge for operators. The current regulatory language requires that remedial actions must be completed either within 15 months following the next inspection, test interval, interference survey completion, or within 6 months of obtaining necessary permits – whichever occurs first. In practice, the "earliest" aspect is counter-intuitive and imposes an undue burden on operators, as permitting timelines are often unpredictable as well as outside the operator's control, and can often extend beyond the currently required 15-month window. In addition to this change, AGA proposes extending the deadline from 6 months to 12 months in both §§ 192.465(d) and 192.473(c)(4). This change would provide operators with a more realistic and achievable timeline, particularly for projects involving long-term mitigation infrastructure.

Within Docket No. DOT-OST-2025-0026 (Regulatory Reform RFI), INGAA raised concerns that the 6-month remediation window is often insufficient to address external corrosion and complex projects that require extensive coordination, management of Land and Right-of-Way (LWOR) requirements, and securing permits due to design or excavation operations change. AGA likewise recommends replacing "within 6 months of" with "as soon as practical" to accommodate permitting delays within § 192.465(d). As written, these provisions introduce a significant risk of non-compliance due to factors beyond the operator's control, including delays in permit approvals. AGA suggests revising the language to allow more flexibility in scheduling remediation activities, particularly when permitting delays are involved.

Current language in § 192.465(f) explicitly names a specific testing method, close interval survey (CIS), that may inadvertently diminish the value of other equally valid and effective techniques. Although CIS may be appropriate in certain scenarios, it may not be the best solution or even applicable in certain situations (e.g., dense urban areas, steep terrain, highly rocky areas, or locations with loose sand). AGA offers a revision that allows operators the flexibility to choose the most suitable testing method for a given scenario, which will enable more efficient use of time and resources.

Suggested revised regulatory language is as follows:

§192.465 External corrosion control: Monitoring and remediation

…

(d) Each operator must promptly correct any deficiencies indicated by the inspection and testing required by paragraphs (a) through (c) of this section. For onshore gas transmission pipelines, each operator must develop a remedial action plan and apply for any necessary permits ~~within 6 months of~~ as soon as practicable after completing the inspection or testing that identified the deficiency. Remedial action must be completed promptly, but no later than the ~~earliest~~ latest of the following: prior to the next inspection or test interval required by this section; within 1 year, not to exceed 15 months, of the inspection or test that identified the deficiency; or as soon as practicable, not to exceed ~~6~~ 12 months, after obtaining any necessary permits.

…

(f) An operator must determine the extent of the area with inadequate cathodic protection for onshore gas transmission pipelines where any annual test station *reading* (pipe-to-soil potential measurement) indicates cathodic protection levels below the required levels in appendix D to this part.

…

(2) To address systemic causes, an operator must ~~conduct close interval surveys in both directions from the test station with a low cathodic protection reading at a maximum interval of approximately 5 feet or less~~ determine the extent of the cathodic protection deficiency by sound engineering test or analysis. An operator must conduct close interval surveys unless it is impractical based upon geographical, technical, or safety reasons. ~~An operator must complete close interval surveys required by this section with the protective current interrupted unless it is impractical to do so for technical or safety reasons.~~ An operator must remediate areas with

insufficient cathodic protection levels, or areas where protective current is found to be leaving the pipeline, in accordance with paragraph (d) of this section. An operator must confirm the restoration of adequate cathodic protection following the implementation of remedial actions undertaken to mitigate systemic causes of external corrosion.

§ 192.473 External corrosion control: Interference currents.

…

(c) For onshore *gas* transmission pipelines, the program required by paragraph (a) of this section must include:

…

(4) Application for any necessary permits within 6 months of completing the interference survey that identified the deficiency. An operator must complete remedial actions promptly, but no later than the latest ~~earliest~~ of the following: within 15 months after completing the interference survey that identified the deficiency; or as soon as practicable, but not to exceed 12 ~~6~~ months, after obtaining any necessary permits.

Revisions to Subpart H

AGA suggests providing alternate language in § 192.385 (Manual service line shut-off valve installation to remove regulatory uncertainty regarding the associated maintenance requirements for manual service line shut off valves. The adjusted language seeks to clarify necessary minimum requirements for the inspection of curb valves. Many operators install plastic ball valves that are classified as "maintenance free" by the manufacturer's specification, meaning they are not required to be physically turned on a set cadence to ensure operability. However, given the current wording of this § 192.385(c) and FAQ guidance[26], some operators and regulators interpret this section as requiring a service line shutoff valve be physically turned during an inspection, regardless of manufacturer specification. Verification of valve operability adds cost to inspections and can result in inadvertent interruption of gas supply to the customer. Typically, the plastic curb valves used in this application are quarter-turn valves, which provides for very little margin of error when checking for operability, i.e. turning the valve to a less than fully closed position so as not to interrupt service to the customer versus fully closing the valve. An attempt to

[26] PHMSA Excess Flow Valve Frequent Asked Questions (issued May 17, 2022); FAQ #14; Link: EFV FAQs | PHMSA

partially operate such a quarter turn valve may inadvertently result in the closure of curb valves. Such a practice is typically in contravention with manufacturer's specifications and can lead to the unintended consequence of customer outages (manual service line valves are typically installed on lines serving commercial or industrial customers) and additional burdensome costs to reenergize the line and relight the customers.

Suggested revised regulatory language is as follows:

§192.385 Manual service line shut-off valve installation

…

(c) Manual service line shut-off valves for any new or replaced service line must be installed in such a way as to allow accessibility during emergencies. Manual service shut-off valves installed under this section are subject to regular scheduled maintenance, ~~as documented by the operator and consistent with the valve manufacturer's specification~~ to ensure that the valve is available if an event occurs which would require shutting off gas supply, and maintained in accordance with the valve manufacturer's specification.

Revisions to Alternative Technology Notification Requirements

AGA suggests removing the requirements stated in §§ 192.319(e) and 192.461(g) to notify PHMSA in accordance with § 192.18 when using other equivalent technologies by striking both paragraphs entirely. In both cases, preceding paragraphs (§§ 192.319(d) and 192.461(f), respectively) explicitly allow for the use of "other technology that provides comparable information about the integrity of the coating." This statement in both paragraphs establishes the performance criteria that the other technology must meet.

As operators already bear the burden to prove that an alternative technology delivers results comparable to the explicitly stated coating assessment technologies prior to its use, it is unduly burdensome to require a submittal of notification to PHMSA that a technology has been found effective and subsequently wait 90 days before using the proven technology. These notification requirements introduce administrative waste for both operators and PHMSA alike, can cause assessment delays for operators, and serves to hinder the adoption of new, more effective technologies. The recession of §§ 192.319(e) and 192.461(g) will reduce the number of notifications an operator is required to provide to PHMSA and the number of notifications PHMSA staff must review, providing mutual efficiency gains.

7. Operations and Maintenance Requirements

Question 7:
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.

Uprating to a pressure that will produce a hoop stress of 30 percent or more of SMYS in steel pipelines.

Since the introduction of MAOP reconfirmation requirements of RIN 1 within § 192.624, operators have had the flexibility to determine between six approaches to reconfirm MAOP, where applicable. These six methods, including pipe replacement, pressure testing, Engineering Critical Assessment (ECA), and alternative technology, are considered equivalent and provide the same level of safety and risk reduction. Various legacy sections of 49 CFR 192 did not reconcile these changes, including § 192.555, which, as written, assumes that an operator only has transmission pipe that has been subjected to a pressure test or is untested. There is no allowance made for pipe whose MAOP has been reconfirmed using ECA or alternative technology. The suggested changes below align the code and provide operators with additional incentives to utilize advanced technology to determine risk.

§ 192.555 Uprating to a pressure that will produce a hoop stress of 30 percent or more of SMYS in steel pipelines.

…

(d) After complying with paragraph (b) of this section, an operator that does not qualify under paragraph (c) of this section may increase the previously established maximum allowable operating pressure if at least one of the following requirements is met:

(1) The segment of pipeline is successfully tested in accordance with the requirements of this part for a new line of the same material in the same location.

(2) The segment of pipeline is inspected using the method of engineering critical assessment (ECA) per § 192.632. The target increased maximum

allowable operating pressure must be lower than the lowest predicted failure pressure for any known or postulated defect, or interacting defects, remaining in the pipe divided by the greater of 1.25 or the applicable factor listed in § 192.619(a)(2)(ii).

(3) Operators may use an alternative technical evaluation process that provides a documented engineering analysis for establishing MAOP. If an operator elects to use alternative technology, the operator must notify PHMSA in advance in accordance with § 192.18.

(~~2~~4) An increased maximum allowable operating pressure may be established for a segment of pipeline in a Class 1 location if the line has not previously been tested, and if:

…

Verification of Pipeline Material Properties and Attributes: Onshore steel transmission pipelines.

AGA recommends that § 192.607 be amended to allow for the voluntary application of material testing methods in this section to lines other than onshore transmission lines, while maintaining the existing mandatory requirements to verify onshore steel transmission line material attributes in accordance with this section. There is no technical reason why the methods described in this section could not be voluntarily applied to other steel pipelines lines. Currently, only transmission sections mandate the use of § 192.607, but non-transmission sections could be changed to use § 192.607 in the future. Additionally, the Operator of a distribution pipeline should have the option to voluntarily use the methods in § 192.607 for any pipe of unknown properties or specification (e.g. tensile properties, wall thickness) rather than being limited to the current provisions in §§ 192.107 and 192.109 when determining design pressure.

AGA proposes to modify the requirement to perform verification of material properties and attributes (§ 192.607(c)) is such that the original intent, (i.e., to require opportunistic material verification solely for steel transmission pipelines) is retained.

§ 192.607 Verification of Pipeline Material Properties and Attributes: Onshore steel ~~transmission~~ pipelines.

(a) Applicability. Wherever required by this part, operators of onshore steel ~~transmission~~ pipelines must document and verify material properties and attributes in accordance with this section.

…

(c) ***Verification of material properties and attributes*** *for onshore steel transmission pipelines*. If an operator does not have traceable, verifiable, and complete records, for onshore steel transmission pipelines, required by paragraph (b) of this section, the operator must develop and implement procedures for conducting nondestructive or destructive tests, examinations, and assessments in order to verify the material properties of aboveground line pipe and components, and of buried line pipe and components when excavations occur at the following opportunities: Anomaly direct examinations, in situ evaluations, repairs, remediations, maintenance, and excavations that are associated with replacements or relocations of pipeline segments that are removed from service. Tests, examinations, and assessments must be appropriate for verifying the necessary material properties and attributes. ~~The procedures must also provide for the following:~~

~~(1) For nondestructive tests, at each test location, material properties for minimum yield strength and ultimate tensile strength must be determined at a minimum of 5 places in at least 2 circumferential quadrants of the pipe for a minimum total of 10 test readings at each pipe cylinder location.~~

~~(2) For destructive tests, at each test location, a set of material properties tests for minimum yield strength and ultimate tensile strength must be conducted on each test pipe cylinder removed from each location, in accordance with API Specification 5L.~~

~~(3) Tests, examinations, and assessments must be appropriate for verifying the necessary material properties and attributes.~~

~~(4) If toughness properties are not documented, the procedures must include accepted industry methods for verifying pipe material toughness.~~

~~(5) Verification of material properties and attributes for non-line pipe components must comply with paragraph (f) of this section.~~

Move § 192.607(c)(1) to § 192.607(d)

(d) ~~***Special***~~ ***Requirements for nondestructive Methods***. Procedures developed in accordance with paragraph (c) of this section for verification of material properties and attributes using nondestructive methods must:

(1) Minimum yield strength and ultimate tensile strength must be determined at a minimum of 5 places in at least 2 circumferential quadrants of the pipe for a minimum total of 10 test readings at each pipe cylinder location.

(~~1~~2) Use methods, tools, procedures, and techniques that have been validated by a subject matter expert based on comparison with destructive test results on material of comparable grade and vintage;

(~~2~~3) Conservatively account for measurement inaccuracy and uncertainty using reliable engineering tests and analyses; and

(~~3~~4) Use test equipment that has been properly calibrated for comparable test materials prior to usage.

Add a section for destructive testing requirements, move from § 192.607(c)(2)

(h) *Requirements for destructive testing*. For minimum yield strength and ultimate tensile strength, procedures developed in accordance with paragraph (c) of this section must be conducted in accordance with API Specification 5L.

Proposed changes to § 192.607 (f)

(f) *Onshore steel transmission pipeline* ***components.*** For mainline onshore steel transmission pipeline components other than line pipe, an operator must develop and implement procedures in accordance with paragraph (c) of this section for establishing and documenting the ANSI rating or pressure rating (in accordance with ASME/ANSI B16.5 (incorporated by reference, see § 192.7)),

…

Revisions to Subpart K

AGA suggests removal of § 192.607(g). The purpose of verifying pipeline material properties and attributes is to mitigate gaps in system records. Therefore, system records should be updated once the verification process is complete. Stating material property verification testing cannot be used to raise the grade or specifications is antithetical to the intent of this section. Moreover, § 192.607 is not the section applicable to MAOP uprating requirements. Newly verified material properties do not circumvent the MAOP uprating process. The current language in § 192.607 does not enhance pipeline safety and could contribute to regulatory uncertainty.

§192.607 Verification of Pipeline Material Properties and Attributes: Onshore steel transmission pipelines.

…

~~(g) *Uprating*. The material properties determined from the destructive or nondestructive tests required by this section cannot be used to raise the grade or specification of the material, unless the original grade or specification is unknown and *MAOP* is based on an assumed yield strength of 24,000 psi in accordance with §192.107(b)(2).~~

Revisions to Subpart L

Change in Class Location: Confirmation or Revision of Maximum Allowable Operating Pressure

Notwithstanding potential changes to class location designation and associated requirements (see response to topic 2 of the Pipeline Safety Regulations section of this ANPRM), PHMSA should extend the timeline for confirming or revising a pipeline's MAOP as prescribed by 49 CFR § 192.611(d) from 24 months to 48 months.

The 24-month timeframe for confirming or revising MAOP as a result of class location change was established in the original implementation of the CFR. Since the 1970s, many new regulations have been established by city, county, state, and federal agencies. Accordingly, the average length of time to obtain a construction permit has increased considerably. As a result, permitting for construction activities requires significantly more time, often consuming the vast majority of the 24-month remediation window. Operators are then left with a very narrow timeframe in which to execute their work. Further complications arise when consideration is given to high natural gas demand periods (requiring reliable capacity) or conflicting pipeline outages as the result of other regulatory requirements. If the affected segments cannot be tested or replaced, operators may be required to significantly reduce operating pressure until work can be completed. Since pipelines are often interconnected, a pressure reduction in one line may indirectly require pressure reductions in adjacent lines, which can have a significant impact on the capacity of the transmission system. These restrictions may also prohibit the ability to perform work on other pipelines, as the overall system may not be able to support further reductions in capacity. Considering that the condition and attributes of the pipeline have not changed as a result of the class location change, an extension to the 24-month class location change confirmation timeframe is appropriate in order to afford operators greater ability to plan pipeline outages that minimize negative impacts to system capacity and reliability.

Extending the class location change confirmation timeframe would also provide operators better opportunity to coordinate class location change work with other required work to help minimize the number of outages and reduce costs for ratepayers. Per 49 CFR § 192.624(b)(2), PHMSA grants operators up to four years to reconfirm pipeline segments that are newly added to their MAOP reconfirmation scope if the segments are identified less than four years from the deadline prescribed in 49 CFR § 192.624(b)(2). Updating the timeframe for class location change confirmation would harmonize the two PSR sections, which address similar risks (i.e., a pipeline segment that may not have been tested sufficiently for its established MAOP).

Moreover (as per the discussion regarding the proposed changes to § 192.555), § 192.611 does not account for changes to 49 CFR 192 made in RIN 1. Reconfirmation methods one through six in § 192.624 draw an equivalency in safety and risk reduction in performing engineering critical assessment (ECA), pressure testing, and alternative technology. PHMSA should provide flexibility to ensure that confirmation or revision of MAOP following a class location change can be harmonized with MAOP established using ECA or alternative technology. For instance, ECA does not involve a test pressure, but rather determines the predicted failure pressure of the largest flaw detected during the NDT or in line inspection. Therefore, current class location change requirements do not adequately account for this method.

PHMSA should therefore amend class location change requirements in § 192.611 to align with codified MAOP reconfirmation requirements in order to allow operators to couple advanced inspection technologies (i.e., in line inspection and nondestructive testing tools) with computer modeling methods.

PHMSA should amend § 192.611 as follows:

§192.611 Change in class location: Confirmation or revision of maximum allowable operating pressure.

(a) If the hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with the present class location, and the segment is in satisfactory physical condition, the maximum allowable operating pressure of that segment of pipeline must be confirmed or revised according to one of the following requirements:

…

(2) If the segment involved was previously subject to maximum allowable operating pressure reconfirmation using either the method of engineering critical assessment or alternative technology:

(i) The maximum allowable operating pressure is 0.8 times the product of the previously reconfirmed MAOP and class location factor in Class 2 locations, 0.667 times the product of the previously reconfirmed MAOP and class location factor in Class 3 locations, or 0.555 times the product of the previously reconfirmed MAOP and class location factor in Class 4 locations. The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

(ii) The alternative maximum allowable operating pressure is 0.8 times the product of the previously reconfirmed MAOP and class location factor in Class 2 locations and 0.667 times the product of the previously reconfirmed MAOP and class location factor in Class 3 locations. For pipelines operating at alternative maximum allowable pressure per § 192.620, the corresponding hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations.

(~~2~~3) The maximum allowable operating pressure of the segment involved must be reduced so that the corresponding hoop stress is not more than that allowed by this part for new segments of pipelines in the existing class location.

(~~3~~4) The segment involved must be tested in accordance with the applicable requirements of subpart J of this part, and its maximum allowable operating pressure must then be established according to the following criteria:

...

(d) Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under §192.609 must be completed within ~~24~~ 48 months of the change in class location. Pressure reduction under paragraph (a)(1) or (2) of this section within the ~~24-~~48-month period does not preclude establishing a maximum allowable operating pressure under paragraph (a)(3) of this section at a later date.

…

__Change in Class Location: Change in Valve Spacing__

As currently written, § 192.610 is unnecessarily complex and adds significant administrative burden without commensurate safety benefits. The section specifies that if a class location change on a transmission pipeline occurs after October 5, 2022, and results in a pipe replacement of 2 or more miles (in the aggregate) within any 5 contiguous miles over a 24-month period, the operator must install rupture-mitigation valves (RMV) or alternative equivalent technologies. The dynamic nature of transmission pipeline projects – where scope, timing, and location can unexpectedly shift, in some cases, multiple times – makes this requirement difficult to implement consistently and reliably. Tracking multiple pipeline replacements to determine whether 2 miles in aggregate is achieved in a 24-month period is also administratively burdensome.

In contrast, section 957 of the California Public Utilities Code[27] offers a practical, predictable, and simplified framework for the installation of automatic shutoff or remote-controlled valves. The criteria it offers is straightforward and enables effective planning and execution of valve replacement projects without the added complexity of retrospective spatial and temporal analysis while preserving the safety intent of the regulation.

In lieu of tracking various aggregated replacement lengths, AGA recommends that the regulation focus solely on pipeline replacement segments of two miles or more as the threshold for RMV installation. This adjustment would preserve the safety intent of the regulation while significantly reducing the administrative and operational burden on operators.

AGA suggests the following changes to the regulatory text:

§192.610 Change in class location: Change in valve spacing.

(a) If a class location change on a transmission pipeline occurs after October 5, 2022, and results in pipe replacement ~~of 2 or more miles, in the aggregate, within any 5 contiguous miles within a 24- month period~~ of 2 or more contiguous miles to meet the maximum allowable operating pressure (MAOP) requirements in §192.611, §192.619, or §192.620, then the requirements in §§192.179, 192.634, and 192.636, as applicable, apply to the new class location, and the operator must install valves, including rupture-mitigation valves (RMV) or alternative equivalent technologies, as necessary, to comply with those sections. Such valves must be installed within

[27] C**alifornia Code Public Utilities Code – PUC DIVISION 1 - REGULATION OF PUBLIC UTILITIES PART 1 - PUBLIC UTILITIES ACT CHAPTER 4.5 - Gas Pipeline Safety ARTICLE 2 - Natural Gas Pipeline Safety Act of 011**
§ 957 California Code, PUC 957.

24 months of the class location change in accordance with the timing requirement in §192.611(d) for compliance after a class location change.

(b) If a class location change occurs after October 5, 2022, and results in pipe replacement of less than ~~2 miles within 5 contiguous miles during a 24 month period~~ 2 contiguous miles to meet the MAOP requirements in §192.611, §192.619, or §192.620, then within 24 months of the class location change, in accordance with §192.611(d), the operator must either:

…

Emergency Plans

AGA recommends revising 49 CFR 192.615(b)(3). The current code language requires that each operator shall: "Review employee activities to determine whether the procedures were effectively followed in each emergency." The requirement to review "each" emergency is overly burdensome. A formal definition of "emergency" does not exist in the Federal Gas Code (49 CFR 191 or 192). Operators who define it broadly may be required to perform thousands of such reviews each year, even when effectiveness of emergency response procedures (including adherence) is only evident in the aggregate. Operators should be given additional latitude in how they administer the review of emergency response procedure effectiveness and adherence. One medium-sized natural gas distribution operator estimates that amending this requirement could realize savings of $75,000 per year in the operator's labor costs.

§ 192.615 Emergency plans.

…

(b) Each operator shall:

…

(3) Review employee activities to determine whether emergency procedures established under paragraph (a) are effectively followed ~~the procedures were effectively followed in each emergency~~.

…

MAOP Reconfirmation

AGA also recommends revising 49 CFR § 192.624(b) to extend the MAOP Reconfirmation deadlines by seven years. This extension would allow operators the flexibility to prioritize safety and compliance projects while maintaining pipeline reliability, and aligns with a recommendation previously made by INGAA in response to the DOT's *Ensuring Lawful Regulation; Reducing Regulation and Controlling Regulatory Costs* RFI in May 2025. AGA would like to reinforce INGAA's observation that the pipeline segments subject to MAOP Reconfirmation are also subject to increased safety measures applied under 49 CFR Part 192, Subpart O and 49 CFR § 192.710, which impose integrity management principles.[28] Bearing in mind that Section 23 of the PIPES Act of 2011 does not mandate a timeframe by when pipeline testing must be completed[29], this extension would grant operators more time to consider cost-effective but complex options such as Engineering Critical Assessment (49 CFR § 192.624(c)(3)) and Alternative Technology (49 CFR § 192.624(c)(6)), and spread the costs of completing MAOP reconfirmation activities across a broader timeframe, reducing the impacts to operators and their customers. While PHMSA allows operators to reduce pressure to reconfirm MAOP[30], the interconnectivity of pipelines on an operator's systems can limit the application of this method. Reducing pressure in a single line may require lowering pressure across the entire system or isolating the segment, both of which can significantly reduce capacity and reliability. In many cases, this leaves operators with limited options, often needing to pursue higher-cost methods such as retesting or replacement.

As INGAA stated in their DOT RFI comments, operators are still heavily dependent on pressure testing and replacement as reconfirmation methods due to the inaccessibility of the Engineering Critical Assessment provisions of 49 CFR § 192.632 as a result of ambiguity and conservative engineering assumptions.[31] These methods can take multiple years to complete, and are costly. Additionally, pressure testing requires operators to take a pipeline out of service, directly impacting customers. PHMSA's Regulatory Impact Analysis (RIA)[32] for RIN 1 considerably underestimated the costs associated with MAOP reconfirmation at $27.9 million annually (with a 7% discount rate), which includes the material verification activities associated with 49 CFR § 192.607. Five years into

[28] *See* INGAA comments for Docket No. DOT-OST-2025-0026, filed May 5, 2025 (https://www.regulations.gov/comment/DOT-OST-2025-0026-0872), at 25.

[29] Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (https://www.govinfo.gov/content/pkg/PLAW-112publ90/pdf/PLAW-112publ90.pdf)

[30] 49 CFR §§ 192.624(c)(2), 192.624(c)(5)

[31] Comments on *Ensuring Lawful Regulation; Reducing Regulation and Controlling Regulatory Costs*, Docket No. DOT-OST-2025-0026 (Regulatory Reform RFI), p. 29, available at https://www.regulations.gov/comment/DOT-OST-2025-0026-0872.

[32] Pipeline and Hazardous Materials Safety Administration. (2019, October 1). *Pipeline safety: Safety of gas transmission pipelines; MAOP reconfirmation, expansion of assessment requirements, and other related amendments* (Final Rule). Federal Register, 84(190), 52180–52257. https://www.federalregister.gov/documents/2019/10/01/2019-20306/pipeline-safety-safety-of-gas-transmission-pipelines-maop-reconfirmation-expansion-of-assessment

complying with the MAOP reconfirmation requirements, one operator has forecasted actual costs to be approximately three times PHMSA's initial estimates, based on retesting or replacing pipeline segments in scope. Allowing operators to extend this work beyond PHMSA's initial deadlines is expected to have little impact to safety in light of the current integrity management-related requirements that already exist on these pipelines. Such an extension will help better align actual costs incurred to PHMSA's RIA estimates, and will reduce unnecessary cost burdens to operators.

> **§ 192.624 Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines**
>
> **…**
>
> **(b)** ***Procedures and completion dates.*** Operators of a pipeline subject to this section must develop and document procedures for completing all actions required by this section by July 1, 2021. These procedures must include a process for reconfirming MAOP for any pipelines that meet a condition of § 192.624(a), and for performing a spike test or material verification in accordance with §§ 192.506 and 192.607, if applicable. All actions required by this section must be completed according to the following schedule:
>
> (1) Operators must complete all actions required by this section on at least 50% of the pipeline mileage by July 3, ~~2028~~ 2035.
>
> (2) Operators must complete all actions required by this section on 100% of the pipeline mileage by July 2, ~~2035~~ 2042 or as soon as practicable, but not to exceed 4 years after the pipeline segment first meets a condition of § 192.624(a) (e.g., due to a location becoming a high consequence area), whichever is later.

In addition to extending the MAOP reconfirmation deadlines, PHMSA should expeditiously clarify test record requirements for tests performed prior to the adoption of the pipeline safety regulations in 1970. PHMSA recently issued a technical correction affirming that 49 CFR § 192.624 does not require retroactively applying 49 CFR § 192.517 to pressure test records and stated "PHMSA intends to provide additional guidance in addressing the records needed to satisfy the traceable, verifiable, and complete standard for historical, pre-PSR pressure testing in the near future." Until PHMSA issues this guidance, operators may apply differing requirements to establish MAOP reconfirmation scope, leading to inconsistently applied safety actions and the possibility of unnecessarily incurred costs impacting operators and customers.

Engineering Critical Assessment for MAOP Reconfirmation – In-line Inspection Technologies

AGA recommends revising the 49 CFR § 192.632(c) requirements associated with assessing types of circumferential cracking. Natural gas pipeline ILI tools capable of directly identifying circumferential cracks and meeting API RP 1163 requirements do not currently exist. When merited, ILI technologies such as inertial measurement units with the ability to identify bend strain can be used to indicate pipeline regions more susceptible to circumferential cracking. In addition, requirements on when girth weld defects need to be evaluated are already stated in § 192.632(c)(2). The statement about girth weld cracks in the preceding paragraph § 192.632(c) creates confusion by providing contradictory requirements. Current regulatory language in 192.632(c) discussing various types of circumferential cracking can force operators to use pipe replacement or pressure testing rather than Engineering Critical Assessments, thereby unnecessarily increasing costs while not improving the level of safety achieved.

Engineering Critical Assessment for MAOP Reconfirmation — Interpretation and Evaluation of Assessment Results

AGA further recommends revising 49 CFR § 192.632(c)(5) requirements associated with interpretation and evaluation of assessment results. Multiple layers of conservatism are already built into the process of evaluating the predicted failure pressure of anomalies other than accounting for ILI uncertainties such as tool tolerance. The excessive layering of conservativeness is overly burdensome and unnecessary to ensure pipeline safety. Examples include the following:

- Fitness for service assessment models such as ASME/ANSI B31G, R-STRENG, and API 579.
- Design factor for the class location.
- Pipe grade's specified minimum yield strength (SMYS) used in calculations documented for TVC records. Invariably, the recorded SMYS is lower than the actual yield strength. If the grade is not documented in TVC records and an ECA is being completed, an even more conservative 30,000 psi value is used for the yield strength in calculations per § 192.632(a)(2)(iv).
- If material toughness is not documented in TVC records, conservative values in 192.712(e)(2)(i) are used for material toughness. If lab testing is completed or representative pipe samples, the Charpy v-notch toughness values must be based upon the lowest operational temperatures per § 192.632(a)(1).

Engineering Critical Assessment for MAOP Reconfirmation – Data Assumptions

AGA also recommends revising 49 CFR § 192.632(a)(2)(iv) to include options beyond the 30,000 psi assumption when performing an ECA, when SMYS is not known or is not documented through traceable, verifiable, and complete records. PHMSA should allow "appropriate values based on other known pipe attributes and system data" in place of "30,000 psi" because the use of a default 30,000 psi SMYS value is overly conservative, particularly when other known pipe attributes and system specific data indicate a higher grade is more appropriate. Applying 30,000 psi in corrosion or crack analysis models (e.g., R-STRENG, KAPA, API 579, MAT-8) can result in predicted failure pressures below MAOP for anomalies that would otherwise remain in service, leading to unnecessary remediation. For example, an operator conducted a corrosion analysis model on a pipeline using available data vs. the prescribed 30,000 psi assumption and, with all other factors identical, the analysis using the 30,000 psi assumption indicated that there should have been a pipeline failure on an otherwise acceptable pipeline.

Overall, the ECA process discourages operators by being weighed down with overly conservative assumptions. INGAA stated in their comments to the DOT's "*Ensuring Lawful Regulation; Reducing Regulation and Controlling Regulatory Costs*" RFI[33] that" using the lowest bound values layers additional conservatism onto an already-conservative analysis for predicted failure pressures of cracks, using lower shelf CVN values." AGA agrees with this statement. While PHMSA has allowed operators to use engineering critical assessment (ECA) to reconfirm MAOP, the low number of miles reconfirmed through ECA across the industry should be viewed as an indication that the ECA process is so cumbersome as to drive operators to opt for other methods, including pressure testing which can be costly and impact an operator's system capacity.

If PHMSA were to modify the ECA process and adopt the recommended amendments described here, one operator has estimated that they could achieve cost avoidance in the range of $250-350 million to achieve 100% reconfirmation per § 192.624, by leveraging ECA (instead of pressure testing) for approximately 65-70% of the affected pipeline segments. This cost savings was determined by taking the operators' current forecast to complete MAOP reconfirmation and reducing it by an approximate total for ECA reconfirmation, which was calculated using the number of miles that could be reconfirmed through an ECA process that considers data sources beyond TVC records, conservative

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[33] Comments on *Ensuring Lawful Regulation; Reducing Regulation and Controlling Regulatory Costs*, Docket No. DOT-OST-2025-0026 (Regulatory Reform RFI), p. 29, available at https://www.regulations.gov/comment/DOT-OST-2025-0026-0872.

assumptions (e.g., industry CVN data), and cost assumptions based on sample projects and actual contractor costs.

AGA therefore recommends the following changes to the associated regulatory text:

§ 192.632 Engineering Critical Assessment for Maximum Allowable Operating Pressure Reconfirmation: Onshore steel transmission pipelines.

...

(a)(2)(iv) If SMYS or actual material yield and ultimate tensile strength is not known or not documented by traceable, verifiable, and complete records, then the operator must use appropriate values based on other known pipe attributes and system data, assume 30,000 p.s.i.**,** or determine the material properties using §192.607.

...

(c) *In-line inspection***.** An inline inspection (ILI) program to determine the defects remaining the pipe for the ECA analysis must be performed using tools that can detect wall loss, deformation from dents, wrinkle bends, ovalities, expansion, seam defects, including cracking and selective seam weld corrosion, longitudinal~~, circumferential and girth weld~~ cracks, hard spot cracking, and axial stress corrosion cracking.

...

(2) If the pipeline has had a reportable incident, as defined in §191.3, attributed to a girth weld or other circumferential crack failure since its most recent pressure test, then the ILI program must include a tool that can detect ~~girth weld defects~~ the type of defect to which the incident was attributed unless the ECA analysis performed in accordance with this section includes an engineering evaluation program to analyze and account for the susceptibility of ~~girth weld~~ failure of that type of defect due to lateral stresses.

(5) Interpretation and evaluation of assessment results must meet the requirements of §§192.710, 192.713, and subpart O of this part~~, and must conservatively account for the accuracy and reliability of ILI, in-the-ditch examination methods and tools, and any other assessment and~~

~~examination results used to determine the actual sizes of cracks, metal loss, deformation and other defect dimensions by applying the most conservative limit of the tool tolerance specification. ILI and in-the-ditch examination tools and procedures for crack assessments (length and depth) must have performance and evaluation standards confirmed for accuracy through confirmation tests for the defect types and pipe material vintage being evaluated. Inaccuracies must be accounted for in the procedures for evaluations and fracture mechanics models for predicted failure pressure determinations~~.

Revisions to Subpart M (and associated Subpart O requirements)

Analysis of predicted failure pressure and critical strain level.

49 CFR § 192.632 also requires operators to determine the predicted failure pressure of defects in accordance with 49 CFR § 192.712. Here, the requirement to assume 120 ft-lbs Charpy v-notch (CVN) toughness for cracks and crack-like defects analysis in the absence of TVC material data introduces overly conservative assumptions into flaw analysis following a pressure test, which can render ECA unachievable for many operators. Additionally, 49 CFR § 192.712 (e)(2)(i)(C)[34] specifies that if toughness data for the pipe material is not TVC, operators must use a conservative default value when performing analyses under this section of the code. These conservative assumptions lead to larger initial flaw sizes, which in turn reduce the predicted fatigue life and may incorrectly suggest that the pipeline is unfit for service. The inconsistency becomes more pronounced when lower, code-defined or measured CVN values are used for final flaw sizing. IPC2018-78554[35] highlights that this approach can result in unrealistic fatigue life predictions, including zero remaining fatigue life, for flaws that would otherwise be considered acceptable.

While PHMSA's intent may be to encourage toughness testing, a more practical and technical alternative is to use industry toughness data as operators opportunistically expand their toughness databases as prescribed in 49 CFR § 192.607. AGA is requesting the scope of 49 CFR § 192.712(e)(2)(i) be expanded to allow the use of statistically derived, industry-

[34] 49 CFR § 192.712(e)(2)(i)(C): *If the pipeline segment does not have a history of reportable incidents caused by cracking or crack-like defects, maximum Charpy v-notch toughness values of 13.0 ft.-lbs. for body cracks and 4.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion defects...*

[35] Ellinger, M, Lutz, A, Bubenik, T, & McMahan, T. "A Sensitivity Study: Effects of Toughness Values on Fatigue Crack Growth Analysis of Just-Survived Flaws Following a Pressure Test." *Proceedings of the 2018 12th International Pipeline Conference*. *Volume 1: Pipeline and Facilities Integrity*. Calgary, Alberta, Canada. September 24–28, 2018. V001T03A015. ASME. https://doi.org/10.1115/IPC2018-78554

wide data in lieu of the conservative default CVN toughness values specified in the regulations of 4.0 ft.-lbs or internally generated values. The ExxonMobil study[36] compiled Charpy and toughness data across ERW seams and identified the lowest weld centerline toughness as approximately 25 ksi-in^0.5, which correlates to about 4.5 ft-lb using the Wallin correlation. This finding effectively invalidates section 49 CFR § 192.712(e)(2)(i)(D) as a conservative assumption. In the absence of specific toughness data, AGA recommends referencing industry toughness data to support engineering assessments, as mentioned previously.

Gathering additional CVN data is challenging, as it requires standardized impact testing and/or destructive testing during field excavations, which can be costly and resource intensive. One operator estimates that, on an ECA project where CVN toughness values are not TVC, approximately 80% of costs associated with destructive testing could be avoided while operators work to reconfirm pipelines within the established 49 CFR § 192.624(b) timeframes. Allowing for the use of statistical analysis of industry wide pipe material properties from the common manufacturers and known vintage material-properties used, along with appropriate data confidence intervals, would enable operators to more realistically evaluate their pipelines and make more effectively informed decisions. Ongoing efforts such as PRCI JCAS-01, which includes over 2,700 toughness tests across multiple operators, provide statistically supported values categorized by manufacturer, seam type, and vintage. The PRCI report[37] offers a credible basis for replacing the default 120 ft-lbs with more representative values. Industry collaboration with PHMSA will help align regulatory expectations with data-driven, risk-informed practices.

While many operators and technical consultants are collaborating to build a unified database – such as Engineering Mechanics Corporation of Columbus (Emc^2) and PRCI – current code provisions limit the benefits of leveraging cross-utility data sharing. Currently, the database of representative CVN values may not be used without prior notification to PHMSA for review and approval (49 CFR § 192.712(e)(2)(i)(E)), which adds delay and unnecessary regulatory burden to the MAOP reconfirmation process and may unintentionally discourage technological innovation in developing industry-wide data consistency for effective alternative solutions in managing pipeline safety. PHMSA should consider removing the requirement of prior notification to PHMSA to alleviate the process of performing an ECA and instead requests that PHMSA either specify acceptable methodologies or allow operators flexibility. Operators must estimate how long they can

[36] Bagnoli, K., Neeraj, T., Pioszak, G., Holloman, R., Thorwald, G., & Hay, C. "Fracture Toughness Evaluation of Pre-1980's Electric Resistance Welded Pipeline Seam Welds." Proceedings of the 2022 14th International Pipeline Conference, Volume 3: Operations, Monitoring, and Maintenance; Materials and Joining. Calgary, Alberta, Canada. September 26–30, 2022. Paper No: IPC2022-86014. ASME. https://doi.org/10.1115/IPC2022-86014
[37] Wilkowski, G., Kurth-Twombly, E., Sallaberry, C., Bagnoli, K., & Kurth, R. (2024). Pragmatic application of MegaRule RIN 1 - 192.712 toughness values L2 and L3 procedures (PRCI Report No. PR-276-223814-R02). Pipeline Research Council International. https://doi.org/10.55274/R0000081

safely operate a pipeline by using a recognized method for predicting crack growth over time. This change would streamline the process for evaluating the CVN values without unnecessary regulatory delays that could impact an operator's ability to comply with the timeframes established by PHMSA to repair safety-related conditions.

AGA offers the following recommended revisions to the associated regulatory text:

§ 192.712 Analysis of predicted failure pressure and critical strain level:

...

(e)(2)(i)(C) If the pipeline segment does not have a history of reportable incidents caused by cracking or crack-like defects, maximum Charpy v-notch toughness values ~~of 13.0 ft.-lbs. for body cracks and 4.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion defects~~ established using statistical modeling of industry data may be assumed;

...

(e)(2(i)(E) Other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of crack-related conditions of the pipeline segment. ~~Operators using an assumed Charpy v-notch toughness value must notify PHMSA in advance in accordance with 49 CFR § 192.18 and include in the notification the bases for demonstrating that the Charpy v-notch toughness values proposed are appropriate and conservative for use in analysis of crack-related conditions~~.

Transmission lines: Repair criteria for onshore transmission pipelines – Electric Resistance Welded (ERW) Seams

Electric resistance welded (ERW) pipes have long been a focus of integrity management programs due to historical seam failures, especially in older low-frequency ERW (LF-ERW) pipes. Advancements in manufacturing have led to the development of high-frequency ERW (HF-ERW) pipe, which offers improved weld quality and reliability compared to its low-frequency predecessor. PHMSA removed these two sections on "high frequency" ERW seams from immediate repair condition classification as a result of the DC Circuit Court's decision to vacate §§ 192.714(d)(1)(iv) and 192.933(d)(1)(iv) in August 2024. However, references to "high frequency" ERW were left intact across the 1-year, 2-

year, and Monitored conditions classifications within 49 CFR §§ 192.714(d)(2)(vi), 192.714(d)(3)(v), 192.933(d)(2)(vii), and 192.933(d)(3)(v). PHMSA's inclusion of HF-ERW pipe alongside LF-ERW have significantly increased operator workload. Treating HF-ERW and LF-ERW equally under the same remediation criteria has led to additional excavations and repairs that may not be warranted based on actual risk. For some operators, this can cost approximately $700,000 per excavation, increasing costs for customers without a corresponding safety benefit.

To address this inconsistency, AGA recommends that PHMSA revise 49 CFR §§ 192.714(d)(2)(vi), 192.714(d)(3)(v), 192.933(d)(2)(vi), and 192.933(d)(3)(v) to remove "or high-frequency" from the list of conditions requiring remediation. This would align with current industry knowledge, reduce unnecessary operational burden, and allow operators to focus on segments with a demonstrated history of integrity concerns, such as LF-ERW.

Transmission lines: Repair criteria for onshore transmission pipelines – Manufacturing and Construction Defects

Clarification should also be added to both 49 CFR §§ 192.714 and 192.933 indicating that an operator may consider manufacturing and construction related defects to be stable defects that do not require repair if the segment has been subjected to pressure testing to at least 1.25 times MAOP, and the segment has not experienced a reportable incident attributed to the same type of manufacturing or construction defect since the date of the most recent pressure test.

Temporary Pressure Reductions

The AGA also recommends changes to temporary pressure reduction criteria. Taking a pressure reduction from the peak pressure an anomaly has been subject to provides an adequate safety margin, given that the peak pressure could have been significantly higher than the pressure the pipeline happened to be operating at when the anomaly was discovered. For example, an operator could run several ILI tools during an integrity assessment, with the last ILI report not being received until some months after the tool runs are completed. The pipeline may operate at different pressures during the various tool runs (e.g., to ensure optimum system configuration and achieve the needed tool speeds for each technology), and those pressures may be lower than the pressures the pipeline operated at just before the first tool run. The pipeline may also operate at a different pressure between the time the ILI tools are run, and when the ILI results are received. Moreover, the operator may reduce pressure as a standard practice before excavating the first anomaly to verify ILI tool performance. Furthermore, state regulatory agencies and operators can have differing interpretations on the time of discovery within this this process. Therefore, mandating that the pressure reduction must be taken based on time of discoveryis arbitrary, and can cause significant and unnecessary operational challenges, as well as. unnecessary risk to system deliverability.

Consequently, AGA recommends the following revisions to §§ 192.714 and 192.933:

§ 192.714 Transmission lines: Repair criteria for onshore transmission pipelines

(b) **General.** Each operator must, in repairing its pipeline systems, ensure that the repairs are made in a safe manner and are made to prevent damage to persons, property, and the environment. A pipeline segment's operating pressure must be less than the predicted failure pressure determined in accordance with § 192.712 during repair operations. Repairs performed in accordance with this section must use pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis, including predicted failure pressure for determining MAOP, is not available, an operator must obtain the undocumented data through § 192.607. Until documented material properties are available, the operator must use the conservative assumptions in either § 192.712(e)(2) or, if appropriate following a pressure test, in § 192.712(d)(3). An operator may consider manufacturing and construction related defects to be stable defects that do not require repair if the segment has been subjected to pressure testing to at least 1.25 times MAOP, and the segment has not experienced a reportable incident attributed to the same type of manufacturing or construction defect since the date of the most recent pressure test.

...

(d)(2)(vi) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency~~ or high-frequency~~ electric resistance welding, electric flash welding, or that has a longitudinal joint factor less than 1.0, and where the predicted failure pressure determined in accordance with § 192.712(d) is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

...

(d)(3)(v) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency ~~or high-frequency~~ electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with 49 CFR § 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

…

(e)(1)(i) A level not exceeding 80 percent of the operating pressure ~~at the time the condition was discovered~~ to which the anomaly has been exposed;

§ 192.933 What actions must be taken to address integrity issues?

(a) **General requirements.** An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment. Repairs performed in accordance with this section must use pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis is not available, an operator must obtain the undocumented data through § 192.607. Until documented material properties are available, the operator must use the conservative assumptions in either § 192.712(e)(2) or, if appropriate following a pressure test, in § 192.712(d)(3). An operator may consider manufacturing and construction related defects to be stable defects that do not require repair if the segment has been subjected to pressure testing to at least 1.25 times MAOP, and the segment has not experienced a reportable incident attributed to the same type of manufacturing or construction defect since the date of the most recent pressure test.

…

(a)(1)(i)(A) A level not exceeding 80 percent of the operating pressure ~~at the time the condition was discovered~~ to which the anomaly has been exposed;

...

(d)(2)(vi) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency~~ or high-frequency~~ electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with § 192.712(d), is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

...

(d)(3)(v) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency~~ or high-frequency~~ electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with § 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

Transmission lines: Permanent field repair of welds.

AGA also recommends revisions to 49 CFR § 192.715. Currently, Subpart M prescribes minimum requirements for the maintenance of pipeline facilities; meaning, it is the applicable portion of the code which regulates the maintenance of in-service pipelines. This subpart provides extensive details on how anomalies, once discovered, should be analyzed and repaired, as needed. However, discrepancies within this subpart exist, between the treatment of weld anomalies discovered on in-service transmission lines, compared to other types of anomalies discovered on in-service transmission lines. This discrepancy has resulted in higher than necessary maintenance costs associated with the required repairs of in-service transmission welds. Major concerns can be categorized as follows: (1) Analysis of in-service weld anomalies, and (2) Repair of weld anomalies.

Analysis of weld anomalies on in-service transmission line welds:

First, § 192.712 (Analysis of predicted failure pressure and critical strain level) has an application for the analysis of anomalies or defects identified on in-service transmission pipelines. This analysis is robust, allowing for strong engineering analysis via predictive failure calculations and engineering critical assessments to determine if an anomaly found on a transmission pipeline does or does not require a repair or other further action.

However, the current language in § 192.715 does not allow the analyses described in § 192.712 to be applied toward weld anomalies identified on in-service transmission pipelines. Instead, § 192.715 simply states "each weld that is unacceptable under § 192.241(c) must be repaired". § 192.241(c) is the standard for inspection of a newly constructed (pre-in service) transmission weld. Therefore, § 192.715 requires the application of a new construction standard (of Subpart E) to be utilized as a maintenance standard for in-service welds. When considering in-service transmission welds, this imposes current construction standards to transmission pipelines that are already in-service, in some instances for a very long time. When considering the narrow language of § 192.715's application to in-service transmission pipeline welds, overly burdensome and costly repair outcomes are a result.

Importantly, the § 192.712 analysis for predictive failure pressure includes system condition considerations, whereby operators may demonstrate (through the required analysis) that certain anomalies provide no safety concerns if they operate at or below an identified predicted failure pressure. This analysis of predicted failure pressure is critical to the next step in the process, which is to determine if an anomaly must be repaired in accordance with the subpart. Therefore, Subpart M does not require all in-service anomalies to be repaired, but only those in-service anomalies that are deemed to be a safety risk. Such an allowance is not currently provided under § 192.715 for in-service transmission weld anomalies. Not all weld anomalies found on in-service pipelines are considered unsafe, especially when considering system conditions. For example, planar defects are generally considered more detrimental than volumetric defects in welds. Planar defects such as cracks, lack of penetration/fusion, etc. can act as stress risers where stress is concentrated at the tip of the defect, thereby making the weld more susceptible to fracture; while volumetric defects like porosity and slag are three-dimensional, and act more like inclusions. Although volumetric defects can weaken the weld, they do not necessarily concentrate stress in the same way as planar defects, and (depending on system conditions) could remain in service safely.

If analysis of weld anomalies (in accordance with § 192.712) was available, operators would have the ability to identify predicted failure pressures, and then properly identify welds that require repair. This would decrease the amount of maintenance expenses incurred by the current requirement to repair all weld anomalies. Specifically, certain minor weld anomalies (such as the volumetric defects described above) found on in-service pipelines would no longer require the burdensome repair requirements of § 192.715, which for many operators result in the installation of a full encirclement welded split sleeve at the anomaly. This type of sleeve can cost operators hundreds of thousands of dollars in maintenance expense per weld. Such costs could be avoided entirely if such minor anomalies were allowed to be analyzed in accordance with § 192.712 and deemed to be safe for continued operation.

It is, therefore, AGA's recommendation that §192.715 should allow for analysis of predicted failure pressures and critical strain levels (§192.712) in lieu of the currently illogical tie back to the new construction standard of §192.241.

Weld Repairs:

§ 192.715(c) offers a singular option to repair weld anomalies, for in-service transmission pipelines which cannot be taken out of service or have the pressure reduced. For many distribution pipeline operators operating transmission pipelines within the distribution system (i.e., segments operating ≥20% SMYS), taking a critical pipeline out of service or reducing pressure is not operationally feasible. Therefore, the only repair available under § 192.715(c) is a full encirclement split sleeve.

Contradictory to this singular in-service repair solution, Subpart O incorporates by reference ASME B31.8S-2018 "Supplement to B31.8 on Managing System Integrity of Gas Pipelines". This standard is also incorporated by reference in the above-mentioned transmission repair criteria via § 192.714(c) and (d).

ASME B31.8S-2018, section 7 outlines repair methods which eliminate unsafe conditions, with Table 4 of that section listing out various acceptable threat prevention and repair methods. Within that table are various repair methods for defective pipe girth welds. Repair methods approved for use in ASME B31.8S-2018 but not approved per § 192.715(c) include epoxy filled sleeves and composite wrap sleeves. Such repair methods are less costly and less operationally burdensome than the current requirements of § 192.715(c).

Additionally, in alignment with ASME B31.8S-2018, ASME PCC-2-2022 *Repair of Pressure Equipment and Piping* provides the necessary design basis requirements for various repair methods, specifically used for equipment after it has been placed into service. These two ASME standards complement each other to determine and justify – by relevant design criteria – the appropriate repair method selection. Therefore, PHMSA should incorporate PCC-2-2022 by reference (§§ 192.7, 192.715(c)) and modify § 192.715(c) to reference ASME B31.8S-2018 and ASME PCC-2-2022.

These additional repair methods, while fully acceptable by the above-mentioned standards, are also less costly than the current requirements of § 192.715(c). A full encirclement split sleeve has high excavation, material and installation costs, when compared to the installation requirements associated with alternative methods (such as composite repair sleeves). Therefore, this recommendation not only aligns with industry standard practices, but also provides cost saving on a case-by-case basis.

AGA therefore recommends the following amendments to the regulatory text, along with accompanying changes to § 192.7:

§ 192.715 Transmission lines: Permanent field repair of welds.

~~Each weld that is unacceptable under § 192.241(c)~~ Weld anomalies that have been deemed to impair the serviceability of the pipeline, in accordance with §192.712, must be repaired as follows:

…

(c) A defective weld which cannot be repaired in accordance with paragraph (a) or (b) of this section must be repaired by installing a full encirclement welded split sleeve of appropriate design, or in accordance with ASME B31.8S-2018 or ASME PCC-2-2022.

8. Personnel Qualification and Training Requirements

Question 8:

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.

AGA recommends amending § 192.285(c) to allow for re-qualification under electrofusion and mechanical joint procedures that consist of demonstrating the appropriate procedure and steps related to joint production, without completing the joint. While the employee would still be required to show mastery of the steps of completing a joint, the change would reduce costs as well as the amount of waste sent to landfills. One natural gas distribution operator estimates annual cost savings of roughly $200,000-$300,000 annually without reducing safety. This cost analysis is based on the annual operator qualification costs for internal departments as well as associated contractor costs. Extrapolating this estimate, AGA estimates potential annual cost savings of up to $75 million dollars for gas distribution operators.

The following is the language that AGA proposes to change for § 192.285(c).

§192.285 Plastic pipe: Qualifying persons to make joints.

…

(c) A person must be re-qualified under an applicable procedure once each calendar year at intervals not exceeding 15 months ~~or after any production joint is found unacceptable by testing under §192.513.~~

(1) For plastic pipe electrofusion joints, the re-qualification shall include demonstrating the appropriate knowledge and skills needed for each joint assembly and procedure and may exclude energizing the electrofusion fitting.

(d) A person must be re-qualified in accordance with (a) and (b) prior to any additional joints being produced if a production joint is found unacceptable by testing under §192.513.

~~(d)~~(e) Each *operator* shall establish a method to determine that each person making joints in plastic pipelines in the operator's system is qualified in accordance with this section.

~~(e)~~(f) For transmission pipe installed after July 1, 2021, records demonstrating each person's plastic pipe joining qualifications at the time of construction in accordance with this section must be retained for a minimum of 5 years following construction.

9. Integrity Management Requirements

Question 9:

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.

Revisions to Subpart O (and associated Subpart M requirements)

Requirements for using Direct Assessment for Stress Corrosion Cracking / Additional Preventive and Mitigative Measures – Dents with Metal Loss

AGA recommends aligning anomaly response regulations with advances in technology and providing an engineering analysis alternative for managing dents with metal loss. This recommendation is supported by the justification that revising the regulations would reduce the burden on operators and improve regulatory efficiency. AGA's recommendations specific to anomaly responses are discussed under topic #7 of the PSR topics.

Moreover, both of these sections call out Subpart J hydrostatic pressure testing. § 192.624(c) draws an equivalency between hydrostatic pressure testing, engineering critical assessment (ECA), and alternative technology. Therefore, §§ 192.929 and 192.935 should be amended to allow these methods.

Furthermore, preventive and mitigative measure requirements in §192.935(b)(iv) and §192.935(d)(2) should be modified to allow use of in-line inspection data and other means to evaluate unmonitored excavations. Alternative methods can be more cost effective than those outlined in the current PSR.

Finally, risk analysis and assessments associated with rupture-mitigation valves are required to be reviewed annually. Laying in additional risk analysis and assessment requirements (e.g., within 3 months of an incident or safety related condition) have not been demonstrated to drive meaningful safety outcome improvements, and may distract operators from focusing on the imminent needs associated with the incident or safety related condition. AGA recommends § 192.935(f) be modified to eliminate these additional review deadlines.

§ 192.929 What are the requirements for using Direct Assessment for Stress Corrosion Cracking (SCCDA)?

…

(b)(4) Remediation and mitigation. If SCC is discovered in a covered pipeline segment, an operator must mitigate the threat in accordance with one of the following applicable methods:

(i) Removing the pipe with SCC; remediating the pipe with a Type B sleeve; performing hydrostatic testing in accordance with paragraph (b)(4)(ii) of this section; engineering critical assessment in accordance with §192.632; or alternative technology in accordance with §192.624(c)(6); or by grinding out the SCC defect and repairing the pipe. If an operator uses grinding for repair, the operator must also perform the following as a part of the repair procedure: nondestructive testing for any remaining cracks or other defects; a measurement of the remaining wall thickness; and a determination of the remaining strength of the pipe at the repair location that is performed in accordance with § 192.712 and that meets the design requirements of §§ 192.111 and 192.112, as applicable. The pipe and material properties an operator uses in remaining strength calculations must be documented in traceable, verifiable, and complete records. If such records are not available, an operator must base the pipe and material properties used in the remaining strength calculations on properties determined and documented in accordance with § 192.607, if applicable.

§ 192.935 What additional preventive and mitigative measures must an operator take?

(a) General requirements.

(1) An *operator* must take additional measures beyond those already required by this part to prevent a *pipeline* failure and to mitigate the consequences of a pipeline failure in a *high consequence area*. Such additional measures must be based on the risk analyses required by § 192.917. Measures that operators must consider in the analysis, if necessary, to prevent or mitigate the consequences of a pipeline failure include, but are not limited to:

…

(ix) Conducting hydrostatic tests, <u>engineering critical assessment in accordance with § 192.632, or alternative technology in accordance with 192.624(c)(6),</u> in areas where pipe material has quality issues or lost records;

…

(b) Third party damage and outside force damage-

...

(iv) Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If an operator finds physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, ~~an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE SP0502 (incorporated by reference, see §192.7). An operator must excavate, and remediate, in accordance with ASME B31.8S and §192.933 any indication of coating holidays or discontinuity warranting direct examination.~~ <u>an operator must conduct a follow-up investigation to determine if mechanical damage has occurred. Examples of follow-up investigations include, but are not</u>

limited to, a coating survey or in-line inspection during the next scheduled integrity assessment.

...

(d) Pipelines operating below 30% SMYS. An operator of a transmission pipeline operating below 30% SMYS located in a high consequence area must follow the requirements in paragraphs (d)(1) and (d)(2) of this section. An operator of a transmission pipeline operating below 30% SMYS located in a Class 3 or Class 4 area but not in a high consequence area must follow the requirements in paragraphs (d)(1), (d)(2) and (d)(3) of this section.

...

(2) Either monitor excavations near the pipeline, or conduct patrols as required by §192.705 of the pipeline at bi-monthly intervals. If an operator finds any indication of unreported construction activity, the operator must conduct a follow up investigation to determine if mechanical damage has occurred. Examples of follow-up investigations include, but are not limited to, a coating survey or in-line inspection during the next scheduled integrity assessment.

...

(f) Periodic evaluations. Risk analyses and assessments conducted under paragraph (c) of this section must be reviewed by the operator and certified by a senior executive of the company, for operational matters that could affect rupture-mitigation processes and procedures. Review and certification must occur once per calendar year, with the period between reviews not to exceed 15 months~~, and must also occur within 3 months of an incident or safety-related condition, as those terms are defined at §§ 191.3 and 191.23, respectively~~.

Identifying potential threats to pipeline integrity and using the threat identification in integrity programs – Hydrostatic Testing as sole Subpart J test for addressing manufacturing and construction defects

PHMSA should also amend § 192.917(e)(3) to remove the word "hydrostatic." This would allow both hydrostatic and pneumatic Subpart J pressure tests for determining if manufacturing or construction defects exist that would cause a failure if the requirements of 49 CFR Part 192 Subpart J *Test Requirements* are met.

The language in § 192.917(e)(3) (promulgated under RIN 1) requires operators to conduct a hydrostatic test at least 1.25 times the MAOP in order to demonstrate that manufacturing and construction defects are stable. This requirement has created confusion, since Subpart J allows a pneumatic (gaseous medium; e.g., natural gas, air, or inert gas) pressure test for new or replaced pipelines. These pressure tests achieve the same outcome as the hydrostatic pressure tests prescribed in § 192.917(e)(3); namely whether critical defects to the integrity of the pipeline do or do not exist.

Note that Subpart J test requirements include conservative conditions when a pneumatic test is permitted to be performed, as seen in the allowable maximum hoop stress limits (as a percentage of SMYS) defined in § 192.503(c). These limitations ensure the tested pipe is subject to lower hoop stresses and an increased level of safety during pressure testing. These conservative parameters have proven to be safe and effective.

In the preamble to RIN 1[38], PHMSA stated:

> …
>
> (2) When considering the IM clarifications at § 192.917, the GPAC recommended PHMSA consider removing the term ‘‘hydrostatic’’ from the testing requirements at § 192.917(e)(3), which deals with manufacturing and construction defects, and allow other authorized testing procedures. PHMSA is not implementing this recommendation because allowing pneumatic tests would be a safety concern to the public and operating personnel.
>
> …

PHMSA provided no information to support their position that performing a Subpart J test using natural gas, air, or inert gas as the test medium (pneumatic pressure testing) is a safety concern to the public and operating personnel. In fact, pneumatic testing of transmission lines has been safely performed in accordance with Subpart J requirements for over 50 years. This has been indirectly acknowledged by PHMSA in declining to amend Subpart J requirements to prohibit pneumatic testing for transmission lines.

Furthermore, a transmission line’s MAOP may result in a hoop stress below 20% SMYS (e.g., if voluntarily designated as “transmission line” by the operator under § 192.3). Even for these pipelines, § 192.917(e)(3) would require a hydrostatic test.

[38] “Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments.” 87 FR 52224. August 24, 2022.

In summary, allowing the use of pneumatic testing in § 192.917(e)(3) would be consistent with the Subpart J requirements. AGA estimates an annual estimated cost savings of $30-50 million if this allowance is made.

PHMSA should amend 49 CFR § 192.917(e)(3) as follows:

> **§192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?**
>
> …
>
> (e)(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 either ~~hydrostatic~~ pressure testing satisfying the criteria of subpart J of at least 1.25 times MAOP, engineering critical assessment in accordance with §192.632, or alternative technology in accordance with §192.624(c)(6) 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, engineer critical assessment, or application of alternative technology. 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, engineering critical assessment, or application of alternative technology due to an original manufacturing-related defect, or a construction-, installation-, or fabrication-related defect;

Baseline Assessments – Newly Active/Identified Threats

49 CFR § 192.939 prescribes the reassessment intervals for active threats identified during an initial assessment but does not specify the timing for a new threat that becomes active on a covered segment during a reassessment. In 2021, PHMSA responded to an inquiry from PG&E requesting clarification on this topic[39], which was particularly relevant due to both an advisory bulletin issued in 2017 by PHMSA regarding threat deactivation [40] as well as the promulgation of RIN 1, which required Subpart J pressure tests to consider manufacturing and construction threats stable, resulting in the activation of threats previously considered stable[41].

However, PHMSA's guidance appears to blend two distinct concepts: (1) the identification of threats that have not been confirmed, and (2) discovery of anomalous conditions. Generally, an operator identifies threats on a pipeline in advance of executing an integrity assessment by reviewing historical and other data about a pipeline. Threats could be based on historical findings (e.g., discovered condition) or could be theoretical based on data evaluation. Where a threat becomes "newly active," particularly as a result of regulatory actions rather than historical conditions, the addition of the threat should be treated as theoretical and managed similarly to instances where a pipeline segment is newly added to the TIMP. PHMSA currently allows operators up to 10 years to assess pipe in a newly identified HCA – pipe that may not have been assessed previously – recognizing that it may take operators time to gather data and plan and execute an assessment.[42] PHMSA should likewise allow operators up to 10 years or the next reassessment cycle – whichever is sooner – to evaluate a newly active threat. This recommendation has also been made in the comments filed by INGAA, AGA, and GPA in response to PHMSA's "Pipeline Safety: Repair Criteria for Hazardous Liquid and Gas Transmission Pipelines" ANPRM.[43]

The distinction of a newly activated threat as a result of regulatory action (i.e., theoretical) and the discovery of a condition (i.e., evidenced) is a critical distinction that PHMSA should clarify in its guidance on assessing new threats, which should then be incorporated into the PSR. In the absence of this distinction, costs associated with

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[39] PHMSA Interpretation Response PI-21-0004; https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/standards-rulemaking/pipeline/interpretations/75361/pacific-gas-and-electric-company-pi-21-0004-06-24-2021-part-192939.pdf

[40] Pipeline and Hazardous Materials Safety Administration. (March 16, 2017). *Pipeline Safety: Deactivation of Threats*, 82 Fed. Reg. 14,106. U.S. Department of Transportation, https://www.federalregister.gov/documents/2017/03/16/2017-05262/pipeline-safety-deactivation-of-threats

[41] 49 CFR § 192.917(e)

[42] Final Gas IM FAQs (https:// www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2021-09/Final%20GAS%20IM%20FAQs%208-26-21.pdf)

[43] 2025-07-21- INGAA_AGA_GPA_Associations Comments on PHMSA Repair Criteria ANPRM (https://downloads.regulations.gov/PHMSA-2025-0019-0022/attachment_1.pdf)

TIMP have increased substantially for operators within a period of just a few years. Rather than methodically incorporating the assessment of newly active threats (such as stress corrosion cracking – SCC – threats) to balance system reliability and ratepayer impacts, operators must quickly adjust project scopes; secure inspection resources, permits, materials; and complete the assessment ahead of reassessment deadlines which, in some cases, are less than a year from the time of "activation."

For example, one operator has seen cost increases of $30-40 million in a single year as a result of expediting additional assessment work to address newly-active threats. Moreover, the obligation to assess newly activated threats within the same cycle can interfere with established operations and maintenance schedules, compounding the logistical challenges and potentially reducing overall pipeline management efficiency. The burdens imposed by these constraints are further exacerbated by the limitations associated with obtaining permits, 6-month extensions outlined in 49 CFR § 192.939(a) and (b) [32], as well as waivers specified in 49 CFR § 192.432. If newly activated threats need to be assessed within the current cycle, operators must accelerate the reassessment time period, impacting the need for permits, extensions, and waivers, while incurring additional costs. Allowing reassessments in the next cycle would help alleviate the additional costs for operators and customers.

In summary, PHMSA should withdraw PI-21-0004 and amend 49 CFR § 192.921 as follows:

§ 192.921 How is the baseline assessment to be conducted?

...

(f) Newly identified threats or areas. When an operator identifies a new high consequence area (see § 192.905) or a new threat in an existing high consequence area (see § 192.917), an operator must complete a threat-specific ~~the~~ baseline assessment of the line pipe ~~in the newly identified high consequence area~~ within ten (10) years from the date the area or threat is identified.

Required Reassessment Intervals

AGA recommends that PHMSA provide a 6-month "grace period" in the reassessment interval (e.g., one-year intervals not to exceed 15 months) prescribed in 49 CFR § 192.939(a) and (b), rather than requiring a separate extension request. Embedding the extension into the regulation would streamline compliance efforts by eliminating the need for operators to prepare and submit formal extension requests, which are administratively burdensome and time-consuming. Throughout the CFR, there are other time-based requirements where PHMSA allows operators additional time beyond a deadline to complete the required activity. For example, 49 CFR § 192.710(b)(2) requires operators to perform periodic reassessments every 10 years, with **intervals not to exceed 126 months**, effectively allowing a 6-month extension without the need for a request. However, § 192.939(a) and (b) stipulate a 7-year interval and require a formal request to PHMSA to utilize a 6-month extension.

Currently, to submit a request, operators must provide sufficient justification. Extension requests are primarily necessary due to permitting processes and constraints resulting from new scopes of work identified towards the end of reassessment intervals, but may also come about as a result in newly-promulgated regulations and interpretations. On average, one operator estimates that $22,400 to $25,600 was spent annually on requesting extensions. AGA believes that integrating the 6-month extension into the standard reassessment interval would enhance regulatory consistency, reduce administrative overhead, and better reflect the realities of pipeline operations and planning.

PHMSA should formally incorporate a 6-month extension into the standard reassessment process, both for consistency and to reduce the burden on operators who need this additional time. Additionally, PHMSA should allow operators to request an extension of the reassessment deadline by 1 year (i.e., an additional 6 months) if factors outside of the operator's control (e.g., permitting, severe weather events) render the operator incapable of completing the assessment within 90 months. This would support PHMSA's expectations that operators assess newly discovered conditions within the assessment cycle, regardless of whether that condition is discovered towards the end of the cycle, and harmonize Subpart O with the newer requirements of 49 CFR §192.624, which allows operators an additional year to reconfirm the MAOP of a pipeline if "operational and environmental constraints limit an operator from meeting the deadlines."

§ 192.939 What are the required reassessment intervals?

…

(a) Pipelines operating at or above 30% SMYS**.** An operator must establish a reassessment interval for each covered segment operating at or above 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is 7 calendar years, not to exceed 90 months. Operators may request a 6-month extension of the ~~7-calendar-year~~ reassessment interval if the operator submits written notice to OPS, in accordance with § 192.18, with sufficient justification of the need for the extension. If an operator establishes a reassessment interval that is greater than 90 months ~~7 calendar years,~~ the operator must, within the 90-

month period ~~7 calendar year period~~, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with § 192.931. The table that follows this section sets forth the maximum allowed reassessment intervals.

…

(b) Pipelines Operating below 30% SMYS. An operator must establish a reassessment interval for each covered segment operating below 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is 7 calendar years, not to exceed 90 months. Operators may request a 6-month extension of the ~~7 calendar year~~ reassessment interval if the operator submits written notice to OPS in accordance with § 192.18. The notice must include sufficient justification of the need for the extension. An operator must establish reassessment by at least one of the following—

Similarly, AGA recommends adding this 6-month extension to 49 CFR § 192.710 for consistency:

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

...

(b) ***General*** —

(1) *Initial assessment.* An operator must perform initial assessments in accordance with this section based on a risk-based prioritization schedule and complete initial assessment for all applicable pipeline segments no later than July 3, 2034, or as soon as practicable but not to exceed 10 years after the pipeline segment first meets the conditions of § 192.710(a) (*e.g.,* due to a change in class location or the area becomes a moderate consequence area), whichever is later.

(2) *Periodic reassessment.* An operator must perform periodic reassessments at least once every 10 years, with intervals not to exceed 126 months, or a shorter reassessment interval based upon the type of anomaly, operational, material, and environmental conditions found on the pipeline segment, or as necessary to ensure public safety. Operators may request a 6-month extension of the reassessment interval if the operator submits written notice to OPS in accordance with § 192.18.

Deviation from Reassessment Intervals

As discussed previously, 49 CFR § 192.939 mandates periodic reassessments of pipeline segments located in High Consequence Areas (HCAs) to identify and address potential threats. Recognizing that assessments within fixed intervals may not always be feasible, PHMSA currently provides operators with a pathway to request a waiver, but restricts waiver requests to two scenarios: (1) a lack of internal inspection tools, and (2) in order to maintain product supply. These provisions were originally intended to offer flexibility in rare, well-justified cases where reassessment could not be completed within the prescribed timeframe without compromising safety or service. However, the scope of these waiver provisions has not evolved to reflect the broader range of challenges operators face in the field.

AGA recommends that PHMSA expand the list of allowable waiver circumstances with a third option to include uncontrollable situations such as permitting delays (e.g., environmental or land use approvals), severe weather events (e.g., floods, wildfires, hurricanes), and other factors outside of the operator's control. These factors can significantly delay reassessment activities despite an operator's best efforts to remain in compliance. Requiring adherence to the current reassessment interval without flexibility for such events may result in operators finding themselves out of compliance due to factors beyond their control, as well as being pressured to conduct rushed, inefficient work. Additionally, AGA recommends the waiver process under 49 CFR § 192.943 be triggered only after the 6-month extension allowed under 49 CFR § 192.939 has been exhausted. This would ensure that operators have a reasonable window to complete reassessments while maintaining safety and regulatory intent.

§ 192.943 When can an operator deviate from these reassessment intervals?

(a) Waiver from reassessment interval in limited situations. In the following limited instances, OPS may allow a waiver from a reassessment interval required by § 192.939 if OPS finds a waiver would not be inconsistent with pipeline safety.

(1) Lack of internal inspection tools. An operator who uses internal inspection as an assessment method may be able to justify a longer reassessment period for a covered segment if internal inspection tools are not available to assess the line pipe. To justify this, the operator must demonstrate that it cannot obtain the internal inspection tools within the required reassessment period and that the actions the operator is taking in the interim ensure the integrity of the covered segment.

(2) Maintain product supply. An operator may be able to justify a longer reassessment period for a covered segment if the operator demonstrates that it cannot maintain local product supply if it conducts the reassessment within the required interval.

(3) *Uncontrollable factors.* An operator may be able to justify a longer reassessment period if the operator demonstrates that uncontrollable circumstances such as permitting delays (e.g., environmental or land use approvals), severe weather events (e.g., floods, wildfires, hurricanes), or other factors outside of the operator's control are preventing the operator from conducting the reassessment within the required interval.

…

10. LNG Siting Requirements

Question 10: 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.

AGA does not have specific comments on LNG siting requirements at this time.

11. Drug and Alcohol Testing Requirements

> **Question 11:**
>
> 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.

Revisions to 49 CFR 199 – Subpart B

Drug Tests Required – Random Testing

AGA recommends that drug testing protocols be operator-specific, based on individual positive response rates to reduce undue burdens. AGA fully supports the safeguards that 49 CFR 40 Procedures for Transportation Workplace Drug and Alcohol Testing Programs provide, but suggests that individual operators whose annual testing results would qualify them to test 25% of their covered employes based on a less than 1.0% positive rate should not have to bear the burden of testing at a higher rate if the industry as a whole breaches the 1.0% threshold. Only operators whose positive rate is greater than or equal to 1.0% should be required to test at the increased rate.

For example, in 2024 one AGA member company tested 397 covered employees resulting in 2 positive tests and 1 refusal, for a 0.755% (i.e., less than 1%) positive rate. With the increased annual percentage rate of random tests in 2025, they are now required to test approximately 800 covered employees. This operator's average cost for each 5-panel test in 2024 was $32. The additional tests increased the operator's spend by $12,800 for testing services. These costs do not include company labor to administrate the additional tests or the lost time by the covered employee to complete the process in 2025.

Drug and Alcohol Management Information System Report (DAMIS) information on positive testing results and total tests by individual operator is not publicly available. However, it is reasonable to project that an operator who would otherwise qualify to test 25% of their employees but has to meet a 50% criteria due to the industrywide positive test rate would incur double the cost of not only testing, but administrative costs and lost time, and without any discernible safety benefit.

PHMSA's current random testing regulations also requires an employee – selected for a random drug test and unavailable on the date the employer intended for the test to be completed – to be tested at some time after the employee becomes available. The timeframe for an employee to return to work after being unavailable could vary from a few days to over a year depending on the cause of their unavailability. However, current regulations require that when the employee becomes available, the employer must make up the missed tests within that calendar year. This creates an administrative burden on the employer to track employees who are rolled over throughout the year. If an employer fails to complete all missed tests, they are out of compliance with PHMSA drug and alcohol testing requirements and subject to disciplinary action.

PHMSA should consider adopting the Federal Motor Carrier Safety Administration (FMCSA) drug and alcohol regulations found in 49 CFR § 382.305 (i)(3), which states that *each driver (i.e., person) selected for testing shall be tested during the selection period*. This would mean that an employer would not have to roll over employees who were unable to test during a selection cycle. Amending the regulations to only allow random testing during a selection period would eliminate the requirement to rollover and relieve the employer from any undue burdens.

AGA recommends that PHMSA revise the language within § 199.105(c) as follows:

§199.105 Drug test required.

…

(c) Random testing.

(1) ~~Except as provided in paragraphs (c)(2) through (4) of this section, the minimum annual percentage rate for random drug testing shall be 50 percent of covered employees.~~Effective January 1 of each calendar year, operators shall establish the minimum annual percentage rate for random testing of their covered employees for that calendar year in accordance with paragraphs (c)(2) and (c)(3).

(2) ~~The Administrator's decision to increase or decrease the minimum annual percentage rate for random drug testing is based on the reported positive rate for the entire industry. All information used for this determination is drawn from the drug MIS reports required by this subpart. In order to ensure reliability of the data, the Administrator considers the quality and completeness of the reported data, may obtain additional information or reports from operators, and may make appropriate modifications in calculating the industry positive rate. Each year, the Administrator will publish in the Federal Register the minimum annual percentage rate for random drug testing of covered employees. The new minimum annual percentage rate for random drug testing will be applicable starting January 1 of the calendar year following publication.~~If an operator’s reported positive rate is less than 1.0 percent for the two consecutive preceding

calendar years under the reporting requirements of § 199.119, the annual percentage rate for random drug testing shall be 25 percent of all covered employees for the current calendar year.

(3) ~~When the minimum annual percentage rate for random drug testing is 50 percent, the Administrator may lower this rate to 25 percent of all covered employees if the Administrator determines that the data received under the reporting requirements of § 199.119 for two consecutive calendar years indicate that the reported positive rate is less than 1.0 percent.~~If an operator's reported positive rate does not meet the requirements of paragraph (c)(2) under the reporting requirements of § 199.119, the annual percentage rate for random drug testing shall be 50 percent of all covered employees for the current calendar year. The 50 percent testing rate shall continue until the operator meets the requirement of paragraph (c)(2).

(4) ~~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 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.~~

…

(5) The selection of employees for random drug testing shall be made by a scientifically valid method, such as a random number table or a computer-based random number generator that is matched with employees' Social Security numbers, payroll identification numbers, or other comparable identifying numbers. Under the selection process used, each covered employee shall have an equal chance of being tested each time selections are made. Each person selected for testing shall be tested during the selection period.

III. Conclusion

AGA appreciates the opportunity to provide comments on this ANPRM and looks forward to working with PHMSA to develop regulations that enhance pipeline safety while minimizing undue burdens on operators. AGA is committed to ensuring the safe and reliable delivery of natural gas and believe that these recommendations will help achieve that goal.

Respectfully submitted
Date: August 4, 2025

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