BEFORE THE

UNITED STATES DEPARTMENT OF TRANSPORTATION

OFFICE OF THE SECRETARY OF TRANSPORTATION

WASHINGTON, D.C.

Notification of Regulatory Review	**Docket No. OST-2017-0069**

COMMENTS OF
THE AMERICAN GAS ASSOCIATION
THE AMERICAN PETROLEUM INSTITUTE
THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

November 9, 2017

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The American Gas Association (AGA), founded in 1918, represents more than 200 state regulated or municipal natural gas distribution companies. AGA members serve 95 percent of the 72 million natural gas customers, representing more than 160 million people in the United States who daily rely on natural gas service as a basic life necessity or use natural gas for business purposes. AGA and its members are deeply committed towards improving the safety performance of the natural gas industry. Numerous AGA programs and activities focus on the safe and efficient delivery of natural gas to customers. Safety continues to be the leading priority for AGA members.

API is the national trade association representing all facets of the oil and natural gas industry, which supports 9.8 million U.S. jobs and 8 percent of the U.S. economy. API's more than 650 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 more than 25 million Americans.

The Interstate Natural Gas Association of America ("INGAA") is a trade association that advocates regulatory and legislative positions of importance to the natural gas pipeline industry in North America. INGAA is comprised of 26 members, representing the vast majority of the interstate natural gas transmission pipeline companies in the United States. INGAA's members operate approximately 200,000 miles of pipelines, and serve as an indispensable link between natural gas producers and consumers.

I. INTRODUCTION

The American Gas Association (AGA), the American Petroleum Institute (API), and the Interstate Natural Gas Association of America (INGAA), collectively "the Associations," and our members are deeply committed to continuing to improve natural gas pipeline safety and working collaboratively with PHMSA and other stakeholders to develop regulations and initiatives that provide meaningful advancements in pipeline safety. In the past, this constructive relationship has resulted in numerous regulatory developments that have made significant enhancements to pipeline safety and have helped to achieve the excellent safety record of the nation's natural gas pipeline system. In that spirit, the Associations appreciate the opportunity to provide constructive input to the Department of Transportation as it reviews its existing regulations to "determine whether they are crafted effectively to solve current problems."[1] These comments only address PHMSA's regulations governing natural gas pipeline and storage facilities.[2]

The Associations believe that the regulatory review recommendations outlined below will support PHMSA in its objective to promulgate pipeline safety regulations that are "straightforward, clear, and designed to minimize burdens." The Associations' members stand ready to implement actions that will be required based upon new regulations PHMSA is currently developing, particularly those which are tied to congressional mandates. The changes to existing regulations recommended by the Associations will

[1] 82 Fed. Reg. 45750 (October 2, 2017).

[2] 49 C.F.R. Part 191 & 192. Review of hazardous liquid pipeline regulations is outside the scope of these document.

enable operators to reallocate resources to activities and programs that would benefit system integrity and public safety, including activities that may be required by proposed new regulations.

In addition to the Associations' primary regulatory review recommendations, the Associations have provided comments regarding some topics that PHMSA is currently reviewing. For each recommended regulatory review action below, the Associations provide:

- A summary statement of the recommended change
- The specific reference to the associated regulatory requirement
- The reason(s) for DOT/PHMSA to consider the recommended change
- Where possible, estimated cost savings to the industry, which may also include time savings for PHMSA and state agencies. The Associations developed these estimates in the 30-day time frame provided by the initial Notification of Regulatory Review. The Associations would be pleased to submit additional information on any of these proposals, including cost savings, if there is interest from PHMSA in receiving more details.

II. PRIMARY REGULATORY REVIEW RECOMMENDATIONS

A. GAS TRANSMISSION PIPELINE TOPICS

1. The Associations Recommend an Integrity Assessment Alternative for Managing Class Location Changes

Recommended Action(s): Develop an integrity assessment-based alternative for managing class location changes, in addition to the existing alternatives.

Reason(s):

1. When a class location change is triggered by the construction of new structures near an existing pipeline, the current regulations may require operators to replace pipe even when the existing pipe is in good condition. Such replacements do not necessarily improve pipeline safety, because processes and technologies are available for effectively managing pipeline safety in these segments.
2. An alternate approach to managing class location changes that leverages advanced assessment technologies to determine whether actual pipe condition warrants replacement would minimize the arbitrary replacement of good pipe. This approach also would capitalize on and further promote the expansion of Integrity Management processes and technologies throughout the nation's gas transmission pipeline network, a goal shared by industry, PHMSA, and public safety advocates.

CFR Code Sections Impacted: §192.611

Estimated Cost Savings: $200 - $300 million annually

The Associations suggest an alternative to existing PHMSA regulations governing the actions that operators must take when there is a change in the class location designation of a pipeline segment.[3]

When a class location change is triggered by the construction of new structures near an existing pipeline, the current regulations may require operators to replace pipe even when the existing pipe is in good condition. The Associations estimate that gas transmission pipeline operators incur annual costs of $200 – $300 million nationwide replacing pipe solely to satisfy the class location change regulations.[4] Such replacements do not necessarily improve pipeline safety, because processes and technologies are available for effectively managing pipeline safety in these segments. In fact, the substantial costs associated with these replacements may divert resources away from elective work that would enhance pipeline safety.[5]

The Associations suggest an alternate approach to managing class location changes (detailed below) that focuses on recurring Integrity Management assessments, in addition to the existing alternatives outlined in § 192.611(a). If adopted, this alternate approach will leverage advanced assessment technologies to determine whether actual pipe condition warrants replacement, thereby minimizing the arbitrary replacement of good pipe. This approach also would capitalize on and further promote the expansion of Integrity Management processes and technologies throughout the nation's gas transmission pipeline network, a goal shared by industry, PHMSA, and public safety advocates. This alternate approach also would improve economic efficiency by reducing the regulatory burden on gas transmission pipeline operators associated with class location changes and by allowing additional resources to be directed towards expanded use of Integrity Management processes. Finally, this alternate approach would fulfill the purposes of section 5 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which directed the Secretary to evaluate whether to "remove redundant class location requirements for gas transmission pipeline facilities that are regulated under an integrity management program….[6]"

Background

The class location concept, which pre-dates federal regulation of gas transmission pipeline safety, was an early method for differentiating areas along natural gas pipeline rights-of- way based on the potential consequences of a postulated pipeline failure. Current PHMSA regulations require operators to establish class location based on the number and type of structures within a specified distance from a gas transmission pipeline.[7] The rule that first incorporated class location in federal pipeline safety regulations was adopted in 1970 and predated the development and utilization of many of the pipeline integrity

[3] 49 C.F.R. § 192.611.

[4] Based on historical and forecasted INGAA member data representing approximately 100,000 miles of operating pipelines, and extrapolated for the 300,000 miles of gas transmission pipelines nationwide.

[5] Examples of work that may be deferred include pipeline modification projects enabling the accommodation of advanced inline inspection tools, as well as pipeline assessment projects using such tools.

[6] Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 §5, 125 Stat. 1907-1909 (2012). *See* §5(f)(3)(B)(ii).

[7] 49 C.F.R. § 192.5.

management processes and technologies that are commonplace today. Despite this, the class location change requirements have not fundamentally changed since 1970.

Integrity Management regulations, promulgated by PHMSA in 2004, specify the risk-based processes that pipeline operators must use to identify, prioritize, assess, evaluate, repair and validate the integrity of gas transmission pipelines that could, in the event of a leak or failure, affect High Consequence Areas ("HCAs") within the United States.[8] Pipeline operators often incorporate inline inspection assessments as part of their Integrity Management plans. Inline inspection technologies, such as high-resolution magnetic flux leakage tools, can precisely assess the presence of corrosion and other potential defects, allowing an operator to establish whether a pipeline segment requires remediation or replacement. In the preamble of the 2004 Integrity Management regulations, the Research and Special Programs Administration (PHMSA's predecessor) stated that "[t]he rule will provide a better technical justification to support waivers from existing requirements that mandate replacement of pipeline when population increases cause a change in class location. Experience may lead to future changes in the existing requirements."[9] PHMSA recognized that integrity assessments could establish the fitness of the pipe in lieu of pipe replacement. PHMSA and operators now have more than a dozen years of experience to use as a basis for determining how best to harmonize the class location change regulations with Integrity Management.

The alternatives to pipe replacement following a class location change now offered by PHMSA's regulations do not reflect the substantial developments in integrity management processes, technologies, and regulations over the last 15+ years. Consequently, the Associations suggest that an additional alternative to pipe replacement is warranted.[10] Currently, operators may choose to reduce the operating pressure of the pipeline, perform a pressure test on the pipeline, or apply for a Special Permit in lieu of replacing a pipe segment for which there has been a class location change. There are limitations associated with each of the alternate paths now available under PHMSA's rules.[11]

When an operator reduces operating pressure below historical operating levels, it may need to unacceptably restrict deliveries to natural gas customers – homes, businesses, power generators, manufacturing plants, export facilities, etc.

Pressure testing a pipeline may be practicable in select cases, especially for segments that cannot accommodate inline inspection. Still, the ability to use this option may be limited, because the test pressure required at higher class locations may exceed what a pipeline is designed to accommodate. Furthermore, removing a line from service and filling it with water to conduct a pressure test may interrupt service to pipeline customers, and ultimately consumers, and is unnecessary and impractical where pipeline integrity is known to be in good condition through utilization of robust integrity management processes.

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[8] 49 C.F.R. Part 192, Subpart O.

[9] Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines), 68 Fed. Reg. 69,778 (Dec. 15, 2003).

[10] The existing alternatives are important and should be retained, but the Associations suggest that an additional alternative is warranted.

[11] 49 C.F.R. § 192.611.

The Special Permit process has become protracted and unpredictable. The prescriptive data collection, inspection, and monitoring requirements that PHMSA often requires as part of a Special Permit process can vary on a case-by-case basis and may undermine the benefit of using modern risk-based integrity management processes and technologies. Furthermore, since Special Permits require periodic updating and renewal, operators cannot rely on permanent and consistent permit conditions in the long-term. (Permits can be revoked or permit conditions modified during subsequent renewals.)

Gas Transmission and Gathering NPRM

PHMSA's Safety of Gas Transmission and Gathering Pipelines proposed rulemaking ("NPRM") aims to expand Integrity Management assessments outside of HCAs to a new class of Moderate Consequence Areas (proposed new § 192.710).[12] Many of the Associations' members have voluntarily begun to implement an expansion of integrity management assessments beyond HCAs, which leverage advanced inspection technologies. The NPRM would substantially increase the proportion of onshore gas transmission pipelines required to be included in recurring integrity assessment programs. This would be a significant enhancement to the pipeline safety regulations, but would come at a significant cost – over $500 million per year on an ongoing basis.[13]

The expansion of recurring Integrity Management assessments in the NPRM provides a framework for developing an alternate program for managing class location changes. Developing an alternate approach (while retaining existing alternatives) to the class location change requirements that is based on recurring Integrity Management assessments and reflects the advancements that will be achieved by the NPRM could help substantially to offset some of the costs of the NPRM. That is, by avoiding the cost of unneeded pipe replacement, an alternate approach that reflects the new NPRM requirements would mitigate, to some degree, the cost to implement the changes that will come when the NPRM results in a final rule. In addition, as noted previously, the alternate approach proposed by the Associations would fulfill the purposes of section 5 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011.[14]

Alternate Approach to Class Location Changes

The Associations recommend that PHMSA develop an alternate approach for managing class location changes that focuses on recurring Integrity Management assessments to confirm actual pipe condition and determine whether pipe condition warrants replacement. PHMSA should leverage the proposed § 192.710, which would extend *recurring* Integrity Management assessments outside of HCAs. Existing § 192.611(a) provides three alternatives that operators can apply whenever a change in structure count indicates a change in class location for a pipeline segment. The Associations propose a *fourth alternative* for managing class location changes within § 192.611(a) that would include compliance with proposed § 192.710 (outside of HCAs)[15] or with existing § 192.921 (within of HCAs). Baseline integrity assessments for

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[12] Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, 81 Fed. Reg. 20,722 (Apr. 8, 2016).
[13] INGAA "Safety of Gas Transmission Pipeline Rule Cost Analysis" (Jul. 7, 2016). http://www.ingaa.org/File.aspx?id=29873&v=6c2c0f15.
[14] Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 §5, 125 Stat. 1907-1909 (2012).
[15] Although proposed § 192.710(a) defines the segments which PHMSA proposes to include within the assessment program outside of HCAs, the Associations' propose that *any non-HCA class location change segment* managed

segments new to the recurring assessment program could be completed within 24 months of the class location change – consistent with the current timelines in § 192.611.

Additionally, for any pipeline segment that does not have traceable, verifiable, and complete records of a hydrostatic pressure test to support the segment's existing Maximum Allowable Operating Pressure ("MAOP") and where a class location change has occurred, the Associations' proposed fourth alternative within § 192.611(a) would require operators to perform MAOP Reconfirmation.[16] MAOP Reconfirmation is a *one-time* process for confirming a pipeline's material strength that PHMSA proposed in the NPRM (proposed new § 192.624) to address certain pipeline segments that do not have traceable, verifiable, and complete records supporting the current MAOP.[17]

Furthermore, the new corrosion control regulations proposed in the NPRM, and recently endorsed by the Gas Pipeline Advisory Committee, provide further support for an alternative approach to managing class location changes. These new corrosion control regulations will apply to all pipeline segments, including segments that have experienced a class location change. These regulations will require operators to implement additional preventative and mitigative measures to manage the threat of corrosion. New requirements include provisions related to coating surveys following backfill, cathodic protection monitoring and remediation, mitigation of interference current, and internal corrosion monitoring and remediation.[18] The inclusion of such corrosion control measures as part of a program for managing the integrity of segments that have experienced a class location change provides further justification for developing the new codified alternative for managing class location changes using recurring Integrity Management assessments that the Associations are suggesting.

To ensure that operators can utilize the most effective and efficient methods and technologies for continuously enhancing pipeline safety, PHMSA should incorporate into regulation the Associations' proposed alternative approach for managing class location changes that focuses on recurring integrity management assessments.

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using the Associations' proposed recurring assessment alternative should be required to be included within a recurring pipeline assessment program as described in § 192.710(a).

[16] Although proposed § 192.624(a) defines the segments for which operators would be required to conduct MAOP Reconfirmation, the Associations propose that *any class location change segment* managed using the Associations' proposed recurring assessment alternative should be required to undergo MAOP Reconfirmation, if the segment does not have traceable, verifiable, and complete records of a hydrostatic pressure test to support the segment's existing MAOP.

[17] The Associations recommended targeted improvements to PHMSA's MAOP Reconfirmation process in July 2016 comments to the NPRM.

[18] Approved voting slides for the June 6-7 2017 GPAC meeting are located at the following link: https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=872 .

2. The Associations Recommend Modifications to Anomaly Response Regulations

Recommended Action(s): Revise regulations governing the actions that operators must take in response to assessment findings so that the regulations are better aligned with advances in technology and published technical standards. Specifically, PHMSA should provide an engineering analysis alternative for managing "a dent that has any indication of metal loss" and establish specific parameters for prioritizing potentially injurious anomalies requiring immediate response.

Reason(s):

1. The language in PHMSA's existing anomaly response regulations (originally published in 2003) has not kept pace with advancements in inline assessment technology and is not aligned with published technical standards in some instances. As a result, a large and growing portion of operators' resources is spent responding to non-injurious anomalies. Specifically, the requirement to respond immediately to "a dent that has any indication of metal loss" no longer reflects the capabilities of today's inline inspection integrity assessment technologies to detect and characterize these anomalies.
2. Not all dents that have "any indication of metal loss" present an immediate risk. Excavations of non-injurious anomalies do not necessarily improve pipeline safety, and, in fact, the substantial costs associated with these replacements may divert resources from elective work that could enhance pipeline safety. Moreover, excavations of non-injurious anomalies increase the risk of damaging the pipe or its coating, or introducing additional stresses by disturbing the pipeline to make an unnecessary repair.

CFR Code Sections Impacted: §192.933

Estimated Cost Savings: $9 - $14 million annually for the Associations' proposed modifications to the existing requirements in HCAs. Cost savings will be $50 - $100 million annually if PHMSA also modifies its proposed anomaly response regulations for pipelines outside of HCAs.

The Associations recommend that PHMSA revise its regulations governing the actions that natural gas transmission pipeline operators must take in response to assessment findings (§ 192.933(d)), so that the regulations are better aligned with advances in technology and published technical standards.[19]

Gas transmission pipeline operators are required to conduct recurring integrity assessments of pipeline segments in HCAs as part of continuous Integrity Management Programs. If these integrity assessments identify certain anomalous pipe conditions, PHMSA's regulations prescribe how quickly an operator must expose the pipeline (through excavation) to evaluate the anomaly further. As outlined previously, the Associations' members strongly support recurring integrity assessment programs and prompt, risk-based response and remediation of any injurious anomalies identified through assessment.

However, the language in PHMSA's existing anomaly response regulations (originally published in 2003) has not kept pace with advancements in inline assessment technology and is not aligned with published technical standards in some instances. As a result, a large and growing portion of operators' resources is spent responding to non-injurious anomalies. Specifically, the requirement to respond immediately to "a

[19] 49 C.F.R. § 192.933(d).

dent that has any indication of metal loss" no longer reflects the capabilities of today's inline inspection integrity assessment technologies to detect and characterize these anomalies.

The capabilities of inline inspection tools have improved dramatically over the past 15 years.[20] These include improvements in sensitivity and detection limits, anomaly sizing accuracy, and discrimination between anomaly types. Many of the "indications" that modern inline inspection tools can now identify represent small amounts of metal loss which present minimal public risk; such non-injurious anomalies were often not detected in the past using older technologies. When utilizing higher-capability, higher-sensitivity tools, there is also the potential for false-positive indications.[21] In some cases, operators are re-excavating and re-inspecting the same section of pipe in consecutive reassessment cycles, because inline inspection tool capabilities and sensitivities have improved since the prior assessment cycle and the tools are locating additional, often non-injurious indications. Simply put, "any indication" means something very different today than it did when the anomaly response regulations were adopted approximately 15 years ago. The current regulatory text that does not reflect published technical standards, coupled with the advancement in inspection technology, has required operators to excavate in-service pipelines to inspect non-injurious anomalies at an increasing rate.

The Associations estimate that gas transmission pipeline operators incur annual costs of $9 – 13 million nationwide excavating pipelines in response to non-injurious "dent that has any indication of metal loss" anomalies.[22] Such excavations of non-injurious anomalies do not necessarily improve pipeline safety, and, in fact, the substantial costs associated with these replacements may divert resources from elective work that could enhance pipeline safety.[23] Moreover, excavations of non-injurious anomalies increase the risk of damaging the pipe or its coating, or introducing additional stresses by disturbing the pipeline to make an unnecessary repair. The significant excavation work required to respond to these anomalies can also be a nuisance to the nearby community.

The Associations propose an alternative approach for responding to "a dent that has any indication of metal loss." The Associations also propose additional defining language that should be added to the regulatory text to specify how dent anomalies should be prioritized for response and evaluation. The Associations' proposed revisions reflect advancements in inline inspection technology, published technical standards, and existing language found elsewhere in PHMSA's regulations. Specific recommended revisions to the regulatory text are included below.

Revising the "dent that has any indication of metal loss" anomaly response criteria would improve economic efficiency by reducing the regulatory burden on gas transmission pipeline operators without

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[20] For a brief review of historical, present and future ILI capabilities, *see*: Rau J, Kirkwood M. Hydrotesting and In-Line Inspection: Now and in the Future. ASME. International Pipeline Conference, Volume 1: Pipelines and Facilities Integrity ():V001T03A055. doi:10.1115/IPC2016-64105.

[21] For example, on a pipe without any anomalous conditions, an inline inspection tool may call out a small "indication" of an anomalous condition within its accuracy range.

[22] Based on historical and forecasted INGAA member data representing approximately 7,500 miles of HCAs. The range of costs reflects an anticipated increase in HCA mileage that can accommodate inline inspection over time.

[23] Examples of work that may be deferred include pipeline modification projects enabling the accommodation of advanced inline inspection tools, as well as pipeline assessment projects using such tools.

decreasing safety. Furthermore, since PHMSA proposes in its 2016 NPRM to extend this anomaly response criteria beyond HCAs to all gas transmission pipelines, revising this criteria would free up operators' resources that could be used to achieve the goals of the NPRM while reducing the potential burden of the proposed new regulations.[24] The Associations estimate that pipeline operators would incur additional costs of $50 million - $100 million per year if the current requirement to respond immediately to "a dent that has any indication of metal loss" is extended without modification to all pipeline segments.[25]

Technical Background

The preeminent technical resource that addresses the design, fabrication, installation, inspection, and testing of gas transmission pipeline systems is the American Society of Mechanical Engineers Code for Pressure Piping, B31.8 ("ASME B31.8"). ASME B31.8 was developed and is updated through an American National Standards Institute (ANSI) process and reflects the consensus of many of the nation's leading experts in mechanical engineering and metallurgy. The 2007 edition of ASME B31.8 is currently incorporated by reference in PHMSA's regulations.[26] Both the 2007 and the current (2016) editions of ASME B31.8 provide specific thresholds by which an operator can determine whether a dent with metal loss anomaly is injurious. Per ASME B31.8, dents that contain metal loss are injurious if **1)** the dent exceeds a depth of 6% of the nominal pipe diameter, **2)** a calculation of the remaining strength of the pipe shows a predicted failure pressure less than the MAOP or **3)** there is external mechanical damage to the pipe surface, which includes features such as creasing of the pipe wall, gouges, scrapes, smeared metal, and metal loss ***not due to corrosion***.[27]

Separate PHMSA regulatory requirements for anomaly response in HCAs already address items **1)** and **2)** above by prescribing specific timelines for responding to dents that exceed a depth of 6% of the nominal pipe diameter or where corrosion has reduced the remaining strength of the pipe below 1.1 times the MAOP.[28] These requirements are based on engineering analysis methods established by ASME and others for assessing these anomalous conditions. Therefore, the additional existing requirement to respond immediately to "a dent that has any indication of metal loss" is not necessary to address dents that exceed a depth of 6% of the nominal pipe diameter or where corrosion has reduced the remaining strength of the pipe below 1.1 times the MAOP.

Various technical studies support ASME B31.8's treatment of corrosion-induced metal loss within a dent as a separate condition from the dent itself for purposes of prioritizing an operator's response. In a series of tests performed for the American Petroleum Institute (API), dent anomalies as deep as 12% of the pipe

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[24] Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, 81 Fed. Reg. 20,722 (Apr. 8, 2016).
[25] Based on data collected for pipelines in HCAs and non-HCAs as part of INGAA's "Safety of Gas Transmission Pipeline Rule Cost Analysis" (Jul. 7, 2016). http://www.ingaa.org/File.aspx?id=29873&v=6c2c0f15. No discount rate assumed. This cost range is also validated based on newly-collected historical and forecasted INGAA member data representing approximately 7,500 miles of HCAs, extrapolated for the 193,000 miles of gas transmission pipelines nationwide that can accommodate inline inspection. The range of costs reflects an anticipated increase in pipeline mileage that can accommodate inline inspection over time.
[26] 49 C.F.R. § 192.7.
[27] ASME B31.8 – 2016, § 851.4.1(f)
[28] §§ 192.933(d)(1)(i), 192.933(d)(2)(i), 192.933(d)(3)(i), and 192.933(d)(3)(ii),

outer diameter with 50% simulated metal loss failed at pressure levels greater than that predicted by remaining strength calculations using the RSTRENG methodology.[29] A task group studying this issue with assistance from the Gas Technology Institute (GTI) as part of the 2003 ASME B31.8 update concluded that "plain dents do not adversely affect the burst strength of sound pipe" and therefore "corrosion indicated in a rock-induced dent may be evaluated, graded, or prioritized in the same manner as metal-loss corrosion features found elsewhere on the pipe.[30]" The additional existing requirement to respond immediately to "a dent that has any indication of metal loss" is not necessary to address dents with metal loss that exceed a depth of 6% of the nominal pipe diameter or where corrosion has reduced the remaining strength of the pipe below 1.1 times the MAOP, because other regulatory requirements address these anomalies.

The third injurious condition identified in ASME B31.8 that could be associated with "a dent that has any indication of metal loss" is external mechanical damage to the pipe surface, which includes features such as creasing of the pipe wall, gouges, scrapes, smeared metal, and metal loss ***not due to corrosion***.[31] The Associations believe PHMSA's existing requirement to respond immediately to "a dent that has any indication of metal loss" is primarily aimed at prioritizing responses to mechanical damage. However, the current regulatory language includes non-injurious anomalies other than those caused by mechanical damage as conditions requiring immediate response. As outlined above, ASME B31.8 and other existing PHMSA regulations describe the engineering analysis (remaining strength analysis) that must be completed to evaluate dents with metal loss due to corrosion. The requirement to respond immediately to "a dent that has any indication of metal loss" should be refined to reflect these separate processes. The experience of the Associations' members indicates that the significant majority of dents with metal loss identified through inline inspection tools are associated with ***corrosion-related*** metal loss levels that are not injurious when examined and do not require repair in accordance with ASME B31.8 criteria.

Furthermore, PHMSA's existing regulations do not consider the orientation of a dent that has any indication of metal loss (e.g., top versus bottom of the pipe) to establish the likelihood that the metal loss is the result of mechanical damage rather than non-injurious corrosion. The top of a pipe is more exposed to potential mechanical damage than the bottom of a pipe. Dents with metal loss on the bottom of the pipe often do not warrant an immediate response since the dents are typically caused by rocks and any metal loss is typically corrosion-related.

Requiring an immediate repair for anomalies that do not presently represent injurious conditions conflicts with PHMSA's intent in establishing immediate response conditions. As stated previously, excavations of non-injurious anomalies do not necessarily improve pipeline safety. Addressing non-injurious dents with metal loss as immediate response conditions conflicts with ASME's published technical standards for gas pipeline integrity management, ASME B31.8S, which PHMSA has incorporated by reference as the basis

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[29] Kiefner, J. F., and Alexander, C. R., "Effects of Smooth and Rock Dents on Liquid Petroleum Pipelines (Phase 2)", Addendum to API Publication 1156 (October 1999).

[30] Rosenfeld MJ, Pepper JW, Leewis K. Basis of the New Criteria in ASME B31.8 for Prioritization and Repair of Mechanical Damage. ASME. International Pipeline Conference, 4th International Pipeline Conference, Parts A and B ():647-658. doi:10.1115/IPC2002-27122.

[31] ASME B31.8 – 2016, § 851.4.1(f)

of its Integrity Management regulations for pipelines in HCAs.[32] For example, ASME B31.8S-2004, Section 7.2 classifies responses into three groups: immediate, scheduled, and monitored. According to Section 7.2, an assessment indication that warrants an immediate response is one that "shows the defect is at a failure point" and "might be expected to cause immediate or near-term leaks or ruptures based on their known or perceived effects on the strength of the pipeline." As a result of the increasing capabilities of assessment tools in recent years, an identified "dent that has any indication of metal loss" often presents no "immediate or near-term" threat of a leak or rupture.

The Associations propose an alternative approach for responding to "a dent that has any indication of metal loss." The Associations also propose adding defining language to the regulatory text to specify which dent anomalies should be prioritized for response and evaluation. The Associations' proposed alternative and revisions reflect advancements in inline inspection technology published technical standards, and existing language elsewhere in PHMSA's regulations.

Alternative Approach to Dent Anomaly Response Criteria

As noted previously, many of the "dent that has any indication of metal loss" anomalies identified by modern inline assessment technologies reflect small, non-injurious dents or minor, non-injurious indications of metal loss. As described in ASME B31.8, established engineering methods exist to use inline inspection assessment data to evaluate certain dent with metal loss anomalies. Such engineering analysis methods assist an operator in identifying the specific, potentially-injurious anomalies that warrant excavation and further evaluation. In fact, PHMSA's existing response criteria regulations for segments in HCAs already allow an operator to perform engineering analyses to demonstrate that a dent of certain types is non-injurious, and then treat the anomaly as a "monitored condition."[33] For monitored conditions, while operators are not required to perform in-field excavation of an anomaly, operators *are* required to "record and monitor the anomaly during subsequent risk assessments and integrity assessments for any change that may require remediation." The Associations recommend that PHMSA add an alternative to allow operators to ***conduct an engineering analysis*** to demonstrate that a "dent that has any indication of metal loss, cracking or a stress riser" is non-injurious and does not pose a public safety threat, and then treat the anomaly as a ***monitored condition***.

The proposed engineering analysis would consist of an evaluation of the anomaly geometry and other features using an established engineering method to confirm the dent is non-injurious. The specific engineering method will be tailored to the unique features of the anomaly, but appropriate methods could include dent strain calculations (e.g., ASME B31.8 Appendix R) and remaining strength calculations for corrosion induced metal loss (*e.g.*, ASME B31G[34], PRCI PR-3-805 (R-STRENG)[35]). An operator may also develop a process for leveraging inline inspection data for discriminating between dents likely to have

[32] 49 C.F.R. § 192.7.
[33] § 192.933(d)(3)(ii) and § 192.933(d)(3)(iii),
[34] ASME/ANSI B31G-1991, "Manual for Determining the Remaining Strength of Corroded Pipelines," 2004, (ASME/ANSI B31G).
[35] AGA, Pipeline Research Committee Project, PR-3-805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe," (December 22, 1989), (PRCI PR-3-805 (R-STRENG))

been caused by mechanical damage and contain gouging/cracking from dents caused by rocks and with corrosion-induced metal loss. To evaluate cracking in dents and the potential for fatigue-induced failures, screening methodologies exist for gas pipeline operators to use to evaluate and document susceptibility of a pipeline to pressure cycle induced fatigue.[36] Natural gas pipelines generally have stable pressures, and as a result fatigue remains a comparatively minor risk component of the overall spectrum of threats to natural gas pipeline safety.[37]

Additionally, the Associations propose to align PHMSA's regulations with ASME B31.8's focus on dents caused by mechanical damage. PHMSA's existing anomaly response regulations do not consider the orientation (e.g., top versus bottom of the pipe) of "a dent that has any indication of metal loss" to establish the likelihood that the metal loss is the result of mechanical damage caused by excavation rather than non-injurious corrosion. PHMSA's regulations for smooth dents *do* consider orientation and the Associations propose to draw upon that rationale for dents with metal loss. Dents between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) are considered to primarily result from mechanical damage.[38] Gouging caused by mechanical damage can be more difficult to size and evaluate reliably than corrosion-induced metal loss. Therefore, the Associations propose to address "a dent ***located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe)*** that has any indication of metal loss, cracking or a stress riser" as an "immediate response" condition, unless an engineering analysis confirms that the dent is non-injurious, as discussed above.

ASME B31.8 treats mechanical damage as an injurious condition ***separate*** from metal loss caused by corrosion. ASME B31.8S treats dents with gouges (a severe type of mechanical damage) as an immediate response condition – but **ASME B31.8S does not treat *all*** dents with ***any*** indication of metal loss as an immediate response condition. In particular, dents on the bottom of the pipe are more likely to be the result of rocks during original construction or emergence of rocks through backfill while in service, and any associated metal loss is more likely to be corrosion-related. Such anomalies are not the result of mechanical damage and, consequently, are treated separately in ASME B31.8 and ASME B31.8S. ASME B31.8S outlines a process for operators to schedule responses to corrosion anomalies based on remaining strength calculations and predicted failure pressure.[39] Thus, the Associations propose to address "a dent ***located between the 4 o'clock position and the 8 o'clock position (bottom ⅓ of the pipe)*** that has any indication of metal loss, cracking or a stress riser" as a one-year scheduled response condition, unless an engineering analysis confirms that the dent is non-injurious, as discussed above. There is a clear precedent in PHMSA's existing anomaly response regulations for such distinction between top-side and bottom-side dents. Smooth dents located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6% of the pipeline diameter are treated as one-year response conditions, while such dents on the bottom ⅓ of the pipe are treated as monitored conditions.

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[36] BMT Fleet Technologies, Fatigue Considerations in Natural Gas Transmission (June 30, 2016)

[37] M.J. Rosenfeld, & J.F. Kiefner, Pipeline Research Council International Inc., Basics of Metal Fatigue in Natural Gas Pipeline Systems – A Primer for Gas Pipeline Operators, Contract PR-302-03152 (June 2006)

[38] 49 CFR 192.933

[39] ASME B31.8 – 2016, § 7.2.1

PHMSA should also consider clarifying the dent anomaly response criteria to acknowledge the increasing capability and sensitivity of inline inspection assessment technologies. PHMSA should consider providing a conservative general depth threshold for separating injurious anomalies requiring immediate response. ASME B31.8 and PHMSA's response criteria regulations provide such a general threshold for establishing which smooth dents are potentially injurious: a depth of 6% of the nominal pipe diameter. For "a dent that has any indication of metal loss, cracking or a stress riser," PHMSA should consider the Construction section of the gas pipeline regulations, where operators are required to repair or remove dents with "more than 2 percent of the nominal pipe diameter in pipe over 12¾ inches (324 millimeters) in outer diameter" for pipelines to be operated at a pressure that produces a hoop stress of 40 percent or more of SMYS.[40] This workmanship criterion has been included in ASME B31.8 since the 1960s and, like other criteria of the time, is conservative to ensure that a pipeline is not installed with features that will grow to the point of failure.

Applying a similar, conservative threshold for dents that have "any indication of metal loss, cracking or a stress riser" on pipelines in operation could help appropriately focus the regulations on injurious anomalies requiring immediate repair. The Associations propose that PHMSA consider requiring only a dent **"*<u>with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe)</u>*** that has any indication of metal loss, cracking or a stress riser" as immediate response condition. Dents with any indication of metal loss, cracking, or a stress riser on the upper ⅔ of the pipe that are below this depth threshold could be addressed as one-year scheduled response conditions. For anomalies that are scheduled as one-year response conditions, operators would have sufficient time to conduct an engineering analysis to determine whether excavation and further evaluation is appropriate. The Associations are committed to further technical dialogue with key stakeholders regarding an appropriately conservative general threshold and this proposed tiered approach to prioritizing dents with metal loss – the Gas Pipeline Advisory Committee would be an appropriate forum for this discussion.

The Associations' Proposed Alternate Approach to Dent Anomaly Response Criteria – **<u>Proposed Additions to Regulatory Text in Red and Underlined</u>**

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

[…]

(d) *Special requirements for scheduling remediation—*

(1) *Immediate repair conditions.* An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, section 7 in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:

(i) A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include ASME/ANSI B31G (incorporated by reference, *see* §192.7), PRCI PR-3-805 (R-STRENG) (incorporated by

[40] 49 CFR 192.309(b)(3)(ii).

reference, *see* §192.7), or an alternative equivalent method of remaining strength calculation.

(ii) A dent **with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe)** that has any indication of metal loss, cracking or a stress riser.

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

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).

(ii) A dent with a depth greater than 2% of the pipeline's 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 seam weld.

(iii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 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 ⅓ of the pipe) that has any indication of metal loss, cracking or a stress riser.

(iv) A dent with a depth equal to or less than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) that has any indication of metal loss, cracking or a stress riser.

(3) *Monitored conditions.* 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:

(i) A dent with a depth greater than 6% 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 ⅓ of the pipe).

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.

(iii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.

(iv) A dent that has any indication of metal loss, cracking or a stress riser and an engineering analysis demonstrates that the dent is non-injurious and does not pose a public safety threat.

Incident Trends Support the Associations' Proposed Modifications

INGAA conducted a review of all onshore gas transmission pipelines incidents (inside and outside of HCAs) reported to PHMSA from 2010-2016. INGAA identified 9 dent-related incidents during this period; approximately 1% of all onshore gas transmission pipeline incidents during this period. Of these 9 dent-related incidents, one occurred in an HCA. Another incident was caused by stress corrosion cracking at a stress concentrator (it is unclear whether the concentrator was a dent), and corrosion was not a factor in any of the other incidents. None of these incidents involved injuries or fatalities.

The low frequency of incidents caused by dents, particularly dents with corrosion-induced metal loss, supports the Associations' proposal to add an engineering analysis approach as an alternative for managing these anomalies as monitored conditions. Many operators are currently spending significant resources to respond immediately to every dent that has any indication of metal loss – this burden is not commensurate with the risk associated with these anomalies. The Associations' proposed alternative would allow operators to focus resources on threats that present higher risk to their pipelines.

Gas Transmission and Gathering NPRM

PHMSA's NPRM extends anomaly response criteria currently required for pipeline segments in HCAs to all pipeline segments (proposed new § 192.713).[41] This includes the immediate response requirement for "a dent that has any indication of metal loss, cracking or a stress riser." Since only approximately 7% of onshore gas transmission pipelines are located in HCAs, the NPRM would substantially expand the application of this response criteria. INGAA estimates that PHMSA's collective proposed additions to HCA response criteria and expansion of such criteria to non-HCAs would add annual costs of over $600 million to natural gas transmission operators.[42] The Associations estimate that pipeline operators would incur additional costs of $50 million - $100 million per year addressing dents that have any indication of metal loss if this specific existing requirement is extended to all pipeline segments.[43]

The Associations' members strongly support recurring integrity assessment programs and prompt, risk-based response and remediation of any injurious anomalies identified through assessment. Yet, the potential expansion of dent anomaly response criteria to all pipeline segments amplifies the need for technically-supported, risk-appropriate response criteria. Applying the requirement to immediately respond to "a dent that has *any* indication of metal loss" to all pipeline segments would substantially increase the burden associated with this response criterion (which currently only applies in HCAs) and not lead to greater safety in many instances. Alternatively, adopting the Associations' proposed engineering analysis alternative and revisions to the existing response criteria in HCAs would free up resources that are currently being expended addressing non-injurious anomalies. These resources could instead be used towards achieving the NPRM's goal to expand response criteria outside of HCAs. Furthermore, adopting the Associations' proposed engineering analysis alternative and proposed specific parameters for prioritizing injurious anomalies that require immediate response would reduce the potential burden of the proposed new regulations.[44] Similarly, the Associations' proposal would further promote and facilitate

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[41] Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, 81 Fed. Reg. 20,722 (Apr. 8, 2016).
[42] INGAA "Safety of Gas Transmission Pipeline Rule Cost Analysis" (Jul. 7, 2016). http://www.ingaa.org/File.aspx?id=29873&v=6c2c0f15. Assumes 7% discount rate.
[42] INGAA recommended targeted improvements to PHMSA's proposed changes to anomaly response and repair requirements inside and outside of HCAs in its July 2016 comments to the NPRM. http://www.ingaa.org/File.aspx?id=29912&v=ccaef774.
[43] Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, 81 Fed. Reg. 20,722 (Apr. 8, 2016).

the deployment of recurring Integrity Management assessments outside of HCAs, a goal shared by industry, PHMSA, and public safety advocates and proposed in the NPRM.

B. GAS DISTRIBUTION PIPELINE TOPICS

1. Services Off Production, Gathering, or Transmission Lines ("Farm Taps")

Recommended Deregulatory Action(s): Revise §192.740 and §192.1003 to allow operators the choice of managing risks associated with Farm Taps under either of these regulatory sections.

Reason(s):

1. 49 CFR §192.740 moves from a risk-based approach for pipeline safety to a prescriptive approach by requiring operators to perform frequent mandatory inspections of Farm Taps, regardless of their performance, and no longer allows the risks associated with Farm Taps to be considered under a holistic Distribution Integrity Management Program. The burden imposed by §192.740 is not justified by the benefit.
2. Preliminary Regulatory Impact Assessment (PRIA) justifying this recent regulation contained significant flaws

CFR Code Sections Impacted: §192.740 and §192.1003

Estimated Cost Savings: Approximately $122 Million

In February 2017, the Pipeline and Hazardous Materials Safety Administration (PHMSA) released the Operator Qualification, Cost Recovery, & Other Pipeline Safety Changes Final Rule,[45] which went into effect on March 24, 2017.

The rule included new provisions that require operators to periodically inspect every "service line directly connected to a production, gathering, or transmission pipeline that is not operated as part of a distribution system," commonly known throughout industry as "Farm Taps." Furthermore, PHMSA amended Part 192 regulations so that operators could no longer address Farm Taps under their Distribution Integrity Management Program (DIMP)[46].

Farm Taps have historically been included in an operator's DIMP plan. Under DIMP, the risks associated with Farm Taps have been risk ranked and the appropriate mitigation measures to reduce identified risks have been taken. With the new rulemaking, Farm Taps must now be removed from DIMP plans, those plans must be reevaluated to rank remaining risks, and new non-risk-based prescriptive actions must be performed. This is contrary to the performance-based approach that PHMSA has adopted for its integrity management regulations. In addition, some operators will need to perform front-end activities to rebuild Farm Taps to make them capable of inspection per the new requirements in §192.740. This may result in temporary disruption of gas service to customers.

[45] 49 C.F.R §192.740 2017
[46] 49 C.F.R §192.1003 2017

The Associations question the pipeline safety enhancements attributed to the new regulatory requirement. Operators have continuously monitored Farm Taps for heightened levels of risk under their DIMP plans since 2011 when the DIMP rule was promulgated. Operators currently are obligated to periodically perform leak and atmospheric corrosion surveys on these assets under §192.723(b)(2) and §192.481. This provides operators an opportunity to visually inspect the facility and to identify any abnormal operating conditions.

An overwhelming majority of distribution operators have not identified any elevated risk associated with the Farm Taps through their DIMP risk identification processes. PHMSA even acknowledged in its PRIA that the risk introduced by Farm Taps to the public is "generally low." Furthermore, PHMSA did not cite any pipeline incident in either the rule or the PRIA that would warrant the new inspection requirements.

The Associations encourage PHMSA to revise §192.740 and §192.1003 to give operators the flexibility to address Farm Taps under either of these regulatory sections. This action would maintain pipeline safety while reducing regulatory burden.

The Associations have attached some cost information for managing Farm Taps in the Appendix.

Below are the changes that the Associations recommend making to the federal pipeline safety code:

§192.740 Pressure regulating, limiting, and overpressure protection – Individual service lines originating in production, gathering or transmission pipelines.

(a) This section applies, except as provided in paragraph (c), to any service line that originates from a production, gathering, or transmission pipeline that is not operated as part of a distribution system.

(b) Each pressure regulating/limiting device, relief device, automatic shutoff device, and associated equipment must be inspected and tested at least once every 3 calendar years, not exceeding 39 months, to determine that it is:

(1) In good mechanical condition;

(2) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

(3) Set to control or relieve at the correct pressure consistent with the pressure limits of § 192.197; and to limit the pressure on the inlet of the service regulator to 60 psi (414 kPa) gage or less in case the upstream regulator fails to function properly; and

(4) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

(c) This section does not apply to equipment installed on:

(1) Service lines that only serve engines that power irrigation pumps;

(2) Service lines that are included under a Distribution Integrity Management program under 49 CFR Subpart P.

§192.1003 What do the regulations in this Subpart cover?

(a) *General*. Unless exempted in paragraph (b) this Subpart prescribes minimum requirements for an IM program for any gas distribution pipeline covered under this part, including liquefied petroleum gas systems. A gas distribution operator, other than a master meter operator or a small LPG operator, must follow the requirements in §§ 192.1005-192.1013 of this Subpart. A master meter operator or small LPG operator of a gas distribution pipeline must follow the requirements in §192.1015 of this Subpart.

(b) *Exceptions*. This subpart does not apply to an individual service line directly connected to a transmission, gathering, or production pipeline **where the pressure regulating, limiting, and over pressure protection are maintained pursuant to §192.740.**

2. Atmospheric Corrosion Monitoring

Recommended Action(s): For distribution pipelines, remove the prescriptive requirement for atmospheric corrosion monitoring to be conducted at least once every 3 calendar years, not to exceed 39 months. Instead, provide operators the ability to address the risk of atmospheric corrosion explicitly in their DIMP plan for distribution pipelines and assets that require monitoring/inspection. This change should not apply to onshore gas transmission and gathering.

CFR Code Sections Impacted: §192.481, §192.1007 and §192.1015

Reason(s):

1. Eliminate overlapping and duplicative regulations, such as the overlap between DIMP and atmospheric corrosion inspections
2. Enable efficient use of resources by aligning inspections with commensurate risk
3. Although deviations from inspection frequencies are permitted under §192.1013, the process to obtain regulatory approval from each state agency is extremely burdensome

Estimated Cost Savings: Undetermined, but potentially substantial

Pipeline operators are currently required to inspect for atmospheric corrosion of all pipelines exposed to the atmosphere every 3 years for onshore gas pipelines and annually for offshore pipelines. Atmospheric corrosion requirements are a classic example of the prescriptive approach that was taken when Part 192 regulations were initially developed. This requirement specifies that the operator must inspect for atmospheric corrosion on all of its meter sets and exposed pipelines at an identical frequency, regardless of whether the operator's facilities are located in a humid, temperate, or arid climate. This prescriptive regulation is contrary to the risk-based methodology currently in PHMSA's regulations for managing the integrity of pipeline systems and is illogical given that the risk of atmospheric corrosion is driven by the operating environment where that asset resides.

The Associations recommend that the risk associated with atmospheric corrosion for distribution pipelines be managed under an operator's DIMP plan. This would enable an operator to use a performance-based and data-driven approach to lengthen the frequency between these inspections when appropriate.

The Associations recommend the following modifications to §192.481 and §192.1007 to reflect a risk-based approach that will result in significant annual resource savings without compromising the safety of the natural gas system. These resources can be re-directed to other risk reduction activities under DIMP.

§192.481 Atmospheric Corrosion Monitoring

(a) Each operator must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

~~If the pipeline is located~~ Pipeline location and type:	Then the frequency of inspection is:
Onshore Transmission	At least once every 3 calendar years, but with intervals not exceeding 39 months
Onshore Distribution	Frequency of inspection shall be specified in the operator's Distribution Integrity Management Plan, as required by §192.1007
Offshore	At least once each calendar year, but with intervals not exceeding 15 months

(b) During inspections the operator must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.

(c) If atmospheric corrosion is found during an inspection, the operator must provide protection against the corrosion as required by §192.479.

§192.1007 What are the required elements of an integrity management plan?

A written integrity management plan must contain procedures for developing and implementing the following elements:

(a) *Knowledge.* An operator must demonstrate an understanding of its gas distribution system developed from reasonably available information.

   (1) Identify the characteristics of the pipeline's design and operations and the environmental factors that are necessary to assess the applicable threats and risks to its gas distribution pipeline.

   (2) Consider the information gained from past design, operations, and maintenance.

   (3) Identify additional information needed and provide a plan for gaining that information over time through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities).

   (4) Develop and implement a process by which the IM program will be reviewed periodically and refined and improved as needed.

   (5) Provide for the capture and retention of data on any new pipeline installed. The data must include, at a minimum, the location where the new pipeline is installed and the material of which it is constructed.

(b) *Identify threats.* The operator must consider the following categories of threats to each gas distribution pipeline: corrosion, natural forces, excavation damage, other outside force damage, material or welds, equipment failure, incorrect operations, and other concerns that could threaten the integrity of its pipeline. An operator must consider reasonably available information to identify existing and potential threats. Sources of data may include, but are not limited to, incident and leak history, corrosion control records **(including atmospheric corrosion records)**, continuing surveillance records, patrolling records, maintenance history, and excavation damage experience.

(c) *Evaluate and rank risk.* An operator must evaluate the risks associated with its distribution pipeline. In this evaluation, the operator must determine the relative importance of each threat and estimate and rank the risks posed to its pipeline. This evaluation must consider each applicable current and potential threat, the likelihood of failure associated with each threat, and the potential consequences of such a failure. An operator may subdivide its pipeline into regions with similar characteristics (e.g., contiguous areas within a distribution pipeline consisting of mains, services and other appurtenances; areas with common materials or environmental factors), and for which similar actions likely would be effective in reducing risk.

(d) *Identify and implement measures to address risks.* Determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline. These measures must include an effective leak management program (unless all leaks are repaired when found).

§192.1015 What must a master meter or small liquefied petroleum gas (LPG) operator do to implement this subpart?

(a) ***General.*** No later than August 2, 2011 the operator of a master meter system or a small LPG operator must develop and implement an IM program that includes a written IM plan as specified in paragraph (b) of this section. The IM program for these pipelines should reflect the relative simplicity of these types of pipelines.

(b) ***Elements.*** A written integrity management plan must address, at a minimum, the following elements:

    (1) ***Knowledge.*** The operator must demonstrate knowledge of its pipeline which, to the extent known, should include the approximate location and material of its pipeline. The operator must identify additional information needed and provide a plan for gaining knowledge over time through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities).

    (2) ***Identify threats.*** The operator must consider, at minimum, the following categories of threats (existing and potential): Corrosion **(including atmospheric corrosion)**, natural forces, excavation damage, other outside force damage, material or weld failure, equipment failure, and incorrect operation.

    (3) ***Rank risks.*** The operator must evaluate the risks to its pipeline and estimate the relative importance of each identified threat.

    (4) ***Identify and implement measures to mitigate risks.*** The operator must determine and implement measures designed to reduce the risks from failure of its pipeline.

    (5) ***Measure performance, monitor results, and evaluate effectiveness.*** The operator must monitor, as a performance measure, the number of leaks eliminated or repaired on its pipeline and their causes.

    (6) ***Periodic evaluation and improvement.*** The operator must determine the appropriate period for conducting IM program evaluations based on the complexity of its pipeline and changes in factors affecting the risk of failure. An operator must re-evaluate its entire program at least every five years. The operator must consider the results of the performance monitoring in these evaluations.

3. Mechanical Fitting Failure Reporting (MFFR)

Recommended Action(s): Eliminate the submission of the Mechanical Fitting Failure Report, as required under Distribution Integrity Management.

CFR Code Sections Impacted: §191.12 and §192.1009

Reason(s):
1. Eliminate the reporting of information which does not lead to pipeline safety improvement actions
2. Partial duplication to efforts of the Plastic Pipe Data Collection initiative

Estimated Cost Savings: Burden reduction for PHMSA due to elimination of information reported to PHMSA and data analysis conducted by PHMSA staff. Minimal savings for operators for time spent submitting information.

Distribution pipeline operators are currently required to submit mechanical fitting failure reports that result in a hazardous leak. The submissions are due by March 15 of the following year and are submitted through an online portal. PHMSA began collecting this information in 2012 and annually receives 10,000-20,000 reports per year. This figure may seem significant; however, there are millions of mechanical fittings in service in the nation's natural gas delivery system. The fittings have been manufactured by dozens of companies and represent a wide range of applications, configurations, and vintages. The Associations understood the initial interest in collecting this type of information, but have concerns about the value of this data being submitted and aggregated at a national level.

The Associations recommend eliminating the reporting requirement for two primary reasons. First, it would be challenging to reach valid conclusions on a specific manufacturer's product's performance, for both type of fitting or vintage of fitting, because the total population of mechanical fittings in service is unknown. Therefore, the failure rate cannot be determined.

Second, plastic material failures, including mechanical fittings, are currently collected through the Plastic Pipe Data Collection initiative (PPDC). The PPDC, composed of representatives from AGA, APGA, Plastics Pipe Institute (PPI), National Association of Regulatory Utility Commissioners (NARUC), National Association of Pipeline Safety Representatives (NAPSR), National Transportation Safety Board (NTSB) and DOT-PHMSA has been coordinating since 1999 and receiving information since 2000 into a database of in-service plastic piping system failures and/or leaks with the objective of identifying possible performance issues. The PPDC meets bi-annually to analyze the data from historical plastic material failures to identify trends and issues related to specific components. PHMSA's collection of MFFR reports are somewhat duplicative to the work being performed by the PPDC.

Importantly, the Associations are *not* advocating for operators to stop collecting information on hazardous leaks or the cause of those leaks. Hazardous leak information should continue to be collected by operators as this information is an important part of DIMP. This would align with the requirement for operators to know their systems and to collect information that enables the operator to perform the risk assessments central to a DIMP plan. The Associations are only suggesting the reporting requirement under §191.12 be eliminated.

The savings to the industry would be equal the avoided time and labor cost of preparing the information to be submitted to PHMSA. There would also be substantial savings in the time that PHMSA staff spends in collecting this information, analyzing the information, and storing the information.

4. Maximum allowable operating pressure: Steel or plastic pipelines

Recommended Action(s): Provide clarity under Part 192 regulations that where an operator of a distribution system has a pressure test record, allow that pressure test to determine the Maximum Allowable Operating Pressure (MAOP) for that distribution pipeline.

Reason(s):

- Where a pressure test record exists, the proposal to verify the MAOP through the design formula as prescribed in §192.619(a)(1) is duplicative and unnecessary for the purposes of validating an MAOP.
- Pressure testing is considered the preferred method for establishing MAOP for distribution operators.

CFR Code Sections Impacted: §192.619

Estimated Cost Savings: Very significant

The Associations recognize that PHMSA's *Safety of Gas Transmission and Gathering Pipelines* rulemaking includes a proposal to modify 49 CFR §192.619. Therefore, this recommended action only focuses on 49 CFR §192.619 as it pertains to distribution pipelines.

49 CFR §192.619 identifies four methods for establishing a pipeline's Maximum Allowable Operating Pressure (MAOP): 1) the design pressure of the weakest element in the segment; 2) pressure testing; 3) the highest actual operating pressure in the five years prior to the segment becoming subject to regulation under Part 192; and 4) the maximum safe pressure considering the history of the segment, particularly known corrosion and the actual operating pressure. Of these four methods, method 2 - pressure testing, is widely regarded by regulators and operators as the preferred method for establishing MAOP for distribution pipelines.

Where distribution operators have a record of a pressure test, PHMSA should be definitive in allowing that pressure test to determine the MAOP for that pipeline. Currently, there is a lack of clarity in the regulations surrounding if additional data is needed when an operator has a pressure test record. This results in an added burden to operators to consider performing additional actions under 49 CFR §192.619, and this burden is more significant when the pipelines are pre-regulation pipelines and there were no regulations in place at that time requiring specific records to be kept.

It should be noted that where a distribution pipeline has a pressure test record, verifying the MAOP through the design formula as prescribed in §192.619(a)(1) is duplicative and unnecessary for the purposes of validating an MAOP for a distribution pipeline.

5. Excess Flow Valves as a Form of Meter Protection

Recommended Action(s): Allow Excess Flow Valves to be considered as a form of meter protection.

Reason(s): Excess Flow Valves have proven to be a mitigative measure to protect from the consequences of vehicular damage but they have not been formally recognized in regulation.

CFR Code Sections Impacted: §192.353(a)

Estimated Savings: Minimal

49 CFR §192.353, **Customer meters and regulators: Location**, requires:

(a) Each meter and service regulator, whether inside or outside a building, must be installed in a readily accessible location and be protected from corrosion and other damage, including, if installed outside a building, vehicular damage that may be anticipated. However, the upstream regulator in a series may be buried.

In many dense urban and suburban areas, it can be impractical to install protective bollards around a meter set due to the lack of yards or the narrow width of sidewalks, alleyways and driveways. In addition, the installation of protective bollards can make those sidewalks, alley ways or driveways unusable. Due to the aesthetics of the bollards, homeowners, business owners and local governments almost universally resist their installation.

Excess flow valves (EFVs) are safety devices installed on natural gas distribution pipelines that restrict the flow of natural gas when that flow exceeds a certain limit, such as when a service line is damaged due to excavation damage, vehicular damage, or other activities. When activated, the EFV can stop the flow of natural gas, limiting the risk of escaping natural gas due to this type of damage or a pipe failure, and providing safety benefits.

EFVs have proven to be an effective form of protection against vehicular damage but they have not been formally recognized in regulation. EFVs can resolve the issues identified above related to the installation of bollards and, from a pipeline safety perspective, an EFV is a better means for protecting the downstream system and general public in a high damage/high gas flow scenario since it would automatically shut off the flow of natural gas[47].

It is recommended that PHMSA modify 49 CFR §192.353(a) as follows in **red**:

> **§192.353 Customer meters and regulators: Location**
> (a) Each meter and service regulator, whether inside or outside a building, must be installed in a readily accessible location and be protected from corrosion and other damage, including, if installed outside a building, vehicular damage that may be anticipated. However, the upstream regulator in a series may be buried. **Some examples of acceptable types of protection would include bollards, curbs, fencing or an excess flow valve.**

C. GENERAL GAS PIPELINE TOPICS

1. Transmission Line Definition

Recommended Action(s): Change the definition of a "Transmission line" to:

- Revise the percent SMYS threshold within the Transmission Line definition
- Add a criterion within the Transmission Line definition that allows operators to voluntary designate a pipeline as transmission

Reason(s):

- The percent SMYS threshold in the existing Transmission line definition is outdated and incorrect.
- Pipelines that operate less than 30% SMYS are prone to fail by leakage rather than rupture and pose less risk than those that operate greater than 30% SMYS
- Pipeline safety regulations in Part 192 already imply that low stress transmission pipelines pose reduced risks to the public
- There is significant confusion and different interpretations of what is a transmission pipeline

CFR Code Sections Impacted: §192.3

Estimated Cost Savings: Significant

The Associations request PHMSA consider the following changes to the definition of "*Transmission line*" within §192.3 as part of the regulatory review. These comments mirror those submitted by the Associations in response to the Safety of Gas Transmission and Gathering Lines Notice of Proposed Rulemaking. In that proposed rule, PHMSA suggested a modification to the *Transmission Line* definition.

[47] The Associations recognize that damages resulting from vehicular impact vary widely, based upon vehicular speed and intensity of the collision. Operators would need to use judgement in deciding when to install an EFV, bollard, curb or other means of meter protection.

These comments are not intended to supersede those comments, but instead should be reviewed in tandem.

The Associations recommend the following actions be taken:

- Revise the percent SMYS threshold within the *Transmission Line* definition
- Add a criterion within the *Transmission Line* definition that allows operators to voluntary designate a pipeline as transmission.

Redefine the Threshold for Percent SMYS in the Transmission Line Definition

The Associations believe the percent SMYS threshold in the existing *Transmission line* definition is outdated and incorrect. There is a long-documented history demonstrating and explaining why pipelines that operate less than 30% SMYS pose less risk than those that operate greater than 30% SMYS. Pipelines that operate less than 30% SMYS are prone to fail by leakage rather than rupture. This understanding is so widely accepted that Congress enacted specific mandates to pipelines that operate greater than 30% SMYS.[48] It is additionally supported by the Kiefner/GTI Report "Leak vs. Rupture Thresholds for Material and Construction Anomalies," which pointed out that "no evidence was found that a propagating ductile rupture could arise from an incident attributable to any one of these causes in a pipeline that is being operated at a hoop stress level of 30% of SMYS or less." This distinction is also supported by PHMSA in the preamble of the Gas Transmission and Gathering Lines Proposed Rule[49].

Additionally, the gas pipeline industry, through the Gas Transmission Institute (GTI) and Battelle, undertook an effort to provide additional technical justification for establishing the threshold for low and high stress pipelines at 30% SMYS. GTI reviewed numerous previous studies and analyses on the issue and compared them to current failure models and previous incidents. The results of this effort are presented in the third GTI report.[50] The key findings of the effort are:

1. In regards to corrosion defects, the transition from a leak to a rupture ranges from 30% SMYS to 35% SMYS.
2. In regards to mechanical defects, ruptures can and have occurred on pipelines operating below 30% SMYS, but are unlikely because of the combination of the following factors that need to be present:
    a. Defects must be long in length;
    b. Defects must run axially along the pipe;
    c. Defects must penetrate between 80% - 90% of the wall thickness, and
    d. Pipe must have low toughness
3. In regards to mechanical defects, a conservative analysis of the OPS incident database records indicates that some ruptures have occurred at stress levels below 30% SMYS. The database does not indicate whether the failure was immediate or delayed.

[48] Pipeline Safety Act of 2011. Section 23(d).
[49] 81 Fed.Reg. 20813.
[50] "Leak vs. Rupture Considerations for Steel Low Stress Natural Gas Transmission Pipelines," prepared by Battelle, GTI Report GRI-00/0232.

4. For both corrosion and mechanical defects, given a specific operating stress level, whether a pipe leaks or ruptures upon failure, depends on defect size, defect orientation, pipe geometry (size, diameter, etc.) and pipe toughness.

Furthermore, Pipeline safety regulations in Part 192 already imply that low stress transmission pipelines pose reduced risks to the public. Stress levels below 20%, 30%, or 40% SMYS are recognized in at least 11 sections of Part 192 as low stress pipelines, and consequently are subjected to less stringent requirements. These 11 sections of Part 192 primarily address welding, pipe repair, strength/leak testing, and uprating of pipelines.

The Associations propose that 30% SMYS be utilized as the demarcation pressure for the second criterion in the *Transmission line* definition. The 30% SMYS threshold better reflects current understanding of the appropriate stress level for the leak/rupture threshold.

Allow Operators to Designate a Pipeline as Transmission

If PHMSA adopts the Associations' recommendations outlined above, it is also essential that operators be allowed to voluntarily designate pipeline laterals or other segments as transmission. This is necessary so that operators who have managed a system in accordance with the transmission regulatory framework can continue to do so.

The Associations propose the following definition for *Transmission line.*

Proposed Changes to **§ 192.3 "Definitions"**:

> *Transmission line* means a pipeline, other than a gathering line, that:
>
> (1) Transports gas from a gathering line or storage facility to a distribution center, storage facility; or large volume customer that is not down-stream from a distribution center;
> (2) operates at a hoop stress of ~~20~~ **30** percent or more of SMYS;
> **(3)** transports gas within a storage field**; or**
> **(4)** **is voluntarily determined by the operator to be a transmission pipeline.**
> Note: A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas.

2. Definition of an Incident

Recommended Action(s): Raise the incident reporting requirements to $100,000; and remove the requirement for operators to submit “Fire First” incidents in the Incident Reporting Instructions.

Reason(s):

1. The $50,000 or property damage threshold was established in 1984. Operators are required to submit all incidents that meet the $50,000 threshold in 2017 dollars but PHMSA only displays Significant Incidents that meet the criteria of $50,000 in 1984 dollars.
2. Gas distribution incidents caused by a nearby fire or explosion (known as “Fire First” incidents) are not due to a pipeline safety issue and therefore should not be reported.

CFR Code Sections Impacted: §191.3

Estimated Cost Savings: Approximately 3,000 hours per year savings for industry. Additional savings to government due to a reduction in the number of reports submitted, analysis of these reports, and storage of additional reports.

Incident reporting is critical for operators, regulators and the public, as it represents a universal performance metric for the nation’s pipeline system. It also helps justify new regulations that can further enhance pipeline safety.

In 1984, when the requirement for incident reporting on pipelines was originally promulgated, PHMSA’s process set the criteria for when an operator must submit an incident report. One criterion was property damage and a threshold was set at $50,000. In 2017, pipeline operators are still required to submit a report for incidents that meet the $50,000 property damage criterion. Accounting for inflation, the $50,000 threshold in 1984 is now equivalent to approximately $119,000 in 2017. Industry understands that PHMSA removes from its database those incidents that are estimated below $50,000 in 1984-dollars; however, operators are still required to submit reports on these incidents to PHMSA.

Industry recommends that PHMSA reduce the regulatory burden on operators by increasing the property damage criterion for required incident reporting to $100,000. For consistency, it is recommended that PHMSA continue to display only Significant Incidents that meet the $50,000 in 1984-dollar threshold.

In addition, gas distribution incidents that are caused by a nearby fire or explosion impacting the pipeline system (also known as “Fire First” incidents) are still required to be reported by PHMSA if they result in a death or injury. PHMSA has excluded these events from the serious and significant incident data sets since March 2004 because they are not the result of a pipeline safety issue. Therefore, operators should no longer be required to report these Fire First events as incidents.

It should be noted that operators submitted over 500 incidents from 2010 to 2016 that were subsequently removed by PHMSA for failure to meet the $50,000 in 1984 criteria, were “Fire First” incidents, or for other reasons. Assuming that the burden to complete each incident report is approximately 6 hours, this results in an average savings of over 3,000 hours per year. Making the above changes to the incident reporting criteria will not only reduce burdens on the industry but it will also the burden to government due to less data review and analysis, fewer calls to operators, and reduced data storage requirements.

The Associations suggest the following change for **49 CFR §191.3:**

Incident means any of the following events:

(1) An event that involves a release of gas from a pipeline, gas from an underground natural gas storage facility, liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences:

(i) A death, or personal injury necessitating in-patient hospitalization;

(ii) Estimated property damage of **~~$50,000~~ $100,000** or more, including loss to the operator and others, or both, but excluding cost of gas lost; or

(iii) Unintentional estimated gas loss of three million cubic feet or more.

(2) An event that results in an emergency shutdown of an LNG facility or an underground natural gas storage facility. Activation of an emergency shutdown system for reasons other than an actual emergency does not constitute an incident.

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

III. ADDITIONAL COMMENTS: PHMSA ACTIONS UNDERWAY

In addition to the Associations' primary regulatory review recommendations, the Associations have provided the following comments regarding some topics that PHMSA is currently reviewing.

1. Gas Gathering Regulations

Recommended Action(s):

- Extend PHMSA's incident reporting requirements and a limited version of its annual reporting requirements to operators of Class 1 gathering lines;
- Defer further action on PHMSA's proposed changes to the gathering line regulations until additional safety-related data is collected and analyzed; and
- Develop a new API recommended practice with appropriate, risk-based safety standards for onshore gas gathering lines.

Reason(s): Industry understands and supports the need to collect additional safety-related data for gas gathering lines, including for historically-exempt rural gathering lines in Class 1 locations, to validate the industry's strong historical safety record. In addition, API is developing a new recommended practice for risk-based safety standards for onshore gas gathering lines. The standards development process will involve NAPSR, PHMSA, and other interested stakeholders.

CFR Code Sections Impacted: 49 C.F.R. Part 192

Estimated Savings to Industry: A third-party economic analysis showed PHMSA's gas gathering proposals would cost gathering line operators more than $28B over the initial 15-year compliance period, and the economic impact on small gathering companies would be devastating, imposing compliance costs equivalent to approximately 90% of annual revenue.

Effected Entities: Gas Gathering Operators

The NPRM issued by PHMSA in April 2016 would make significant changes to the federal regulations for onshore gas gathering lines. The proposed rule would establish a new definition of an onshore gas gathering line; extend certain requirements in 49 C.F.R. Part 192 to gas gathering lines in Class 1 locations; modify the requirements that apply to currently regulated gas gathering lines in Class 2, 3, and 4 locations; and require operators of all gathering lines (whether regulated or not) to comply with the reporting requirements in 49 C.F.R. Part 191. As currently drafted, the proposed rule dramatically expands the breadth of pipeline regulation under Part 192 in an overbroad and imprecise manner resulting in costly, undue burdens upon the regulated community. Further, PHMSA has not completed the congressionally-mandated existing gathering lines regulation review, which should form the risk-based support for any new federal requirements. Although rural gathering lines in Class 1 locations have never presented the kind of risk that warranted regulation at the federal level, the Associations realize that the safety of gas gathering lines needs to be evaluated based on current information, and that recent changes in the oil and gas industry (such as higher pressure, larger diameter piping) require further validation of the industry's strong historical safety record. Industry stands ready to assist PHMSA in collecting data to justify any appropriate regulations. However, in conjunction with this work, any additional requirements that were proposed in the 2016 NPRM need to be removed. Also, in coordination with data collection, API has begun the steps to publish a new recommended practice detailing risk-based safety standards for onshore gas gathering lines. API has a long and very successful history of developing safety standards for the oil and gas industry, and nearly a dozen API recommended practices, specifications, and standards are currently incorporated by reference into the federal gas pipeline safety regulations. Plus, the open, transparent standards development process allows for the participation of NAPSR, PHMSA, and other interested stakeholders. Through these steps, a new recommended practice can be developed that contains appropriate, risk-based regime safety standards for onshore gas gathering lines, including the new generation of unconventional gathering lines that are being installed and operated in the nation's shale plays.

2. Underground Natural Gas Storage

Recommended Action(s):

- Provide for reasonable time frames for operators to implement API RP 1170 and 1171;
- Incorporate by reference API RP 1170 and 1171 without modification of non-mandatory provisions;
- Incorporate underground natural gas storage facilities into a new "Part" within Subchapter D of PHMSA's regulations, separate from Part 192.

Reason(s): As currently drafted, the Underground Gas Storage Facility Interim Final Rule makes all non-mandatory provisions in the Recommended Practices mandatory requirements, and may require operators to implement all of these requirements within one year. This changes the original intent of the Recommended Practices and creates an ambiguous and impracticable regulation.

CFR Code Sections Impacted: §192.7 and §192.12

Estimated Savings to Industry: Significant

Effected Entities: Underground Natural Gas Storage Facility Operators

The Associations have publicly supported PHMSA's incorporation by reference of API Recommended Practices 1170 & 1171 ("RPs") as federal regulations for underground natural gas storage ("UGS") facilities, and fully supported their members in adopting the RPs in advance of any federal regulation on UGS facilities. The RPs recognize and address the diversity of UGS facilities nationwide and appropriately serve as nationwide standards for UGS functional integrity. Nonetheless, PHMSA must revise certain aspects of its Underground Gas Storage Facility Interim Final Rule to ensure a practicable and effective final rule for underground natural gas storage facilities, as outlined in the Associations' February 2017 public comments.[51] PHMSA is currently considering the Associations' petition and accepting additional public comment as the agency develops a final rule.[52]

The Associations' specific recommendations include:

- Incorporate by reference API RP 1170 and 1171 *without modification* of <u>non-mandatory provisions</u>.
    - The significant number of mandatory provisions ("shalls") in the RPs ensure safe and effective integrity management programs for all underground gas storage facilities by imposing broad obligations on operators of underground natural gas storage facilities. These overarching mandatory provisions require operators to develop detailed systems to manage the different aspects of functional integrity management programs.
    - PHMSA's requirement that all non-mandatory provisions become mandatory has resulted in a regulation that is not practicable and is unreasonable. Furthermore, the procedure for obtaining a variance from the Recommended Practices is unworkable and a departure from PHMSA's past position.
- Provide for *reasonable implementation periods* in the final rule, consistent with PHMSA's April 2017 FAQs: https://primis.phmsa.dot.gov/ung/faqs.htm
- Incorporate underground gas storage facility regulations into a new Part within Subchapter D of PHMSA's regulations, to ensure clarity with respect to current and future regulatory requirements for underground natural gas storage facilities

[51] Pipeline Safety: Safety of Underground Natural Gas Storage Facility Interim Final rule; Comments of AGA, APGA, API, and INGAA (Feb. 17, 2017). http://www.ingaa.org/Filings/RegulatoryFilings/31871.aspx.
[52] Pipeline Safety: Safety of Underground Natural Gas Storage Facilities Interim Final Rule; reopening comment period, 82 Fed. Reg. 48,655 (Oct. 19, 2017).

3. Post construction Inspections

Recommended Action(s): Bring together a Construction Inspection Advisory Group to move forward inspection requirements pertaining to the construction of transmission lines and distribution mains, with a focus on pressure containing assets where an error in construction would create an immediate impact to integrity and where it is only during the construction process that the inspection could take place.

Reason(s): It is necessary to address the concerns voiced by state pipeline safety inspectors and industry with respect to §192.305, including the significant burden on smaller operators, the confusion around the inspection of work done by contractors, and the portions of 49 CFR Part 192 applicable to the regulation.

CFR Code Sections Impacted: §192.305

Estimated Savings to Industry: Will depend on the outcome of the work of the Advisory Group.

In March 2015, PHMSA issued its Miscellaneous Final Rule that contained 17 different amendments to pipeline safety regulations.[53] One of these regulatory changes pertained to the performance of post-construction inspections (49 CFR §192.305 – Inspection General). AGA, APGA and the National Association of Pipeline Safety Representatives (NAPSR) all filed petitions to PHMSA to reconsider this final rule. Based on these petitions, PHMSA delayed the effective date of the amendment to 49 CFR 192.305 indefinitely.

As published in the final rule the new construction inspection regulation reads:
Each transmission line and main must be inspected to ensure that it is constructed in accordance with this subpart. An operator must not use operator personnel to perform a required inspection if the operator personnel performed the construction task requiring inspection. Nothing in this section prohibits the operator from inspecting construction tasks with operator personnel who are involved in other construction tasks.

The primary concerns voiced in the petitions for reconsideration included:

- the significant burden to smaller operators who may only have one qualified crew to work on distribution mains and predominantly utilize two-man crews;
- the short timeframe to comply with the changes;
- confusion surrounding the inspection of work done by contractors, and
- the fact that the final rule only applies to one subpart of 49 CFR Part 192.

Prior to taking further action, the Associations encourage PHMSA to bring together a Construction Inspection Advisory Group made up of key stakeholders to resolve the issues voiced by AGA, APGA, and

[53] Pipeline Safety: Miscellaneous Changes to Pipeline Safety Regulations, 80 Fed. Reg. 12,762 (Mar. 11, 2015).

NAPSR. The scope of the effort should address only the inspection requirements pertaining to the construction of transmission lines and mains, with a focus on pressure containing assets where an error in construction would create an immediate impact to integrity and where it is only during the construction process that the inspection could take place. The Advisory Group can assist PHMSA in determining a risk-based approach that meets the intent in the original regulation, but in a manner that does not result in an unnecessarily burdensome impact to operators or contractors.

4. PHMSA Should Require Pressure Vessels to be Tested to 1.3 times the Maximum Allowable Working Pressure (MAWP)

Recommended Action(s):

- Rescind § 192.153(e) and the related modifications to § 192.165(b)(3) and continue to require a 1.3 times MAWP test for all pressure vessels (existing and new)
- Alternatively, if PHMSA decides to retain §§ 192.153(e) and 192.165(b)(3), then the requirement to test to 1.5 times MAOP should only apply prospectively. Additionally, the agency should conduct a study validating that a 1.5 times MAOP test factor for pressure vessels is indeed necessary and technically superior than the 1.3 times MAWP test factor.

Reason(s): Pressure testing requirements for existing and new vessels should be consistent with the ASME Boiler and Pressure Vessel Code ("BPVC"), which requires 1.3 x MAWP. The ASME BPVC is recognized and accepted as the standard of safety by many government agencies worldwide. There is no correlation between the MAWP of a vessel and the MAOP of a pipeline. It is not recommended that operators retest pressure vessels after the manufacturer has already tested and certified the component.

CFR Code Sections Impacted: §192.153 and §192.165

Estimated Cost Savings: Significant

Effected Entities: Natural Gas Transmission, Distribution and Regulated Gathering Operators

PHMSA is evaluating its existing regulations governing the required test pressure for components fabricated by welding (§ 192.153). Such components are generally referred to as "pressure vessels."

As part of a 2015 rulemaking[54], PHMSA made modifications to §§ 192.153 & 192.165 to change the acceptable test factor for a pressure vessel built under the ASME Boiler and Pressure Vessel Code ("BPVC") from the ASME requirement of 1.3 times Maximum Allowable Working Pressure ("MAWP") to 1.5 times the MAOP. Prior to that change, § 192.153 required operators to design, construct, and *test* components fabricated by welding in accordance with the 2007 version of Section VIII of the ASME Boiler BPVC. Since the BPVC uses a test factor of 1.3 times MAWP, not 1.5 times MAOP, an operator that purchased an ASME pressure vessel prior to the effective date of the Final Rule was required to test it to a minimum of 1.3

[54] *Ibid.*

times MAWP. Following INGAA's petition for reconsideration[55], PHMSA's Associate Administrator, Office of Pipeline Safety sent INGAA a letter indicating that PHMSA would stay enforcement of this requirement for vessels put into operation between July 14, 2004 and October 1, 2015, pending a technical study of the matter. This study has not yet been published.

PHMSA should rescind § 192.153(e) and the related modifications to § 192.165(b)(3) and continue to allow a 1.3 x MAWP test for all pressure vessels (existing and new). Pressure testing requirements for existing and new vessels should be consistent with the ASME BPVC, which requires 1.3 x MAWP. *The ASME BPVC is recognized and accepted as the standard of safety by many government agencies worldwide.* Pressure vessels designed, constructed and tested under the ASME BPVC are utilized in a variety of industries around the world, including: gas processing, petroleum refining, chemical and petrochemical manufacturing, power plants, military industrial complex, industrial boilers, pulp and paper manufacturing, food processing, aviation railroad and highways, among other. In the United States, this includes the Occupational Safety and Health Administration, the Bureau of Safety and Environmental Enforcement, the Department of Energy, and the Department of Defense. *PHMSA has not demonstrated why the 2007 BPVC (incorporated in Part 192) is insufficient.* In making this regulatory change that adopts a different testing standard than the ASME BPVC, PHMSA is breaking with a long-standing practice that has existed since 1968.

There is a basic difference between pipe and pipeline components. Pipe is designed using the Barlow formula to compute a design pressure based on SMYS. By comparison, pipeline components are "rated" by the manufacturer. The different design bases cannot be interchanged as PHMSA has done in § 192.153(e). There is no correlation between the MAWP of a vessel and the MAOP of a pipeline. PHMSA states in the preamble to its 2015 rule that ASME pressure vessels are subject to the additional testing requirements listed in § 192.505(b). This is incorrect. § 192.505(b) requires compressor, regulator and measuring stations to be tested to Class 3 location requirements. These requirements are derived from a provision in section 843.5 of the USAS B31.8-1968 that applied to the testing of gas ***piping*** at compressor stations. Section 804.3 of USAS B31.8-1968 states that the code does not apply to design and fabrication of pressure vessels covered by BPVC.

Any new pressure testing standards should only apply prospectively. It is inappropriate for PHMSA to retroactively require existing vessels to be pressure tested to a higher pressure than was required by the version of the BPVC at the time of manufacturing. *It is not recommended that operators retest pressure vessels after the manufacturer has already tested and certified the component.* If required to retest pressure vessels that are currently in use, operators could risk invalidating their warranty and insurability of these components. Re-testing the vessel to a test factor other than 1.3 times MAWP and utilizing a test process not approved by ASME could invalidate the ASME certification for the vessel.

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[55] Petition for Reconsideration Filed by The Interstate Natural Gas Association of America, Docket No. PHMSA-2010-0026 (Apr. 10, 2015).

IV. CONCLUSION

The Associations are pleased to respectfully share these suggestions for PHMSA's consideration in response to the Notification of Regulatory Review. The changes to existing regulations recommended by the Associations will enable operators to reallocate resources to activities and programs that would benefit system integrity and public safety for the American communities that enjoy the benefits of natural gas , including to activities that may be required by proposed new regulations.

The Associations believe the suggested modifications will not compromise safety. Some recommendations will instead result in additional flexibility for operators to deploy resources to support programs and initiatives in a more efficient manner. Other recommendations will result in time savings for operator staff and PHMSA staff. The Associations are committed to providing additional information for any of these recommendations, if desired.

Respectfully submitted,

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APPENDIX

Pipeline Safety: Operator Qualification, Cost Recovery, Accident and Incident Notification, and Other Pipeline Safety Changes Final Rule

September 18, 2017

In February 2017, the Pipeline and Hazardous Materials Safety Administration (PHMSA) released the Operator Qualification, Cost Recovery, & Other Pipeline Safety Changes Final Rule,[1] which went into effect on March 24, 2017.

The rule included new provisions that require operators to periodically inspect every "service line directly connected to a production, gathering, or transmission pipeline that is not operated as part of a distribution system," commonly known throughout industry as "Farm Taps." Furthermore, PHMSA amended Part 192 regulations so that operators could no longer cover Farm Taps under their Distribution Integrity Management Program (DIMP)[2].

PHMSA published its Preliminary Regulatory Impact Assessment (PRIA)[3] for the rule in February 2017. The American Gas Association (AGA)[4] believes that PHMSA significantly underestimated the costs associated with the new Farm Tap inspection requirements. In Section 6.2.5 of the PRIA, PHMSA states that removal of Farm Taps from DIMP will result in a net savings to industry because the new inspection requirements under §192.740 are less stringent than those that might be developed as part of an operator's DIMP plan. This conclusion may be accurate if PHMSA were only considering the impact to transmission operators that do not manage distribution assets. In that specific case, a pure transmission company would have the burden of developing, implementing, revising and managing a DIMP plan that was specifically created for Farm Taps. For operators that manage both distribution and transmission pipeline systems, AGA respectfully disagrees with the assertion that the new inspection requirements are less stringent and will result in a savings to industry. For operators that manage both transmission and distribution assets, Farm Taps have always been included in the operator's DIMP plan. The risks associated with Farm Taps have been risk ranked and the appropriate mitigation measures to reduce identified risks have been taken. With the new rulemaking, Farm Taps must now be removed from DIMP plans, plans must be redone to reevaluate and rank remaining risks, and new non-risk based prescriptive actions must be performed. In addition, in a recently conducted survey of membership, many AGA members cited a need for extensive front-end investment to rebuild Farm Taps to make them capable of inspection per the new requirements in §192.740. Table 1 shown below shows the annual cost increases that will occur for three AGA members with a high number of Farm Taps in their system:

Table 1: Sample Annual Costs for Addressing Farm Taps

Participant	AGA Member Cost for inclusion of Farm Taps in DIMP plan (Annual)	AGA Member Cost for §192.740 Inspection (Annual)
AGA Member #1	$5,600	$2,100,000
AGA Member #2	$10,500	$1,700,000
AGA Member #3	$205,000	$1,620,000

AGA's entire membership was surveyed for this data and 16 replies were received. These responses account for 79,354 Farm Taps. It is important to recognize that Farm Tap inventory varies greatly in volume and asset condition from

[1] 49 C.F.R §192.740 2017

[2] 49 C.F.R §192.1003 2017

[3] PHMSA PRIA 2013-0163

[4] The American Gas Association, founded in 1918, represents more than 200 local energy companies that deliver clean natural gas throughout the United States. There are more than 72 million residential, commercial and industrial natural gas customers in the U.S., of which 94 percent — over 68 million customers — receive their gas from AGA members. Today, natural gas meets more than one-fourth of the United States' energy needs.

operator to operator. Total costs over the next three years, as well as weighted average costs required to maintain each Farm Tap as a part of DIMP and §192.740, are shown in Table 2 below for those 16 operators:

Table 2: Estimated AGA Member Survey Respondent Costs

	AGA Member Cost for inclusion of Farm Taps in DIMP plan	AGA Member Cost for §192.740 Inspection
Total Costs (2017-2020)	$6,239,172	$128,949,549
Costs Per Farm Tap	$78.62	$1,625

Furthermore, AGA questions the pipeline safety enhancements attributed to new regulatory requirement. Operators have continuously monitored Farm Taps for heightened levels of risk under their DIMP plan since 2011 when the rule was promulgated. AGA reminds PHMSA that operators currently are obligated to periodically perform leak surveys on these assets under §192.723(b)(2). This provides operators an opportunity to verify their functionality and identify any existing abnormal operating conditions.

An overwhelming majority of AGA operators have not identified any elevated risk associated with the devices through their DIMP risk identification processes. PHMSA stated in its PRIA that risk introduced by Farm Taps to the public is "generally low." Furthermore, PHMSA did not cite any pipeline incident in either the rule or PRIA that might warrant the new inspection requirements. According to PHMSA's Pipeline Incident Flagged Files,[5] only three incidents directly involving Farm Taps have been explicitly identified on a PHMSA Gas Distribution System Incident Report[6] since 2010. All three of these incidents were the result of vehicle collisions and not a lack of maintenance or inspection by operators. Due to the apparent infrequent occurrence of pipeline incidents involving Farm Taps, AGA believes that resources would be better spent elsewhere to improve pipeline safety.

President Trump signed an executive order on January 30, 2017 titled "Reducing Regulation and Controlling Regulatory Costs."[7] Section 2(b) requires PHMSA to ensure that the "Total incremental cost of all new regulations, including repealed regulations, to be finalized this year shall be no greater than zero." AGA encourages PHMSA to consider revising §192.740 and §192.1003 to give operators the choice of managing the risk to Farm Taps under either of these regulatory sections. This action would provide industry with the aforementioned mandated cost savings while simultaneously improving pipeline safety by allowing operators to mitigate any future risk associated with Farm Taps through their DIMP program. Finally, it would provide PHMSA with flexibility when considering the incremental costs of new future regulations.

[5] PHMSA Pipeline Incident Flagged Files- Gas Distribution (2010 – Present)

[6] *"Farm Tap Meter/Regulator set" chosen for Field 2 of "Part C – Additional Facility Information" section of PHMSA Gas Distribution Incident Report*

[7] 3 C.F.R. (2017). Reducing Regulation and Controlling Regulatory Cost