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

Pipeline Safety: Meeeting of the Gas Pipeline Advisory Committee	}	Docket No. PHMSA-2024-0005

COMMENTS IN RESPONSE TO NOTICE OF MEETING OF GAS PIPELINE ADVISORY COMMITTEE

FILED BY
INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA
AMERICAN PUBLIC GAS ASSOCIATION
AMERICAN GAS ASSOCIATION
AMERICAN PETROLEUM INSTITUTE
GPA MIDSTREAM ASSOCIATION

August 27, 2024

Table of Contents

I. Introduction

The Interstate Natural Gas Association of America (INGAA),[1] the American Public Gas Association (APGA),[2] the American Gas Association (AGA),[3] the American Petroleum Institute (API),[4] and the GPA Midstream Association (GPA)[5] collectively, the Associations, respectfully submit these comments in response to the Pipeline and Hazardous Materials Safety Administration's (PHMSA or the Agency) Notice of Gas Pipeline Advisory Committee Meeting (the Notice).[6]

The Associations submit these comments in response to the Notice concerning the Gas Pipeline Advisory Committee (the GPAC) meeting conducted between March 25, 2024, and March 29, 2024 (the Meeting). While the Meeting covered both the Gas Pipeline Leak Detection and Repair Rule (LDAR) and the Class Location Change Requirements (Class NPRM)[7] Notices of Proposed Rulemakings, these comments focus exclusively on the discussion of the Class NPRM at the Meeting.

As the Agency proceeds to finalize the Class NPRM, it has a significant opportunity to modernize the pipeline safety regulations. In these comments, the Associations highlight the potential advancements to pipeline safety, reliability, and methane emissions savings the Class Final Rule

---

[1] INGAA is comprised of 27 members, representing the vast majority of the U.S. interstate natural gas transmission pipeline companies. INGAA's members operate nearly 200,000 miles of pipelines and serve as an indispensable link between natural gas producers and consumers.

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

[3] 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.

[4] API is the national trade association representing all facets of the oil and natural gas industry, which supports 10.3 million U.S. jobs and 8 percent of the U.S. economy. API's nearly 600 members include large integrated companies, as well as exploration and production, refining, marketing, pipeline, and marine businesses, and service and supply firms. They provide most of the nation's energy and are backed by a growing grassroots movement of millions of Americans.

[5] GPA Midstream has served the U.S. energy industry since 1921 and represents over 50 domestic corporate members that directly employ 57,000 employees that are engaged in the gathering, transportation, processing, treating, storage, and marketing of natural gas, natural gas liquids, crude oil, and refined products, commonly referred to as "midstream activities." The work of our members indirectly creates or impacts an additional 400,000 jobs across the U.S. economy. In 2023, GPA Midstream members operated over 250,000 miles of gas gathering pipelines, gathered over 91 billion cubic feet per day of natural gas, and operated over 365 natural gas processing facilities that delivered pipeline quality gas into markets across a majority of the U.S. interstate and intrastate pipeline systems.

[6] Pipeline Safety: Meeting of the Gas Pipeline Advisory Committee, 89 Fed. Reg. 12,798 (Feb. 20, 2024). On April 15, 2024, PHMSA extended the comment period to August 27, 2024. *See* Pipeline Safety: Meeting of the Gas Pipeline Advisory Committee, 89 Fed. Reg. 26,118 (Apr. 15, 2024).

[7] Pipeline Safety: Class Location Change Requirements, 85 Fed. Reg. 65,142 (Oct. 14, 2020), *hereinafter* "Class NPRM".

could promote. The current class location change requirements reflect the technologies and approaches to pipeline safety available in the 1950s and are now outdated.[8] Instead, extending the use of integrity management to class location changes will advance pipeline safety, increase reliability, and produce tangible environmental benefits. The success of the integrity management requirements in Part 192, Subpart O clearly demonstrates that operators can manage risk with far more precise systems and technologies than what existed when the code was initially implemented over fifty years ago. PHMSA has expanded integrity management beyond high consequence areas and the same approach should be applied to class location changes to avoid unnecessary pipe replacements and significant emissions to the environment.

As discussed at the Meeting, by extending integrity management requirements to class location changes, operators will be able to redeploy resources from unnecessary projects, such as pipe replacements, to projects that can meaningfully advance safety and reduce emissions.[9] Introducing an integrity management alternative to the class location change requirements will mitigate the need to replace safe pipelines producing a significant environmental benefit. Eliminating these unnecessary replacements could reduce methane emissions by approximately 287,000 metric tons over a 15-year period.[10] This total is 28 times the amount of methane savings estimated by PHMSA for the implementation of the proposed LDAR rule.[11] The magnitude of emissions savings available through class location reform is exceptional and would align with the Agency and industry's objectives to reduce methane emissions and improve pipeline safety with modern pipeline risk management requirements established by current regulations.

Operators would also be able to improve the reliability of service by avoiding unnecessary shutdowns and pressure reductions.[12] Improved reliability will help meet rising energy demand and reduce the need to construct new infrastructure. Permitting operators to employ an integrity management approach after a class location change will promote consistency and eliminate the uncertainty of the timing with the special permit process, while maintaining stringent eligibility criteria and minimizing disruptions to energy deliverability.

The Class Final Rule should capture the recent amendments and improvements made to the Part 192 integrity management requirements. While PHMSA published the Class NPRM in 2020, since

---

[8] As acknowledged by PHMSA at the Meeting, the class location concept goes back to 1955. Meeting of Gas Pipeline Advisory Committee, Transcript at 9:1-4 (Mar. 27, 2024), https://primis-meetings.phmsa.dot.gov/meetings/f64a12c1-01fc-444d-9ffa-d0ea90bc314d/files/ebdd542f-0804-4645-81b6-dcbb3edb4288/PHMSA_Day_3_Class_Location_Requirements_Transcript_03272024.pdf
[9] *Id.* at 78:7-17.
[10] *Id.* at 64:15-19.
[11] *Id.* at 64:10-14 (INGAA calculated the methane savings by converting its previous estimate of 800 mmscf of natural gas released each year due to class location changes to metric tons which equates to approximately 287,000 metric tons. This total is 28 times the amount of methane that PHMSA estimates will be saved by the transmission sector as a result of the LDAR NPRM (see LDAR PRIA)).
[12] *Id.* at 134:5-22.

that time, the Agency finalized the RIN-1,[13] RIN-2,[14] and valve rulemakings,[15] which made significant amendments to Subpart O. Operators have successfully begun to implement those new requirements, demonstrating their efficacy, and advancing pipeline safety. The Class Final Rule should build on these technically supported amendments, rather than revert to the Class NPRM proposal. Proposed section 192.618 adds conflicts, complication, and redundancy to the regulations on top of existing Subpart O and recent amendments as part of the valve, RIN-1, RIN-2 rulemakings. For example, RIN-2 introduced more specific anomaly identification and repair requirements. Referencing Subpart O requirements in place of the Class NPRM is the most effective way to implement rigorous current pipeline safety requirements, as well as future stringent Subpart O regulations. PHMSA acknowledged the interplay between these rules and agreed to review the Class Final Rule for inconsistencies.[16] Given the extensive modifications of Part 192 since the Class NPRM was first introduced, the Associations are also providing consolidated revisions to the regulatory text for the Agency's review and consideration.[17]

II. Scope, Applicability, and Notification Requirements

A. PHMSA should not include a public notification requirement for operators seeking to use the integrity management option for class location changes.

The Class Final Rule offers a unique opportunity for pipeline operators to increase safety while also reducing or eliminating disruptions to landowners and the affected public associated with proving the safety or integrity of pipelines when population increases occur. These outdated methods include replacing hundreds of miles of pipe or conducting hundreds of hydrostatic tests per year. By adopting the changes contained throughout this comment document, the vast majority of these disruptions will no longer be necessary.

PHMSA initially proposed an addition to section 191.22 which, if included in the Class Final Rule, would require operators to notify the Agency if they chose to use the integrity management alternative.[18] This proposal was not discussed by the GPAC.

At the Meeting, several GPAC members recommended that PHMSA consider incorporating a more expansive notification process requiring operators to notify individual landowners located

[13] Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation; Expansion of Assessment Requirements, and other Related Amendments, 84 Fed. Reg. 52,180 (Oct. 1, 2019).
[14] Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments, 87 Fed. Reg. 52,224 (Aug. 24, 2022).
[15] Pipeline Safety: Requirement of Valve Installation and Minimum Rupture Detection Standards, 87 Fed. Reg. 20,940 (April 8, 2022).
[16] *See* "Class Location-GPAC Presentation Slide Deck for Members and Public," at 22 https://www.regulations.gov/document/PHMSA-2024-0005-0005; *See also*, GPAC Transcript, at 26:16-19 (Mar. 27, 2024) ("So, if and whenever the class location final rule is ultimately approved and published, you know, we'll be making sure that conforming changes are made for consistency.").
[17] *See* Attachment B.
[18] Pipeline Safety: Class Location Change Requirements, 85 Fed. Reg. 65,142, 65174 (Oct. 14, 2020).

within the pipeline segment's potential impact radius (PIR) of the operator's intent to use the integrity management alternative.[19]

The Associations find this type of notification unnecessary and overly burdensome. The adoption of the provisions set forth in this class location change rulemaking will reduce the impact on the affected public when compared with replacing pipe. In addition, PHMSA already requires operators to develop and implement a public awareness program alerting the affected public of the existence of the pipeline, the commodity the pipeline transports, the possible hazards associated with an unintended release from the pipeline, and the steps to report a possible release.[20] In the event that operators are conducting maintenance work on the pipeline right-of-way adjacent to a specific landowner, a standard practice is to notify the affected public of this work.[21] The Associations are also concerned that such a notification could create unnecessary confusion.

If PHMSA were to codify an integrity management alternative for class location changes, then proceeding with a public notification requirement would amount to operators notifying the affected public that they intend to follow the law. Operators are not required now to notify individual landowners when they are complying with the pipeline safety regulations. Many operators throughout the country voluntarily apply integrity management requirements to pipelines that are not in high consequence areas. Those operators are not required to notify members of the public of their use of integrity management requirements. PHMSA has not provided any rationale for why the integrity management alternative for class location changes should be approached differently.

On account of the paperwork burdens involved, PHMSA will need to seek approval from the Office of Management and Budget for such a notification requirement. Requiring an operator to notify each individual landowner located in the PIR when it intends to use an option allowed by regulation is not "necessary for the proper performance of the functions of the agency" and will create unnecessary delays.[22]

A few GPAC members contended at the Meeting that since the public has an opportunity to comment on proposed class location special permits, they should also be notified that an operator intends to comply with the integrity management alternative. A special permit is an agency order waiving compliance with certain specified regulations.[23] Public notice and comment is appropriate in those situations. In contrast, the integrity management alternative to class location changes will be codified. Throughout the rulemaking process, the public has had ample opportunity to comment on PHMSA's class location proposal.[24] Another notification requirement is not appropriate as it

---

[19] GPAC Voting Slides, at 1, https://primis-meetings.phmsa.dot.gov/meetings/f64a12c1-01fc-444d-9ffa-d0ea90bc314d/files/1f315d77-fc5b-433b-bdc2-b7fa8e5e43fb/Class_Location_NPRM_GPAC_Voting_Slides.pdf.
[20] 49 C.F.R. § 192.616(d)(1)-(5).
[21] For those following the principles of the voluntary API RP 1185, best practices for notifying the affected public of maintenance work will be followed.
[22] 5 C.F.R. § 1320.8(d)(1)(i).
[23] 49 C.F.R. § 190.341(a).
[24] For the Class NPRM, PHMSA initiated the process in 2018 by issuing an Advance Notice of Proposed Rulemaking (ANPRM). *See* Pipeline Safety: Class Location Change Requirements, 83 Fed. Reg. 36,861 (July 31, 2018). The public has had the opportunity to comment on the ANPRM, NPRM, attend the GPAC meeting, and now comment on the GPAC meeting.

simply increases the burden on operators without a commensurate benefit to the public or the agency. For the same reasons, the Associations also do not support PHMSA's proposed changes to section 191.22 which would create an obligation to inform the Agency if an operator chooses to comply with the integrity management alternative.

B. PHMSA should consider including class location changes from a Class 2 to Class 3 in proposed Section 192.618.

PHMSA sought comment on whether Class 2 design pipe with a minimum pressure test of 1.25 x MAOP should be eligible for the integrity management alternative. At the Meeting, the GPAC members unanimously recommended this modification.[25] The Associations also agree that these pipelines should be eligible to use the integrity management option. However, the Associations request that PHMSA also evaluate changes from a Class 2 to Class 3. If a pipe has been pressure tested to at least 1.25 x MAOP, it has achieved the acceptable safety factor to mitigate manufacturing and construction risks under Subpart O.[26]

C. During the next GPAC meeting, PHMSA should initiate discussion covering other class location topics such as the PIR and clustering.

At the Meeting, the GPAC recommended that PHMSA host another meeting within twelve months to discuss further improvements that can be made to the class location change requirements.[27] The Associations are supportive of this recommendation. Certain GPAC members stressed the need to update the regulations to capture methodologies such as the PIR, which would prove to be "much more effective" than "an outdated technique like the sliding mile."[28] INGAA agrees that PHMSA should discuss the use of the PIR in lieu of the 1,320-foot corridor.[29] This 1,320-foot corridor is a remnant from the initial class location rulemaking from the 1970s and is a one-size-fits-all measure that does not strike the right balance between safety and resource deployment. Small diameter and low-pressure pipes do not have a PIR that will extend 1,320 feet, while large diameter and high-pressure pipelines will have a PIR that is greater than 1,320 feet. Instead, PHMSA should explore the use of the PIR, a scientifically proven method, which is used to estimate an individual pipeline's impact radius, manage risk, and prioritize work.[30] The PIR has already been incorporated into Subpart O to help establish the locations of high consequence areas[31] and moderate consequence areas.[32] Its use in the context of class location could serve to further modernize Part 192 and more appropriately apply risk-based approaches to pipelines.

PHMSA should also reevaluate its clustering methodology. In comments filed in response to the Class NPRM, the joint trade associations raised concerns related to the Agency's clustering

---

[25] GPAC Voting Slides, at 2.
[26] 49 C.F.R. § 192.917(e)(3).
[27] GPAC Voting Slides, at 3; *See also,* GPAC Transcript at 79:16:22 and 80:1-2 (Mar. 28, 2024), https://primis-meetings.phmsa.dot.gov/meetings/f64a12c1-01fc-444d-9ffa-d0ea90bc314d/files/2395b971-1477-4e4c-8728-5a4df1c4f142/PHMSA_Day_4_Class_Location_Requirements_Transcript_03282024.pdf,.
[28] GPAC Transcript, Mar. 27, 2024, at 81:20-82:6.
[29] 49 C.F.R. § 192.5(a)(Part 192 establishes class location units by measuring a 220 yard or 660-foot buffer on either side of the centerline.)
[30] GPAC Transcript, Mar. 27, 2024, at 81:11-82:6.
[31] 49 C.F.R. § 192.903; *See also,* 49 C.F.R. § 192.905.
[32] 49 C.F.R. § 192.710.

methodologies,[33] and INGAA reiterated those concerns at the GPAC meeting.[34] Similar to the 1,320-foot corridor, clustering is another outdated element of PHMSA's class location requirements and an area of continued uncertainty for operators. PHMSA should discuss this issue at the next GPAC meeting to establish clarity and allow operators to implement clustering methodologies that are based on risk-based systems and modern technologies. PHMSA should also consider issuing a supplemental notice prior to the next GPAC meeting to accommodate these additional class location topics.

III. Eligibility Criteria

A. PHMSA should not require operators to verify ultimate tensile strength.

In the Class NPRM, PHMSA proposed to disqualify pipeline segments from using the integrity management alternative if the operator was missing certain attributes including tensile strength.[35] At the Meeting, the GPAC members voted unanimously that section 192.618(a) was technically feasible, reasonable, cost-effective, and practicable if operators can use § 192.607 to obtain the missing pipe properties within the 24-month class change period.[36] The GPAC members also recommended that PHMSA consider not requiring the collection of tensile strength information.[37]

The Associations agree with the GPAC recommendation. PHMSA should not require operators to verify tensile strength. Yield strength, not ultimate tensile strength, is the key component driving pipe design and evaluations related to anomaly or MAOP calculations.[38] For anomaly calculations, operators need diameter, wall thickness, seam type, and grade, which indicates specified minimum yield strength (SMYS). The Associations support the use of Section 192.607 to obtain or verify certain material properties for purposes of the integrity management alternative.

B. Operators should be permitted to use Subpart O to evaluate and remediate cracking threats.

In the Class NPRM, PHMSA proposed to disqualify pipe segments that had cracking in the pipe body, seam, or girth welds in or within 5 miles of the Class 1 to Class 3 segment.[39] At the Meeting, the GPAC members recommended that PHMSA consider allowing operators to use Subpart O to inspect for and remediate cracks.[40] The Associations agree with the GPAC recommendation. The purpose of integrity management is to identify, assess, and manage threats, including cracks, in a way that is supported by data and engineering. Section 192.917 already requires operators to take

---

[33] Comments filed by the American Gas Association, American Petroleum Institute, American Public Gas Association, GPA Midstream Association, Interstate Natural Gas Association of America, and NACE International Institute, at 28, PHMSA-2017-0151-0061, (Dec. 14, 2020)("PHMSA should continue to allow a reasonable variety of "cluster" definitions across the industry.").
[34] GPAC Transcript, Mar. 28, 2024, at 311:12-20("INGAA and its member companies have major concerns with how clustering is being interpreted at this point in time. There [are] major concerns on how that could be enforced.").
[35] *See* Proposed Section 192.618(a)(4); *See also*, Class NPRM, at 65,157, 65,175.
[36] GPAC Voting Slides, at 4.
[37] GPAC Transcript, Mar. 28, 2024, at 311: 12-20.
[38] *Id.*, at 317: 3-21.
[39] Proposed section 192.618(a)(4)(vii).
[40] GPAC Voting Slides, at 5.

steps to identify cracking threats, and if a cracking threat is identified, operators must comply with an appropriate assessment process.[41]

Operators have demonstrated that they can successfully use Subpart O to manage cracking threats in high consequence areas,[42] and the application of Subpart O to areas undergoing class location changes will have similar results. There has only been one stress corrosion cracking-related incident in an HCA over the past 15 years.[43] Operators have successfully managed stress corrosion cracking in HCAs through hydrostatic testing and EMAT ILI. Subpart O provides specific measures for evaluating SCC susceptibility, assessment methods for SCC, and evaluation and repair of SCC. Through the RIN-2 rulemaking, PHMSA has now added stringent repair criteria for cracking including a 50% percent depth threshold. In addition, there is a one-year repair threshold that is equivalent to a 100% SMYS hydrostatic test.

There are additional benefits for allowing the use of Subpart O to manage cracking threats within Class 2 and Class 3 (or Class 1 to Class 3) change locations. The mileage of pipe that operators incorporate into their integrity management programs will greatly increase. More pipe than ever before will be assessed and monitored using in-line inspection (ILI) tools. Operators will have increased visibility into cracks, and other threats, throughout their systems, and adopt remediation and repair programs that greatly increase pipeline safety.

C. PHMSA should revise the eligibility restrictions in Section 192.618(a)(4)(viii).

PHMSA proposed to disqualify operators with pipe segments exhibiting "poor external coating" from using the integrity management alternative.[44] The Agency defined "poor external coating" as those pipeline segments requiring a minimum negative cathodic polarization voltage shift of 100 millivolts, linear anodes along a Class 1 to Class 3 segment, or segments with tape wraps or shrink sleeves.[45] GPAC members recommended that PHMSA consider alternatives such as ILI assessments to demonstrate that corrosion can be evaluated and managed effectively.[46] The Associations support this recommendation.

Effective (and code compliant) corrosion control systems should not be a basis for ineligibility. Linear anodes and a 100-millivolt shift are permitted under Part 192. The use of a 100-millivolt shift is not an indication of bad coating.[47] There could be other factors that support an operator's decision to use the 100-millivolt shift, such as soil resistivity or potential interference from parallel pipelines. Similarly, the presence of linear anodes is not indicative of poor external coating. Linear anodes can and are used to deal with challenging soil conditions, such as high resistivity or right-of-way conditions that restrict an operator's ability to install a traditional ground bed system. By denying eligibility to pipelines that use these kinds of systems, the Agency will unnecessarily

---

[41] 49 C.F.R. §§ 192.917(a);(e)(4) and 192.933.
[42] 49 C.FR. § 192.933.
[43] https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data; Gas Transmission and Gathering Incident Data – January 2010 – Present – onshore gas transmission, last downloaded on March 6, 2024.
[44] Proposed section 192.618(a)(4)(viii).
[45] *Id.*
[46] GPAC Voting Slides, at 7.
[47] *See* Peabody's Control of Pipeline Corrosion, 3rd edition (2018).

remove pipe segments that are receiving adequate cathodic protection. These segments should be treated similarly to segments that receive cathodic protection from traditional ground bed systems.

Removing pipe segments with tape coatings or shrink sleeves is also overly broad and arbitrary. Corrosion risks associated with tape coatings or shrink sleeves can be managed using the integrity management alternative, as evidenced by PHMSA's Advisory Bulletin covering protection of poorly coated pipe.[48] That guidance document instructed operators to conduct additional assessments, coordinate appropriate ILI technologies, and apply more stringent repair criteria, as necessary.[49]

Subpart O already requires operators to collect and integrate relevant data into their integrity management programs related to a covered segment. Information collected and integrated includes cathodic protection installed, coating type and condition, close interval survey results, and ILI results.[50] Identification of a corrosion threat will drive further assessment and remediation of that threat as required by Subpart O and proposed Section 192.618. Arbitrarily removing pipes with tape coatings and shrink sleeves will hinder the expansion of integrity management and drive unnecessary pipe replacements and pressure reductions. PHMSA should allow operators to use integrity-related data, such as ILI results, to determine the status of a pipe's coating and the magnitude of a possible corrosion threat.

D. PHMSA should not restrict eligibility for the integrity management alternative based on violations of Subpart O.

At the Meeting, certain GPAC members recommended disqualification from the integrity management alternative if an operator experiences a significant incident, following the effective date of the rule, and if PHMSA determines a violation of Subpart O occurred as a result of that incident.[51]

The Associations disagree with this recommendation for several reasons. First, this proposal was introduced for the first time during the GPAC meeting and represents a dramatic departure from the Class NPRM. Such a proposal should not be included in the Class Final Rule, particularly given the absence of prior notice and the opportunity for public comment.[52] Second, the Associations are not aware of any other provision in Part 192 that restricts an operator's ability to follow a regulation based on its prior enforcement history. Such a requirement raises a host of potential due process concerns. Subpart O contains dozens of requirements that implicate a wide range of conduct. A rule that treats any violation of Subpart O as a disqualifier for use of the integrity management alternative is overly broad. Nor is such a requirement even necessary given PHMSA's existing enforcement authority. PHMSA already has the power to impose appropriate remedial measures on operators who violate Subpart O as part of the enforcement process. The

48 Pipeline Safety: Ineffective Protection, Detection, and Mitigation of Corrosion Resulting from Insulated Coatings on Buried Pipelines, 81 Fed. Reg. 40,398, 30,300 (June 21, 2016).
49 *Id.*
50 49 C.F.R. § 192.917(b)(1).
51 GPAC Voting Slides, at 8.
52 The Administrative Procedure Act requires that an agency provide notice and the opportunity to comment to the public in a rulemaking proceeding.

Agency also has the ability to restrict companies from operating if such operation would be hazardous to life, property, or the environment.[53]

PHMSA does not bar operators from voluntarily using Subpart O now, even after an enforcement violation. PHMSA acknowledged during the Meeting that in twenty years, only 1% of enforcement cases involved special permit violations and the Agency has never issued an enforcement proceeding for violation of a class location special permit specifically.[54] PHMSA has a comprehensive enforcement program in place and an extensive history of ensuring compliance with the pipeline safety code. The Agency should use this process to address any violations of Subpart O and not prohibit future use of its regulations.

E. Operators should be able to use Subpart O to manage geohazard threats.

At the Meeting, some GPAC Members recommended that PHMSA should require operators to develop geohazard procedures. The GPAC members recommended that these procedures should address inspection tools, inspection intervals, patrols, employee and contractor training, finite element analysis, and girth weld repairs.[55] This approach is duplicative and unnecessary. PHMSA has already issued guidance to the industry on geohazard threats[56] and the Agency confirmed at the Meeting that it is considering a future geohazards rulemaking.[57] The Associations support this future rulemaking, and notes that industry is working in parallel on developing resources to help operators manage geohazard threats.[58]

While efforts to better understand and respond to geohazards continue to evolve, Subpart O already provides a rigorous and appropriate approach to manage geohazard threats. In accordance with section 192.917, operators must evaluate potential weather related and outside force damage, including consideration of seismicity, geology, and soil stability.[59] Identification of weather-related and outside force damage threats trigger the same integrity management requirements to assess, monitor, remediate, and adopt preventative and mitigative measures as any other integrity-related threat. In addition, PHMSA added a regulation in 2022 requiring operators to assess their pipelines 72 hours "after the point in time when the operator reasonably determines that the affected area can be safely accessed by personnel and equipment."[60] This ensures that operators

---

[53] *See* 49 C.F.R. § 190.233(a)("Corrective action may include suspended or restricted use of the facility, physical inspection, testing, repair, replacement, or other appropriate action.").
[54] GPAC Transcript, Mar. 27, 2024, at 34:4-6.
[55] GPAC Voting Slides, at 9.
[56] Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and other Geological Hazards, 87 Fed. Reg. 33,576 (June 2, 2022).
[57] GPAC Transcript (Mar. 29, 2024), https://primis-meetings.phmsa.dot.gov/meetings/f64a12c1-01fc-444d-9ffa-d0ea90bc314d/files/3ea9e12c-4e8d-4b3d-9d85-d471f55bda89/PHMSA_Day_5_Class_Location_Requirements_Transcript_03292024.pdf, at 76: 11-13.
[58] In November 2023, INGAA and the INGAA Foundation, published a "Framework for Geohazard Management" as part of its Integrity Management-Continuous Improvement (IMCI) 2.0 initiative. IMCI 2.0 2023 Framework for Geohazard Management (2023), https://ingaa.org/imci-2-0-2023-framework-for-geohazard-management/
API RP 1187, a new recommended practice that will instruct operators on how best to manage geohazards, was published on August 27, 2024.
[59] 49 C.F.R. § 192.917(a)(3).
[60] *Id.* § 192.613(c)(2).

will quickly evaluate the safety of the pipeline and determine if further actions are necessary to address a geohazard or other impacts to the pipeline.

F. Geohazards should not be used as an eligibility factor.

At the Meeting, some GPAC members recommended that until PHMSA has addressed geohazards in a rulemaking, a pipeline segment moving from Class 1 to Class 3 with a known geohazard within 600 feet of the segment should not be allowed to use the integrity management alternative.[61] The Associations do not support this recommendation. First, geohazards can be extremely unique, and the addition of blanket geohazard eligibility criteria in the Class Final Rule will unnecessarily exclude pipelines that can be safely managed under the integrity management alternative. The threat level of a geohazard can vary significantly. Second, as discussed above, the technical foundation for operators to address geohazards exists today. Third, the 600-foot distance is an arbitrary value and a geohazard located within 600 feet of the pipeline may not have any effect on the safety of the pipeline. Finally, it makes little sense to allow operators to manage geohazards within the integrity management program but prohibit operators from entering the program with a known geohazard. If an operator can manage a geohazard on a segment already in the program, then it should certainly be safe to allow an operator to enter the program with the same threat.

G. Certain grandfathered pipe should be eligible for the integrity management alternative.

At the Meeting, the GPAC members recommended that pipe segments that "have been operating in accordance with sections 192.619(c) & (d)" should be considered eligible for the integrity management alternative, if the operator has a 1.25 times MAOP pressure test.[62] The Associations agree with this recommendation. The Agency should allow pipe operating under Section 192.619(c) and (d) to be eligible for the integrity management alternative. Certain grandfathered pipe—in class 3, 4, and HCAs and piggable MCAs with a pressure test greater than or equal to 1.25x MAOP—can continue to be safely managed and should be eligible for the integrity management alternative.

H. PHMSA should permit operators to restore pressure on pipeline segments that previously underwent class location changes.

At the Meeting, GPAC members recommended that PHMSA allow a restoration of pressure to no more than the 0.72 design factor recognizing the requirement for a pressure test to 1.25 times MAOP.[63] The Associations agree with this recommendation. The Class Final Rule should provide that for pipeline segments that underwent pressure reductions due to class location changes prior to the availability of the integrity management alternative, operators may restore the previous pressure up to a 0.72 design factor, if the segments can meet the requirements of the integrity management alternative. Where an operator has reduced its MAOP due to a previous class location change, it would need to evaluate the engineering and operational history as part of Subpart K uprating requirements.

---

[61] GPAC Voting Slides, at 10.
[62] *Id.* at 11.
[63] *Id.* at 12.

PHMSA has allowed uprating of class location change segments through its special permit process.[64] Many pressure reductions that occurred due to a class location change were driven by the conservatism of the 1950-era class regulations and the delays in receiving a special permit. If the pipeline segment has a sufficient pressure test, there is not a risk-based or engineering reason to treat these segments differently than the lines that will undergo class changes after the integrity management alternative becomes available. In addition, this will align closely with the Part 195 regulations (49 C.F.R. § 195.106) where all pipe is designed with a 0.72 design factor.

Further, there are important reliability and capacity reasons to permit the restoration of pressure of these segments. As discussed at the Meeting, gas demand continues to grow at a strong rate, with an approximately 50 percent increase in the past ten years.[65] Gas transmission pipeline infrastructure development has not kept the same pace.[66] Allowing pipe segments to return to pressures under which they previously operated (up to 0.72 design factor) is a safe and efficient way to increase capacity without new construction, alleviating the environmental and landowner concerns that can accompany new gas infrastructure construction.[67]

I. PHMSA should revise the eligibility criteria related to certain seam types.

In the Class NPRM, PHMSA proposed to disqualify pipe segments with vintage seam types from the integrity management alternative.[68] Specifically, proposed section 192.618(a)(4)(vi) seeks to exclude pipelines that have low frequency electric resistance welded (LF-ERW), direct current welded (DCW), and electric flash welded (EFW) seam types. At the Meeting, GPAC members recommended that PHMSA consider alternatives to these proposed exclusions.[69] The Associations believe that LF-ERW, DCW, and EFW (collectively, selected vintage seam pipes) should be eligible for the integrity management alternative.

PHMSA did not provide a specific rationale in the Class NPRM or during GPAC discussions supporting this proposed exclusion. While the Agency has conducted research and shared learnings on selected vintage seam pipes,[70] PHMSA's incident data demonstrates that these types of pipes can be managed safely.

---

[64] *See* PHMSA-2018-0099 (allowing the operator to uprate the operating pressure previously decreased due to a class location change).

[65] GPAC Transcript, Mar. 27, 2024, at 130:2-9.

[66] *Id.* ("Over the last 10 years, gas demand has increased over 50 percent. Pipeline capacity has increased less than 25 percent. PJM estimates that by 2040, peak gas demand will increase—will more than double because gas is required to backstop wind and solar.").

[67] One GPAC member stated at the Meeting that "[i]f that's a way to then get out of having to build more pipeline on more new landowners, more environmental resources, that seems like a good play." GPAC Transcript, Mar. 29, 2024, at 271:4-7.

[68] *See* Proposed Section 192.618(a)(4)(vi).

[69] GPAC Voting Slides, at 13.

[70] *See* ALN-88-01 (January 28, 1988), previously available at https://www.phmsa.dot.gov/regulations/federal-register-documents; *See also*, ALN-89-01 (March 8, 1989), https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/legacy/interpretations/Interpretation%20Files/Pipeline/1989/PI89001.pdf; *See also,* PHMSA, Comprehensive Study to Understand Longitudinal Electric Resistance Welded (ERW) Seam Failures, https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=390

1. LF-ERW pipe

INGAA analyzed all of PHMSA's incident data for the past 15 years. There have been 1,531 reportable incidents on about 297,693 miles of onshore gas transmission pipelines during this period, of which 12 were attributable to LF-ERW pipe seams.[71] None of which were located in HCAs. INGAA surveyed its members and estimated the total LF-ERW gas transmission pipeline mileage to be 17,227.[72] If you apply the 12 incidents to the 17,227 figure, this equates to less than one incident per year. By comparison, there were 109 external corrosion and 90 internal corrosion incidents over the same 15-year period affecting all 297,693 onshore gas transmission miles.

The comparison with corrosion is important because there are long-established practices of managing external and internal corrosion that integrity management enhances. If you apply the same logic to selected vintage seam pipe, then an equal or greater level of safety will be achieved by the Class Final Rule. For instance, INGAA members can apply the integrity management provisions of 192.917(e)(4) to effectively manage these seam types.

2. DC-welded pipe

Another type of pipe that PHMSA excludes is DCW pipe. PHMSA places it in the same category as LF-ERW for incident reporting. This type of pipe was manufactured by a single manufacturer, Youngstown Steel & Tube in Youngstown, Ohio from 1930 to 1980.[73] PHMSA proposed making all pipe from this mill ineligible. This approach fails to recognize changes made at the facility to improve the quality of the pipe. The original mill that began operation in 1930 had a larger diameter mill for 16 to 26-inch pipe. The mill was expanded in 1935 to manufacture smaller diameter (six to 12-inch) pipe. The mill was replaced in 1948. The manufacturer improved the quality of the pipe by:

- trimming as-received skelp to width, edge beveling and shot blasting which resulted in improving the surfaces to be welded;
- flash-trimming the inside and outside seams to remove surface stress concentrators which resulted in removing potential flaws; and
- using a magnetic flux inspection of the seam after welding and again after hydrostatic testing to evaluate seam quality which resulted in identifying and removing additional flaws.

As a result of these improvements, pipe produced in the 1948 mill should be eligible under the Class Final Rule.

3. EFW pipe

---

[71] PHMSA's incident data categorizes LF-ERW and DCW pipe as LF-ERW pipe.
[72] *See* Attachment A for a detailed discussion of how this mileage total was calculated.
[73] Kiefner, J.F. and E.B. Clark, History of Line Pipe Manufacturing in North America, CRTD-Vol. 43, The American Society of Mechanical Engineers, 345 East 47th Street, New York, NY 10017, 1996, Table C-5, page C-18.

PHMSA also proposed to make flash welded pipe (EFW) ineligible for the class location rule. The flash welding process was used by a single manufacturer, AO Smith Corporation, a large manufacturer of EFW pipe starting in about 1927. AO Smith continued manufacturing EFW pipe until 1969.[74] PHMSA did not provide a specific rationale in the Class NPRM or during GPAC discussions supporting this proposed exclusion.

There is no technical support for this proposed exclusion. As demonstrated below, this type of pipe can be safely managed using integrity management. The Associations reviewed PHMSA's incident data which indicates that there were six incidents on flash-welded pipe over the past 15 years.

One incident was seam-related and five were related to cracking in hard spots in the pipe body.[75] The seam-related incident resulted in a leak on a weld-seam anomaly present from the original manufacturing. The incident report indicated that pipe had not been pressure tested at the time of original installation or subsequently. PHMSA proposed and the Associations agree that a pressure test to 1.25 x MAOP is required to be eligible under this rule.

The five other incidents were related to hard spots.[76] Hard spot threats have been proven to be safely managed by operators. Operators have known about the possibility of hard spots for some time and commissioned a report through the INGAA Foundation in 2004 to provide guidance to operators on how to manage this threat under integrity management.[77] The report highlighted AO Smith flash welded pipe as a predominant source of pipe with hard spots. A small number of other manufacturers were also identified. A hard spot alone is not a threat; however, it becomes a threat when acted upon by atomic hydrogen.[78] Hard spot ILI tools were developed and deployed in the 1990s and their use continued into the early 2000s. Operators used the ILI and managed hard spots largely preventing incidents as reflected in five (of 1,531) noted over the past 15 years.

An incident investigated by the NTSB in 2019 led INGAA, the INGAA Foundation, PRCI, and the broader pipeline industry to dedicate substantial resources to make advancements in hard spot management. The efforts include drafting a report that will be completed in the coming months that will show:

- an updated catalog of incidents including non-reportable events, such as small leaks and near-misses for particular pipe manufacturers and vintages;

---

[74] *Id.*

[75] https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data; Gas Transmission and Gathering Incident Data – January 2010 – Present – onshore gas transmission, last downloaded on March 6, 2024.

[76] Hard spots develop during hot rolling of a steel plate when an uncontrolled release of water locally cools a portion of the plate too quickly. The water-quenched areas form untempered martensite, with hardness levels locally much higher than the remainder of the pipe.

[77] Clark, E.B., B.N. Leis and R.J. Eiber, Integrity Characteristics of Vintage Pipelines, prepared for the INGAA Foundation, F-2002-50435, Battelle, Columbus, Ohio, 43201-2693, October 2004.

[78] *Id.* at 16.

- a reexamination of the susceptibility of hard spots to failure caused by cracking and sources of atomic hydrogen that can cause cracking; and
- an evaluation of the current state of in-line inspection technology and the application of response criteria to make repairs or cut out the pipe.

All of this work will further support the evidence that hard spots can be safely managed under the Class Final Rule.

4. Existing Code Requirements

The crack repair criteria in RIN-2 were not part of the regulations when the Class NPRM was published. These criteria, and especially the crack depth threshold of 50 percent will help conservatively identify cracks before they result in an incident. Section 192.917(e)(3)(i) provides an additional level of safety protection by requiring an integrity assessment if an incident occurs on selected vintage seam pipes.

Another integrity management provision that provides a higher level of safety assurance is section 192.917(e)(2), which requires an analysis of the potential for cyclic fatigue on affected pipe at least every seven years (not to exceed 90 months and in this instance growth of a seam anomaly by cyclic fatigue).

Both provisions listed above will result in operators safely managing threats found on selected vintage seam types where class location changes have occurred.

5. Summary

Subpart O Integrity Management provisions provide the most effective means of managing class changes. INGAA reviewed the experience of the last 15 years in HCAs as a measure of the actual safety performance of LF-ERW pipe. There have been no incidents on LF-ERW related to seams in HCAs over the past 15 years.[79] This is a clear indication that operators have effectively applied the provisions of integrity management with selected vintage seam pipes. This incident data demonstrates that the concerns with LF-ERW in the 1988 and 1989 Advisory Bulletins and the research studies conducted by PHMSA in 2013 can be addressed by integrity management provisions.

Subpart O already provides for the management of threats related to selected vintage seam pipe types,[80] and these pipes have been effectively managed in high consequence areas. In accordance with section 192.917, operators are required to identify the threats to their pipeline and use assessment methods to evaluate for applicable seam type threats. In fact, PHMSA has allowed an operator to apply integrity management principles to LF-ERW pipe as part of a class location special permit.[81] The key integrity risk for these seam types relate to manufacturing issues, but eligibility for the integrity management alternative requires a pressure test to at least 1.25 x MAOP.

---

[79] https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data; Gas Transmission and Gathering Incident Data – January 2010 – Present – onshore gas transmission, last downloaded on March 6, 2024.
[80] *See, e.g.*, 49 C.F.R. § 192.917(b)(1) &(e)(4).
[81] *See* PHMSA-2008-0158.

Selected vintage seam types tested to 1.25 x MAOP have demonstrated sufficient strength and successfully mitigated manufacturing risks. These lines can be effectively managed pursuant to Subpart O, rather than replaced. PHMSA has not demonstrated why a different approach should be adopted for a pipe segment undergoing a class change. Further, implementing an exclusion of pipe segments with selected vintage seam types from the integrity management alternative will result in unnecessary pressure reductions or pipe replacement projects. These projects would result in increased emissions and would not necessarily improve pipeline safety.

J. PHMSA should revise its proposal to exclude pipeline segments without an eight-hour pressure test.

In the Class NPRM, PHMSA proposes to disqualify pipeline segments lacking an eight-hour Subpart J pressure test at a minimum test pressure of 1.25 times MAOP.[82] The Associations encourage PHMSA to revise this proposal to accommodate situations where an eight-hour test is not currently required. For instance, under section 192.505(d), fabricated units and short sections of pipe may be tested for four hours[83] and pre-code pipe not previously subject to Subpart J during construction may operate using the original pressure test.

IV. Technical Application – Assessments and Remediation

A. PHMSA should allow operators to follow the repair criteria and remediation timeframes in Subpart O.

In the Class NPRM, PHMSA proposed different assessment and repair criteria separate from those applied to high consequence areas.[84] At the Meeting, the GPAC members discussed this proposal and recommended that PHMSA use the same assessment and repair criteria currently in place for high consequence areas.[85] The differences between Section 192.618 and Subpart O are attributable to the concurrent rulemaking of the Class NPRM and revisions to Subpart O made in RIN-2.[86] The RIN-2 amendments were developed through an extensive rulemaking process that updated the risk-based methodologies which underlie integrity management. Conversely, the proposed criteria in the Class NPRM appear arbitrary, would drive unnecessary projects, and hinder effective resource deployment. Utilizing the Subpart O repair criteria ensures that operators are repairing the highest risk pipe at the earliest time versus the use of an arbitrary repair timeline that would require an operator to repair a lower risk pipe earlier than pipe at a greater risk. Further, repair criteria and remediation timeframes that work effectively in high consequence areas should also be suitable in class change locations, and there is no clear reason why operators would need a separate integrity management program for these pipeline segments.

[82] Proposed section 192.618(a)(4)(v).
[83] *See* 49 C.F.R. § 192.505(d).
[84] Proposed section 192.618(b).
[85] GPAC Voting Slides, at 14; *See also*, GPAC Transcript, Mar. 28, 2024, at 229: 16-19.
[86] Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments, 87 Fed. Reg. 52,224 (Aug. 24, 2022).

B. PHMSA should permit operators to use previous assessments conducted prior to a class location change.

In the Class NPRM, PHMSA proposed that operators must conduct an initial assessment within 24 months of the Class 1 to Class 3 location segment change.[87] At the Meeting, the GPAC members recommended that PHMSA allow the use of previous assessments in lieu of an initial assessment so long as the remediation is completed and the reassessment interval is maintained.[88] PHMSA has not asserted a technical basis for invalidating an assessment conducted prior to the class change. Requiring operators to conduct a new assessment within 24 months of a class change instead of permitting the use of a previous assessment, potentially completed right before the class change occurred, is arbitrary and will result in the deployment of unnecessary resources.[89]

The Associations support the principle that only assessments that can provide meaningful data will be used as part of an integrity management plan, but it appears that PHMSA has simply pulled the 24-month timeframe from the existing requirement in Section 192.611(d). Modern technology permits operators to predict developments over time periods that far exceed 24 months.[90] Various assessments conducted by operators, including ILI tools that address specific threats, geohazard assessments, leak surveys, and corrosion control surveys, all provide good data that is actionable for years and therefore operators should be allowed to use these assessments, even if they predate the class location, to satisfy this requirement. These assessments are valid and provide high-quality data for periods far exceeding 24 months.

C. Operators should remain eligible for the integrity management alternative if cracking is discovered in a class change location area or within 5 miles of the class 1 to 3 segment.

In the Class NPRM, PHMSA proposed to exclude pipe segments from the integrity management alternative if the segment had "cracking in the pipe body, seam, or girth welds in or within 5 miles of the Class 1 to Class 3 location segment that is over 20 percent of the pipe wall thickness, has a predicted failure pressure less than 100 percent of SMYS, has a predicted failure pressure less than 1.50 times MAOP, has experienced a leak or a rupture due to pipe cracking, or for which analysis …indicates the pipe could fail in brittle mode."[91] At the Meeting, the GPAC members recommended that PHMSA allow the continued use of section 192.618 if cracking is discovered in the Class 1 to 3 segment or within 5 miles surrounding the segment after an operator implements Subpart O.[92]

The Associations support the GPAC recommendation. As discussed above, Subpart O provides an effective method for managing crack threats and should be used as part of the integrity management alternative. PHMSA's proposal to remove segments from the program where

---

[87] *See* Proposed section 192.618(b)(2).
[88] GPAC Voting Slides, at 15.
[89] As discussed at the Meeting, it would not be effective to go back and re-run a tool an operator had just conducted the previous year because of a subsequent class change. GPAC Transcript, Mar. 28, 2024, at 170:15:25 and 171:1-17.
[90] *Id.* at 171:13-17.
[91] Proposed section 192.618(a)(4)(vii).
[92] GPAC Voting Slides, at 16.

cracking is discovered within five miles is arbitrary. The five-mile upstream and downstream cutoff appears to be a vestige from the special permit process without a clear technical basis.[93] A blunt, five-mile upstream/downstream cutoff has clear flaws. Primarily, pipe at or within five miles of the class 1 to 3 segment may not share the same characteristics or materials as the segment within the class 1 to 3 segment. Pipe segments may have different soil conditions, manufacturers, seam types, and external loads, completely undercutting the purpose of the five-mile buffer. Since cracking threats can be effectively managed through Subpart O, the Agency should permit operators to expand their integrity management programs and improve pipeline safety.

D. PHMSA should revise certain preventive and mitigative measures and valve requirements.

The Associations generally support the GPAC recommendations related to preventive and mitigative (P&M) measures and valve requirements.[94] Many of the P&M measures proposed under section 192.618(f) are already in place for special permits and used on HCA segments in accordance with section 192.935(a). However, the Associations point out that the P&M measures required in Subpart O already provide sufficient monitoring and risk reduction for pipeline safety. Adding requirements beyond what is necessary in Subpart O will likely be burdensome with no commensurate benefit.

At the Meeting, the GPAC members spent considerable time discussing requirements related to shorted casings.[95] Under proposed Section 192.618(f)(8), operators would need to clear shorted casings, a requirement that goes beyond what is currently required in Part 192.[96] Sometimes it is impractical to remove a shorted casing and the threat can be managed using other integrity management tools, such as ILI. PHMSA should remove the requirement to clear a shorted casing or provide a mechanism where operators can demonstrate that the risk can be managed.

PHMSA should also revise the proposed requirement in section 192.618(f)(5) to allow operators the option to install concrete pads over pipe with depth of cover less than 24 inches, among other mitigative measures, similar to the protections allowed in section 192.327(c). This would increase an operator's flexibility to manage shallow depth of cover without the loss of any safety benefit.

E. PHMSA should not require validation of ILI results in accordance with API RP 1163, Level 3.

Proposed section 192.618(b)(4) requires a heightened level of validation that is not necessary for safety. The Associations support the use of API RP 1163 to validate ILI results but notes that operators primarily use Levels 1 and 2, which provide technically sound methods to validate tool performance with a high degree of confidence. Level 3 is often used by ILI vendors attempting to establish tool performance specifications, but is not as useful for pipeline operators. Level 3 requires extensive measurements and can be impractical on segments that have not undergone many ILI assessments or contain few anomalies. Subpart O does not currently require operators

[93] GPAC Transcript, at 284: 17-19 (Mar. 28, 2024).
[94] GPAC Voting Slides, at 17.
[95] GPAC Transcript, Mar. 28, 2024, at 262:2-21.
[96] *Id.*, at 261: 15-20.

to validate ILI results in accordance with Level 3, and there is no reason to depart from these practices for the purposes of class location change segments.[97]

V. Conclusion

The Associations support PHMSA's efforts to complete this rulemaking. Considering an integrity management alternative to class location change requirements presents the most impactful regulatory advancement the Agency could make to modernize the regulations. Such an alternative would incorporate modern technologies and risk-based management systems, significantly reduce methane emissions, and allow operators to use resources efficiently. The Associations have compiled their recommended redlines to the regulatory text as Attachment B. The Associations appreciate PHMSA's consideration of these comments and look forward to continued discussion on this topic.

[97] *See also* Joint Trade Association Comments, Docket No. PHMSA-2017-0151, at 21.

Respectfully submitted,

Ben Kochman
Director of Pipeline Safety Policy
Interstate Natural Gas Association of America
25 Massachusetts Ave NW, Suite 500N
Washington, D.C. 20001
bkochman@ingaa.org

Erin Kurilla
Vice President, Operations and Safety
American Public Gas Association
201 Massachusetts Ave NE, Suite C-4
Washington DC 20002
ekurilla@apga.org

Alan M. Chichester
Senior Director
Safety, Operations, & Engineering
American Gas Association
400 North Capitol Street, NW
Washington, D.C. 20001
achichester@aga.org

Dave Murk
Senior Director, Pipelines
Midstream and Industry Operations
American Petroleum Institute
200 Massachusetts Avenue, N.W.
Suite 1100
Washington, D.C. 20001
murkd@api.org

Andrew Mooney
Director, Government Affairs
GPA Midstream Association
505 9th Street, N.W., Suite 602
Washington, D.C. 20004
Amooney@gpamidstream.org

<u>Attachment A-Calculations</u>

Computing incident rates, *i.e.*, the number of incidents normalized by applicable mileage expressed typically as incidents per mile per year.

- Since PHMSA does not collect seam-type mileage data in the annual report, INGAA surveyed its members to confirm the amount of LF-ERW pipe in their systems.

- INGAA's members represent about two-thirds of the overall gas transmission mileage. INGAA members returned surveys that accounted for 206,426 miles of the 297,693 reported by all operators in 2023 annual reports (approximately 70% of the total mileage). INGAA members reported 11,980 miles of LF-ERW pipe.

- INGAA then estimated the total amount of LF-ERW pipe by conservatively assuming that the amount of LF-ERW pipe in the industry is proportional to that of INGAA's members, or equivalent to a total of approximately 17,277 miles. The assumption of proportionality is likely conservative as non-INGAA members generally have smaller diameter pipes that are predominantly seamless or ERW.

- Using the 12 incidents that occurred in the past 15 years with the estimated mileage of LF-ERW pipe (17,277 miles) yields an incident rate of 4.63 incidents per 100,000 miles per year. INGAA used 100,000 miles per year because there are only 17,227 miles of LF-ERW pipe out of a total of approximately 297,693 miles of onshore gas transmission pipelines. This places the incidents on an equivalent scale.

- To make an accurate comparison between LF-ERW incidents and other common causes of incidents, INGAA pulled the incident rate for external and internal corrosion and applied that to the 100,000 miles per year threshold. This calculation yielded a 2.44 and 2.02 rate for external and internal corrosion, respectively for the same 15 years.

Attachment B--Proposed Regulatory Text

While the Associations have developed these comments in direct response to the discussion at the Meeting, given the extensive modifications of Part 192 since the Class NPRM was first introduced, the Associations are also providing consolidated revisions to the regulatory text for the Agency's review. The text in the black represents either existing code language or the regulatory text proposed in the Class NPRM (with the exception of § 192.712). The red text signifies proposed modifications from the Associations.

§ 191.22 National Registry of Operators.

*** * * * ***

(c) * * *

(2) * * *

~~(vi) A change in the classification of a pipeline segment from a Class 1 to a Class 3 location or a Class 2 to a Class 3 where the operator chooses to confirm or revise the maximum allowable operating pressure (MAOP) in accordance with § 192.611(a)(4) of this chapter. The notification must include the following information about the Class 1 to Class 3 or a Class 2 to a Class 3 location segment: State, county, pipeline name or number, pipe diameter, MAOP, wall thickness, pipe grade/strength, seam type, Class 1 to Class 3 or a Class 2 to a Class 3 location change date, segment length, pipeline location by both GIS GPS coordinates and pipeline system survey stations or mile posts for the starting and ending points of the Class 1 to Class 3 location change segment, and the date of the Class 1 to Class 3 location change.~~

*** * * * ***

§ 192.3 Definitions

* * * * *

Class 1 to Class 3 ***or Class 2 to Class 3*** *location segment* means a pipeline segment where:

(1) The segment has changed from a Class 1 to a Class 3 location **or a Class 2 to a Class 3**; and

(2) The operator is confirming or revising the maximum allowable operating pressure per § 192.611(a)(4). At the operator's discretion, the endpoints of the Class 1 to Class 3 **or Class 2 to Class 3** location segment may extend further than the beginning and endpoints of the Class 3 location involved.

* * * * *

In-line inspection segment means all pipe within a Class 1 to Class 3 **or a Class 2 to Class 3** location segment and all pipe adjacent to the Class 1 to Class 3 **or Class 2 to Class 3** location segment between the nearest upstream in-line inspection launcher and the nearest downstream in-line inspection receiver.

* * * * *

Predicted failure pressure means the calculated pipeline anomaly failure pressure, based on the use of an appropriate engineering evaluation method for the type of anomaly being assessed, that does not have an included safety factor. Different anomaly types (*e.g.*, dent, crack, or metal loss) will require different engineering assessment or analysis methods to determine the predicted failure pressure.

* * * * *

§ 192.7 What documents are incorporated by reference partly or wholly in this part?

* * * * *

(b) * * *

(12) API STANDARD 1163, ''In-Line Inspection Systems Qualification,'' Second edition, April 2013, Reaffirmed August 2018, (API STD 1163), IBR approved for §§ 192.493, **and** 192.618(b)(4)~~**, and (b)(4)(iii).**~~

* * * * *

(c) * * *

(6) ASME~~**/ANSI**~~ B31.8S~~-~~**2004 2018,** ~~**''Supplement to B31.8 on Managing System Integrity of Gas Pipelines,'' 2004, (ASME/ANSI B31.8S–2004)**~~ **ASME B31.8S-2018, Managing System Integrity of Gas Pipelines, Issued November 28, 2018 (ASME B31.8S)** IBR approved for **§§ 192.13(d); 192.714(c) and (d)**; §§ 192.618; 192.903 note to *Potential impact radius*; 192.907 introductory text, **and** (b); 192.911 introductory text, (i), **and** (k)~~**, (*l*),**~~ **through** (m); 192.913(a)~~**, (b),**~~ **through** (c); 192.917 (a), ~~**(b), (c), (d),**~~ **through** (e); 192.921(a); 192.923(b); 192.925(b); ~~**192.927(b), (c); 192.929(b)**~~; 192.933(c), **(d);** 192.935 ~~**(a)**~~, (b); 192.937(c); 192.939(a); and 192.945(a).

Note: While the Class NPRM did not cover the incorporation of ASME B31.8S (2018) by reference for the purposes of sections 192.714(d)(1) and 192.933(d)(1) and (d)(2)(iv), the Associations note that INGAA filed a petition for reconsideration on May 29, 2024, seeking the incorporation of the 2018 edition for these particular code sections. That petition for reconsideration is currently pending. The Associations also note that crack criteria within the 2018 edition (see Table A-4. 4-1 SCC Crack Severity Criteria) was discussed by the GPAC at the Meeting.

§ 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.

(b) ***Documentation of material properties and attributes.*** Records established under this section documenting physical pipeline characteristics and attributes, including diameter, wall thickness, seam type, and grade (*e.g.*, yield strength, **~~ultimate tensile strength~~**, or pressure rating for valves and flanges, etc.), must be maintained for the life of the pipeline and be traceable, verifiable, and complete. Charpy v-notch toughness values established under this section needed to meet the requirements of the ECA method at § 192.624(c)(3) or the fracture mechanics requirements at § 192.712 must be maintained for the life of the pipeline.

* * * * *

§ 192.611 Change in class location:

Confirmation or revision of maximum allowable operating pressure.

(a) * * *

(4) A Class 1 to Class 3 **or Class 2 to Class 3** location segment may have its maximum allowable operating pressure confirmed or revised in accordance with § 192.618.

* * * * *

(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 months of the change in class location. Pressure reduction under paragraph (a)(1) or (2) of this section within the 24-month period does not preclude establishing a maximum allowable operating pressure under paragraph (a)(3) of this section or implementing an integrity assessment program that meets paragraph (a)(4) of this section at a later date. The activities required in paragraphs (a)(3) or (4) of this section must be implemented prior to any future increases of maximum allowable operating pressure to meet paragraphs (a)(1) or (2) of this section.

§ 192.618 Class 1 to Class 3 or Class 2 to Class 3 location segment requirements.

A Class 1 to Class 3 **or Class 2 to Class 3** location segment must meet the following requirements:

(a) *Program requirements for a Class 1 to Class 3* ***or a Class 2 to Class 3*** *location segment.* For segments that change from a Class 1 to a Class 3 location **or a Class 2 to Class 3**, the maximum allowable operating pressure (MAOP) must be confirmed or revised by designating the segment involved as a high consequence area, as defined in § 192.903, and including it in an integrity management program in accordance with subpart O of this part, if the following criteria are met:

(1) *Timing of Class 1 to Class 3* ***or Class 2 to Class 3*** *location change.* **~~The Class 1 to Class 3 location segment change must have occurred after [INSERT EFFECTIVE DATE OF FINAL RULE]~~**. An operator must conduct a class location study **in accordance with § 192.609** on the in-line inspection segment at least once each calendar year, with intervals not to exceed 15 months**~~, in accordance with § 192.609~~**. An operator must maintain its in-line inspection segment change in class location study records in accordance with paragraph (h) of this section.

(2) *In-line inspection.* The in-line inspection segment must be assessed using instrumented in-line inspection tools that meet the requirements of paragraph (b)(1) of this section.

(3) *Hoop stress of Class 1 to Class 3* ***or Class 2 to Class 3*** *location segment.* The hoop stress corresponding to the MAOP of the Class 1 to Class 3 **or Class 2 to Class 3** location segment must not exceed 72 percent of SMYS in Class 3 locations.

(4) *Pipe attributes for review.* Pipeline segments with any of the following attributes cannot be a Class 1 to Class 3 **or a Class 2 to Class 3** location segment:

(i) Bare pipe;

(ii) Pipe ~~with wrinkle bends~~ **in the vicinity of a geohazard which could cause critical strain levels to be exceeded on an existing wrinkle bend**;

(iii) Pipe that does not have traceable, verifiable, and complete pipe material records for diameter, wall thickness, grade, seam type, **and** yield strength, **(unless the segment has material properties verified in accordance with § 192.607 within 24 months after the Class 1 to Class 3 or Class 2 to Class 3 location segment class location change)** ~~and tensile strength~~;

~~**(iv) Pipe that is uprated in accordance with subpart K (unless the segment passes a subpart J pressure test for a minimum of 8 hours at a minimum pressure of 1.39 times MAOP within 24 months after the Class 1 to Class 3 location segment change and prior to uprating or increasing the current MAOP);**~~

(**i**v) Pipe that has not been pressure tested ~~in accordance with subpart J for 8 hours at~~ **to at least** a minimum test pressure of 1.25 times MAOP (unless the segment passes a subpart J pressure test for a minimum of 8 hours at a minimum pressure of 1.25 times MAOP within 24 months after the Class 1 to Class 3 **or Class 2 to Class 3** location segment change)**, except for pipe compliant with §192.505(d)**;

(v~~i~~) Pipe with ~~direct current (DC), low frequency electric resistance welded (LF ERW), electric flash welded (EFW), or~~ lap-welded seams~~,~~ or pipe with a longitudinal joint factor below 1.0; ~~or~~

~~**(vii) Pipe with cracking in the pipe body, seam, or girth welds in or within 5 miles of the Class 1 to Class 3 location segment that is over 20 percent of the pipe wall thickness, has a predicted failure pressure less than 100 percent of SMYS, has a predicted failure pressure less than 1.50 times MAOP, has experienced a leak or a rupture due to pipe cracking, or for which analysis in accordance with paragraph (e) of this section indicates the pipe could fail in brittle mode.**~~

~~**(viii) Poor pipe external coating that requires a minimum negative cathodic polarization voltage shift of 100 millivolts or linear anodes along the Class 1 to Class 3 location segment to maintain cathodic protection in accordance with § 192.463, or a Class 1 to Class 3 location segment with tape wraps or shrink sleeves.**~~

~~**(ix) Pipe that transports gas whose composition quality is not suitable for sale to gas distribution customers, including, but not limited to, pipe with free-flowing water or hydrocarbons, water vapor content exceeding acceptable limits for gas distribution customer delivery, hydrogen sulfide (H2S) greater than one grain per 100 cubic feet, or carbon dioxide (CO2) greater than 3 percent by volume.**~~

~~**(x) Pipelines operating in accordance with § 192.619(c) or (d).**~~

~~**(xi) A Class 1 to Class 3 location segment, in-line inspection segment, or portion of it that has been previously denied by the special permit process in § 190.341.**~~

(b) *Pipeline integrity assessments.* In addition to the requirements specified in subpart O of this part, pipeline integrity assessments for the in-line inspection segment, including the Class 1 to Class 3 **or Class 2 to Class 3** location segment, must meet the following:

(1) *Assessment method.* Operators must perform pipeline assessments **in accordance with § 192.921(a)(1)** ~~**using the following in-line inspection tools or alternative methods as applicable for the pipeline integrity threats being assessed:**~~

~~**(i) In-line inspection with a high resolution magnetic flux leakage (HR - MFL) tool or an equivalent internal inspection device;**~~

~~**(ii) In-line inspection with a high resolution deformation tool (HR Deformation), with sensors and extension arms outside the tool cups, or an equivalent internal inspection device;**~~

~~**(iii) In-line inspection with an electromagnetic acoustic transducer (EMAT) tool or an equivalent internal inspection device;**~~

~~**(iv) In-line inspection with an inertial measurement unit (IMU) tool or an equivalent internal inspection device;**~~

(**i**~~**v**~~) An operator may use alternative methods **for the Class 1 to Class 3 or Class 2 to Class 3 location segment**, such as pressure testing or other technology (excluding direct assessment), upon submitting a notification to PHMSA 90 days prior to using the alternative method, in accordance with § 192.18.

(~~**v**~~**ii**) If an operator chooses not to conduct the in-line inspection ~~**as required in paragraphs (iii) or (iv)**~~ on a pipeline segment with a history of pipe body or weld cracking or pipe movement, then the operator must notify PHMSA in accordance with § 192.18.

(2) *Initial assessment.* Within 24 months of the Class 1 to Class 3 location **or Class 2 to Class 3** segment change, an operator must identify and document each integrity threat to which the pipeline segment is susceptible and conduct initial pipeline integrity assessments of the entire inline inspection segment for each threat in accordance with §§ 192.917, 192.921, and paragraph (b)(1) of this section, **unless the applicable threat assessments were completed within the assessment interval specified in §192.939(a)**.

(3) *Reassessments.* The operator must conduct periodic reassessments in accordance with § 192.937 and paragraph (b)(1) of this section at least once every 7 calendar years, with intervals not to exceed 90 months, as specified in § 192.939(a).

(4) *In-line Inspection Validation.*

Operators must validate the results of all in-line inspections, for each type in-line inspection tool run conducted in accordance with **§ 192.937(c)(1)** ~~**this section, to Level 3 standards in accordance with API Standard 1163 (incorporated by reference, *see* § 192.7)**~~.

~~**(i) An operator must analyze and account for uncertainties in reported results (*e.g.*, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) when identifying and characterizing anomalies**~~.

~~**(ii) For each threat type assessed by ILI tool type, an operator must validate the in-line inspection tool tolerance for each in-line inspection tool run using a minimum of 4 anomaly validations or 100 percent of anomalies, whichever is from past excavations in the in-line inspection segment, with documented anomaly dimensions (width, depth, length, and location) or other known pipe features that are appropriate for the in-line inspection tool.**~~

~~**(iii) For pipeline areas of metal loss where in-line inspection tool data for anomaly size and characterization are used in the determination of the predicted anomaly failure pressure, an operator must use Section 6.2.3, Table 1 – Characterizing Metal Loss Probabilities of Detection – Depth Detection Threshold, in accordance with API Standard 1163 (incorporated by reference, *see* § 192.7). Using the qualifiers and limitation criteria in Section 6.2.3, Table 1 of API Standard 1163 or technically proven criteria appropriate for the location, size, and type of the anomaly, an operator must evaluate the anomaly based on whether it is an extended metal loss, pit, or groove.**~~

(i~~**v**~~) An operator may use alternative methods for in-line inspection tool verification, such as calibration joints near the upstream and downstream ILI tool launchers and receivers, upon submitting a notification to PHMSA 90 days prior to using the alternative method, in accordance with § 192.18.

(5) ***Pipeline repairs*. Pipeline repairs must be completed in accordance with §192.933. Class 1 or Class 2 pipe within the Class 3 location must meet 1.39 times the MAOP failure pressure ratio requirements as applicable.** ~~***Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under § 192.933 and paragraphs (c), (d), and (e) of this section. An operator must promptly, but no later than 180 days after conducting a pipeline integrity assessment, obtain sufficient information about a condition to make such a determination of an integrity threat that requires remediation.**~~

~~(c) *Remediation schedule (In-line inspection segment).* In addition to the requirements specified in subpart O of this part, remediation for the in-line inspection segment, including the Class 1 to Class 3 location segment, must meet the following:~~

~~(1) *Immediate repair conditions.* An operator must repair the following conditions immediately upon discovery:~~

~~(i) Metal loss anomalies where the calculation of the remaining strength of the pipe shows a predicted failure pressure determined in accordance with § 192.712(b) less than or equal to 1.1 times the MAOP at the location of the anomaly.~~

~~(ii) Metal loss greater than 80 percent of nominal wall, regardless of dimensions.~~

~~(iii) Metal loss preferentially affecting a detected longitudinal seam and where the predicted failure pressure determined in accordance with § 192.712(d) is less than or equal to 1.25 times the MAOP.~~

~~(iv) A dent located between the 8 o'clock and 4 o'clock positions (upper 2⁄3 of the pipe) that has metal loss, cracking, or a stress riser, unless a technically proven engineering analysis conducted in accordance with § 192.712(c) demonstrates that critical strain levels will not be exceeded before the next engineering analysis or assessment is conducted.~~

~~(v) A crack or crack-like anomaly meeting any of the following criteria:~~

~~(A) Crack depth plus any metal loss is greater than 50 percent of pipe wall thickness;~~

~~(B) Crack depth plus any metal loss is greater than the inspection tool's~~

~~maximum measurable depth; or~~

~~(C) The crack or crack-like anomaly has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.25 times the MAOP.~~

~~(vi) An indication or anomaly that, in the judgment of the person designated by the operator to evaluate the~~

~~assessment results, requires immediate action.~~

~~(2) *One-year conditions.* An operator must repair the following conditions within 1 year of discovery:~~

~~(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2⁄3 of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless an engineering analysis conducted in accordance with § 192.712(c) demonstrates that critical strain levels will not be exceeded before the next engineering analysis or assessment is conducted.~~

~~(ii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld~~

~~**or at a longitudinal or helical (spiral) seam weld, unless an engineering analysis conducted in accordance with § 192.712(c) demonstrates that critical strain levels will not be exceeded before the next engineering analysis or assessment is conducted.**~~

~~**(iii) A dent located between the 4 o'clock and 8 o'clock positions (lower 1⁄3 of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis conducted in accordance with § 192.712(c) demonstrates that critical strain levels will not be exceeded before the next engineering analysis or assessment is conducted.**~~

~~**(iv) Metal loss anomalies where a calculation of the remaining strength of the pipe shows a predicted failure pressure, determined in accordance with § 192.712(b), at the location of the anomaly less than or equal to 1.39 times the MAOP for Class 2 locations, and 1.50 times the MAOP for Class 3 and 4 locations. For metal loss anomalies in Class 1 locations outside the Class 1 to Class 3 location segment with a predicted failure pressure greater than 1.1 times MAOP, an operator must follow the remediation schedule specified in ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 7, figure 4. For Class 1 pipe within the Class 1 to Class 3 location segment, a metal loss anomaly with a predicted failure pressure of less than or equal to 1.39 times the MAOP.**~~

~~**(v) Metal loss that is located at a crossing of another pipeline, is in an area with widespread circumferential corrosion, or could affect a girth weld, with a predicted failure pressure determined in accordance with § 192.712(b) less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and all Class 3 and Class 4 locations. For Class 1 pipe within the Class 1 to Class 3 location segment, metal loss with a predicted failure pressure of less than or equal to 1.39 times the MAOP.**~~

~~**(vi) Metal loss preferentially affecting a detected longitudinal seam 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, or 1.50 times the MAOP for all other Class 2 locations and all Class 3 and Class 4 locations. For Class 1 pipe within the Class 1 to Class 3 location segment, metal loss with a predicted failure pressure of less than or equal to 1.39 times the MAOP.**~~

~~**(vii) A crack or crack-like anomaly that has a predicted failure pressure determined in accordance with § 192.712(d) that is less than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and all Class 3 and Class 4 locations. For Class 1 pipe within the Class 1 to Class 3 location segment, a crack or crack-like anomaly with a predicted failure pressure of less than or equal to 1.39 times the MAOP.**~~

~~**(3) *Remediation schedule (Class 1 to Class 3 location segment).* In addition to the requirements in paragraph (e) of this section, remediation for the Class 1 to Class 3 location segment must meet the following:**~~

~~**(i)** ***One-year condition.*** **An operator must repair the following conditions within 1 year of discovery: (A) Pipe wall thickness loss greater than 40 percent.**~~

~~**(B) A crack with depth greater than 40 percent of the pipe wall thickness.**~~

~~**(ii) [Reserved].**~~

~~**(4)** ***Two-year condition for crack repairs (in-line inspection segment).*** **An operator must repair the following condition within 2 years of discovery:**~~

~~**(i) A crack or crack-like anomaly that has a predicted failure pressure determined in accordance with § 192.712(d) that is greater than or equal to 1.39 times MAOP, and the crack depth is greater than or equal to 40 percent of the pipe wall thickness.**~~

~~**(ii) [Reserved].**~~

~~**(5)** ***Monitored condition.*** **An operator does not have to schedule the following conditions for remediation but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation. Monitored conditions are the least severe and will not require examination and evaluation until the next scheduled integrity assessment interval, provided an analysis shows they are not expected to grow to dimensions meeting a 1-year condition prior to the next scheduled assessment. Monitored conditions are:**~~

~~**(i) A dent with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position**~~

~~**and the 8 o'clock position (bottom 1⁄3 of the pipe);**~~

~~**(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2⁄3 of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), and an engineering analysis conducted in accordance with § 192.712(c) demonstrate that critical strain levels on the dent will not be exceeded;**~~

~~**(iii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or longitudinal or helical (spiral) seam weld, and an engineering analysis conducted in accordance with § 192.712(c) demonstrates that critical strain levels on the dent and girth or seam weld will not be exceeded;**~~

~~**(iv) A dent that has metal loss, cracking, or a stress riser, and an engineering analysis conducted in accordance with § 192.712(c) demonstrates that critical strain levels will not be exceeded;**~~

~~**(v) Metal loss preferentially affecting a detected longitudinal seam and where the predicted failure pressure determined in accordance with § 192.712(d) is greater than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, or 1.50 times**~~

~~the MAOP for all other Class 2 locations and all Class 3 and Class 4 locations. For Class 1 pipe within the Class 1 to Class 3 location segment, metal loss with a predicted failure pressure of less than or equal to 1.39 times the MAOP; and~~

~~(vi) A crack or crack-like anomaly for which the predicted failure pressure, determined in accordance with § 192.712(d), is greater than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe, or 1.50 times the MAOP for all other Class 2 locations and all Class 3 and Class 4 locations. For Class 1 pipe within the Class 1 to Class 3 location segment, a crack or crack-like anomaly with a predicted failure pressure greater than 1.39 times the MAOP.~~

~~(d) *Special requirements for crack anomalies.* If cracks are discovered in the Class 1 to Class 3 location segment that meet the criteria in paragraph (a)(4)(vii) of this section, the operator must implement the requirements in § 192.611(a)(1), (2), or (3) within 2 years. Until the pipe is replaced, operators must remediate cracks as specified in paragraph (c) of this section.~~

~~(e) *Pipe and weld cracking inspections.* Except for pipe coated with fusion-bonded or liquid-applied epoxy coatings and excavations performed in accordance with § 192.614(c), an operator must inspect any pipe in the in-line inspection segment, including the Class 1 to Class 3 location segment, that is uncovered for any reason to evaluate the pipe for cracking where the coating is removed. An operator must use non-destructive examination methods and procedures appropriate for the type of non-destructive examination method, and for the type of pipe and integrity threat conditions in the ditch. If an operator finds any cracking, the operator must conduct an analysis in accordance with § 192.712 and remediate anomalies in accordance with paragraphs (c) and (d) of this section.~~

(f) *Additional preventive and mitigative measures.* **Apply preventative and mitigative measures in accordance with 192.935. For an electrolytic casing short, operators must remove the electrolyte from the casing/pipe annular space no later than 1 calendar year after the short is identified or monitor the casing for corrosion growth through ILI inspection. Operators must clear the metallic short no later than 1 calendar year after the short is identified or monitor the casing for corrosion growth through ILI inspection~~.~~**

~~For a Class 1 to Class 3 location segment, an operator must conduct the following operations and maintenance actions and surveys within 2 years of the Class 1 to Class 3 location segment change, evaluate the findings, and remediate as follows:~~

~~(1) Close interval surveys with an ''on and off'' current at a maximum 5-foot spacing. An operator must evaluate in accordance with § 192.463 and remediate the unprotected pipe segments within 1 year of the survey. Operators must conduct close interval surveys on reassessment intervals of at least once every 7 calendar years, with intervals not to exceed 90 months.~~

~~(2) At least 1 cathodic protection pipe-to-soil test station must be located within the Class 1 to Class 3 location segment with a maximum spacing of 1⁄2 mile between test stations. In~~

~~**cases where obstructions or restricted areas prevent test station placement, the test station must be placed in the closest practical location. Annual monitoring of the cathodic protection pipe-to-soil test stations must meet §§ 192.463 and 192.465 for the Class 1 to Class 3 location segment.**~~

~~**(3) Install and maintain line-of-sight markers visible on the pipeline right-of-way, except in agricultural areas or large water crossings, such as lakes, where line-of-sight markers are not practical. An operator must replace line-of-sight markers as necessary and within 30 days after identifying a missing line-of sight marker.**~~

~~**(4) Interference surveys to address induced alternating current (AC) from parallel electric transmission lines, and other interference issues, such as direct current (DC), that may affect the Class 1 to Class 3 location segment. If an interference survey finds the interference current is greater than or equal to 100 amps per meter squared, impedes the safe operation of a pipeline, or may cause a condition that would adversely impact the environment or public safety, an operator must correct these instances within 15 months of the interference survey.**~~

~~**(5) Depth of cover must conform with § 192.327 for a Class 1 to Class 3 location segment or be remediated by adding markers at locations that do not meet the requirements of § 192.327 for a Class 1 location, lowering the pipe, adding cover, or installing safety barriers. Where the depth of cover is less than 24 inches in areas of nonconsolidated rock, the operator must either lower the pipe, or add cover over, or provide additional protection to withstand anticipated external loads (e.g. install concrete pads over pipe or other protective measures) the Class 1 to Class 3 location segment.**~~

~~**(6) Right-of-way patrols in accordance with paragraphs (a) and (c) of § 192.705 at least once per month, with intervals not to exceed 45 days for Class 1 to Class 3 location segments.**~~

~~**(7) Leakage surveys at intervals not exceeding 41⁄2 months, but at least four times each calendar year for Class 1 to Class 3 location segments.**~~

~~**(8) For shorted casings in Class 1 to Class 3 location segments, operators must clear the metallic short no later than 1 year after the short is identified or monitor the casing for corrosion growth through ILI inspection. For an electrolytic casing short, operators must remove the electrolyte from the casing/pipe annular space no later than 1 year after the short is identified**~~.

(g) ~~**Remote-control or automatic shutoff valves**~~ **Rupture-mitigation valves**. Mainline valves on both sides of Class 1 to Class 3 **or Class 2 to Class 3** location segments, and isolation valves on any crossover or lateral pipe designed to isolate a leak or rupture in a Class 1 to Class 3 **or a Class 2 to Class 3** location segment, must be operational remote-controlled or automatic shutoff valves ~~**with pressure sensors on each side of the mainline valves**~~. The maximum distance between such mainline valves must not exceed 20 miles.

~~(1) Valves installed in accordance with this paragraph must be closed as soon as practicable after a rupture is identified, but not to exceed 30 minutes.~~

~~(2) Valves installed in accordance with this paragraph must be operational at all times, controlled by a SCADA system, and monitored in accordance with § 192.631.~~

~~(3) Valves installed in accordance with this paragraph must be maintained in accordance with §§ 192.631(c)(2) and (c)(3), and 192.745.~~

~~(4) Automatic shutoff valves installed in accordance with this paragraph must be set so that, based on operating conditions and minimum and maximum flow model gradients, they will fully close within a maximum of 30 minutes following rupture identification. Automatic shutoff valve set-points must not be less than those required to actuate the valve before a downstream remote-control valve actuates. The automatic shutoff valve procedure and results for determining shutoff times must be reviewed for accuracy at least once each calendar year, with intervals not to exceed 15 months.~~

(h) Documentation. In addition to the documentation requirements specified in § 192.947, each operator must maintain records of all actions implemented to comply with paragraph(e) of this section for the life of the pipeline, including but not limited to subpart J pressure test records in accordance with § 192.517; and records of any pipeline assessments, surveys, remediations, maintenance, analyses, and other implemented actions.

~~(i) Notifications to PHMSA of integrity assessment program for class 1 to class 3 location segment changes. Each operator of a gas transmission pipeline that uses the integrity assessment program option for managing a Class 1 to Class 3 location segment change must notify PHMSA electronically in accordance with § 191.22(c)(2).~~

~~192.636 Transmission lines: Response to a rupture; capabilities of rupture-mitigation valves (RMVs) or alternative equivalent technologies.~~

~~(a) *Scope.* The requirements in this section apply to rupture-mitigation valves (RMVs), as defined in § 192.3, or alternative equivalent technologies, installed pursuant to §§ 192.179(e), (f), and (g) and 192.634.~~

* * * * *

§ 192.636 Transmission lines: Response to a rupture; capabilities of rupture-mitigation valves (RMVs) or alternative equivalent technologies.

(a) *Scope.* The requirements in this section apply to rupture-mitigation valves (RMVs), as defined in § 192.3, or alternative equivalent technologies, installed pursuant to §§192.179(e), (f), and (g)**, 192.618** and 192.634.

* * * * *

INGAA is including this text since section 192.712 was proposed in the Class NPRM. The following text represents the most updated code language codified on August 24, 2022. It was also discussed at the March 26-28, 2018, GPAC meeting.[98]

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

* * * * *

(c) *Dents and other mechanical damage.* To evaluate dents and other mechanical damage that could result in a stress riser or other integrity impact, an operator must develop a procedure and perform an engineering critical assessment as follows:

(1) Identify and evaluate potential threats to the pipe segment in the vicinity of the anomaly or defect, including ground movement, external loading, fatigue, cracking, and corrosion.

(2) Review high-resolution magnetic flux leakage (HR-MFL) high-resolution deformation, inertial mapping, and crack detection inline inspection data for damage in the dent area and any associated weld region, including available data from previous inline inspections.

(3) Perform pipeline curvature-based strain analysis using recent HR-Deformation inspection data.

(4) Compare the dent profile between the most recent and previous in-line inspections to identify significant changes in dent depth and shape.

(5) Identify and quantify all previous and present significant loads acting on the dent.

(6) Evaluate the strain level associated with the anomaly or defect and any nearby welds using Finite Element Analysis, or other technology in accordance with this section. Using Finite Element Analysis to quantify the dent strain, and then estimating and evaluating the damage using the Strain Limit Damage (SLD) and Ductile Failure Damage Indicator (DFDI) at the dent, are appropriate evaluation methods.

(7) The analyses performed in accordance with this section must account for material property uncertainties, model inaccuracies, and inline inspection tool sizing tolerances.

(8) Dents with a depth greater than 10 percent of the pipe outside diameter or with geometric strain levels that exceed the lessor of 10 percent or exceed the critical strain for the pipe material properties must be remediated in accordance with § 192.713, § 192.714, or § 192.933, as applicable.

(9) Using operational pressure data, a valid fatigue life prediction model that is appropriate for the pipeline segment, and assuming a reassessment safety factor of ~~5~~ 2 or greater for the assessment interval, estimate the fatigue life of the dent by Finite Element Analysis or other analytical technique that is technically appropriate for dent assessment and reassessment

[98] GPAC Meeting (Mar. 26-28, 2018), https://primis-meetings.phmsa.dot.gov/archive/GPAC-Slide_Presentation_-Gas_Rule_-_March_26_to_28_Mtg_5_-_FINAL.pdf at 149.

intervals in accordance with this section. Multiple dent or other fatigue models must be used for the evaluation as a part of the engineering critical assessment.

(10) If the dent or mechanical damage is suspected to have cracks, then a crack growth rate assessment is required to ensure adequate life for the dent with crack(s) until remediation or the dent with crack(s) must be evaluated and remediated in accordance with the criteria and timing requirements in § 192.713, § 192.714, or § 192.933, as applicable.

(11) An operator using an engineering critical assessment procedure, other technologies, or techniques to comply with paragraph (c) of this section must submit advance notification to PHMSA, with the relevant procedures, in accordance with § 192.18.

Note: INGAA supports § 192.712(c), as memorialized above, with the exception of the use of a safety factor of 5 in § 192.712(c)(9). INGAA supports the use of the safety factor of 2 as proposed in the Class NPRM.

§ 192.903 What definitions apply to this subpart?

* * * * *

High consequence area means an area established by one of the methods described in paragraphs (1) or (2) as follows:

(1) An area defined as—

(i) A Class 3 location under § 192.5; or

(ii) A Class 4 location under § 192.5;

or

(iii) Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or

(iv) Any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site; or

(v) Any Class 1 to Class 3 **or Class 2 to Class 3** location segment designated as a high consequence area in accordance with § 192.618(a).

(2) The area within a potential impact circle containing—

(i) 20 or more buildings intended for human occupancy, unless the exception in paragraph (4) applies; or

(ii) An identified site; or

(iii) Any Class 1 to Class 3 **or Class 2 to Class 3** location segment designated as a high consequence area in accordance with § 192.618(a).

While section 192.933 was not included in the Class NPRM, this regulation will also need to be updated to reflect the RIN-2 amendments as they are inextricably linked.

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

* * * * *

(d) ***Special requirements for scheduling remediation—***

* * * * *

(2) ***One-year conditions.*** Except for conditions listed in paragraphs (d)(1) and (3) of this section, an operator must remediate any of the following within 1 year of discovery of the condition:

* * * * *

(iv) Metal loss anomalies where a calculation of the remaining strength of the pipe at the location of the anomaly shows a predicted failure pressure, determined in accordance with § 192.712(b), less than 1.39 times the MAOP for Class 2 locations, and less than 1.50 times the MAOP for Class 3 and 4 locations. For metal loss anomalies in Class 1 locations with a predicted failure pressure greater than 1.1 times MAOP, an operator must follow the remediation schedule specified in ASME B31.8S (incorporated by reference, *see* § 192.7), section 7, Figure 4, in accordance with paragraph (c) of this section. **For Class 1 pipe within the Class 1 to Class 3 location segment, a metal loss anomaly with a predicted failure pressure of less than or equal to 1.39 times the MAOP.**

(v) Metal loss that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or could affect a girth weld, that has a predicted failure pressure, determined in accordance with § 192.712(b), of 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. **For Class 1 pipe within the Class 1 to Class 3 location segment, metal loss with a predicted failure pressure of less than or equal to 1.39 times the MAOP.**

(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. **For Class 1 pipe within the Class 1 to Class 3 location segment, metal loss with a predicted failure pressure of less than or equal to 1.39 times the MAOP.**

(vii) A crack or crack-like anomaly that has a predicted failure pressure, determined in accordance with § 192.712(d), that 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.

For Class 1 pipe within the Class 1 to Class 3 location segment, a crack or crack-like anomaly with a predicted failure pressure of less than or equal to 1.39 times the MAOP.

(3) ***Monitored conditions.*** An operator is not required by this section to schedule remediation of the following less severe conditions but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation. Monitored indications are the least severe and do not require an operator to examine and evaluate them until the next scheduled integrity assessment interval, but if an anomaly is expected to grow to dimensions or have a predicted failure pressure (with a safety factor) meeting a 1-year condition prior to the next scheduled assessment, then the operator must repair the condition:

* * * * *

(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. **For Class 1 pipe within the Class 1 to Class 3 location segment, metal loss with a predicted failure pressure of less than or equal to 1.39 times the MAOP.**

(vi) A crack or crack-like anomaly for which 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. **For Class 1 pipe within the Class 1 to Class 3 location segment, a crack or crack-like anomaly with a predicted failure pressure greater than 1.39 times the MAOP.**

* * * * *

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

(a) ***General requirements***.

(1)

* * * * *

(**xii**) Performing additional depth-of-cover surveys at roads, streams, and rivers;

(**xiii**) Remediating inadequate depth-of-cover~~;~~ **by lowering pipe, adding cover, or providing additional protection to withstand anticipated external loads ~~the Class 1 to Class 3 location segment~~;**

(x**i**v) Providing additional training to personnel on response procedures and conducting drills with local emergency responders; and

(~~xv~~ **xv**) Implementing additional inspection and maintenance programs.