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

Pipeline Safety: Meeting of Gas Pipeline Safety Advisory Committee	Docket Nos. PHMSA-2016-0136, PHMSA-2011-0023

COMMENTS ON PHMSA GAS PIPELINE ADVISORY COMMITTEE (GPAC) TELECONFERENCE HELD MARCH 2, 2018

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

March 9, 2018

Contents

I. Introduction

The American Gas Association (AGA)[1], American Petroleum Institute (API)[2], American Public Gas Association (APGA)[3] and Interstate Natural Gas Association of America (INGAA)[4] (jointly "the Associations") submit these comments for consideration by the Pipeline and Hazardous Materials Safety Administration (PHMSA) concerning the fourth Gas Pipeline Advisory Committee (GPAC) meeting on the Safety of Gas Transmission & Gathering Lines Rulemaking (Proposed Rule)[5] that occurred via teleconference on March 2, 2018.[6] The GPAC meetings provide the GPAC Members, PHMSA representatives, the regulated community, and the public the opportunity to discuss topics contained within the Proposed Rule.

The Associations also provided PHMSA and the GPAC members with comments following the previous three GPAC meetings on this rulemaking[7] that were intended to summarize the views expressed during the meetings and elaborate on the concerns identified. Additionally, the Associations provided markups to the proposed regulatory text that were intended to mirror the votes and discussions held by the GPAC and to identify outstanding concerns. The following comments on the March 2, 2018 GPAC teleconference are similar in content and structure.

---

[1] 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.

[2] 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.

[3] APGA is the national, non-profit association of publicly-owned natural gas distribution systems. APGA was formed in 1961 as a non-profit, non-partisan organization, and currently has over 700 members in 37 states. Overall, there are nearly 1,000 municipally-owned systems in the U.S. serving more than five million customers. Publicly-owned gas systems are not-for-profit retail distribution entities that are owned by, and accountable to, the citizens they serve. They include municipal gas distribution systems, public utility districts, county districts, and other public agencies that have natural gas distribution facilities.

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

[5] Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, 81 Fed. Reg. 29830 (May 13, 2016).

[6] Pipeline Safety: Meeting of the Gas Pipeline Safety Advisory Committee, 83 Fed. Reg. 6087 (February 12, 2018). The GPAC is a peer review committee charged with providing recommendations on the technical feasibility, reasonableness, cost-effectiveness, and practicability of PHMSA's proposed safety standards for gas pipeline facilities. 49 U.S.C. §§ 60102(b)(2)(G), 60115.

[7] Pipeline Safety: Meeting of the Gas Pipeline Safety Advisory Committee, 81 Fed. Reg. 83795 (November 22, 2016), held January 11-12 2017, Pipeline Safety: Meeting of the Gas Pipeline Safety Advisory Committee, 82 Fed. Reg. 23714 (May 23, 2017), held June 6-7 2017, and Pipeline Safety: Meeting of the Gas Pipeline Safety Advisory Committee, 82 Fed. Reg. 51760 (November 7, 2017), held December 14-15 2018.

Due to the short timeframe between the March 2, 2018 teleconference and the GPAC's next meeting on March 26-28, 2018 the Associations are providing feedback on specific topics that warrant further discussion during the March 26-28, 2018 meeting. Following the March 26-28, 2018 meeting, the Associations intend to provide comprehensive comments addressing all topics discussed during March meetings. Also, the GPAC discussions clearly articulated that proposals pertaining to gathering lines must be addressed in a separate, dedicated GPAC meeting, and that the issues, commentary and related votes during the March 2, 2018 teleconference did not pertain to, or impact, gathering lines.

The Associations hope that these comments will assist PHMSA, the GPAC members, and the public in having substantive and productive conversations with the goal of developing a final rule that advances pipeline safety.

II. Anomaly Response and Repair Criteria

A. General Comments

The GPAC spent several hours on March 2, 2018 discussing various important issues related to PHMSA's proposed anomaly response and repair requirements for transmission lines. Rather than review the entirety of those discussions, the Associations highlight four key issues that PHMSA should consider in advance of the March 26-28, 2018 GPAC meeting based on the March 2, 2018 discussion:

1) Applying "traceable, verifiable and complete" (TVC) requirements for records used in anomaly response calculations is unnecessary and confusing – this requirement was developed for maximum allowable operating pressure (MAOP) records, not for material property records used in anomaly response calculations. Where material property records are unavailable, PHMSA should allow operators to use the proposed Material Verification process (§192.607), records from comparable pipe as appropriate, or PHMSA's conservative values.
2) PHMSA should introduce a mechanism that allows operators to use engineering analysis to determine whether a response is needed for an indication of a dent with metal loss or metal loss preferentially affecting the long seam.
3) PHMSA should clarify the terminology used in §192.713 and §192.933 and that the timelines prescribed are for the operator's response, not remediation.
4) PHMSA should make specific modifications to align the anomaly response conditions with consensus technical standards and current technologies.

1) Applying "traceable, verifiable and complete" (TVC) requirements for records used in anomaly response calculations is unnecessary and confusing – this requirement was developed for MAOP records, not for material property records used in anomaly response calculations. Where material property records are unavailable, PHMSA should allow operators to use the proposed Material Verification process (§192.607), records from comparable pipe as appropriate, or PHMSA's conservative values.

PHMSA proposes to require that "pipe and material properties used in remaining strength calculations must be documented in traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in remaining strength calculations must be based on properties determined and documented in accordance with §192.607." The Associations agree that selection of appropriate material data properties is critical to ensuring appropriate anomaly response and repair calculations. However, the "traceable, verifiable and complete" (TVC) requirement has historically been applied to MAOP records. Applying this established standard to anomaly response calculations, which represent a much broader set of pipeline maintenance and integrity management activities, is unnecessary and confusing.

Both the National Transportation Safety Board (NTSB) and PHMSA have previously applied the "TVC" requirement when specifically addressing MAOP records. NTSB introduced TVC in recommendations to PG&E following its failure in San Bruno, CA; these recommendations were specific to MAOP reconfirmation.[8] Furthermore, in comments to the Gas Transmission NPRM docket, NTSB refers to the need for TVC records only in the context of MAOP records. NTSB states that "PHMSA has determined that additional rules are needed to ensure that [the] records used to establish MAOP are reliable, traceable, verifiable, and complete.[9]" Similarly, PHMSA's two advisory bulletins addressing records reviews only refer to TVC in the context of MAOP records[10,11] and the records review requirements outlined in Section 23 of the 2011 Act are focused on MAOP.[12] PHMSA fails to demonstrate that the records and data that operators are currently using for anomaly response and repair calculations are insufficient, and PHMSA has not offered evidence of specific problems with the material property records and data operators currently use in anomaly response or repair calculations.

PHMSA should not apply the TVC requirement for records used in anomaly response calculations, as this will create confusion regarding which existing records can be used to support anomaly response calculations and prioritization prior to in-field examination. As discussed at length below, there is an important difference between actions that operators take when evaluating the results of integrity assessments (anomaly response) versus those actions that operators take following in-field examination of potential anomalies (anomaly repair). Requiring operators to undergo the full material verification (§192.607) process to determine the appropriate response is not practical. Conducting destructive or non-destructive testing to verify material properties may require pipeline excavation, which may not be appropriate for making timely anomaly response decisions based on inline inspection. For anomalies requiring excavation, material properties can be verified when the pipeline is exposed.

In the event material property records are not available, operators should be able to leverage data from comparable pipe with known properties, or use the material verification process outlined in §192.607 (as approved by the GPAC at its December 2017 meeting), or use the conservative values offered by PHMSA. Operators currently utilize conservative values that are based upon sound and supported engineering judgements if material data records are unavailable.

---

[8] NTSB, Safety Recommendation to Mr. Christopher Johns, President, Pacific Gas and Electric Co., P-10-2, P-10-3 (Jan. 3, 2011), http://www.ntsb.gov/safety/safety-recs/recletters/P-10-002-004.pdf.

[9] Letter from Christopher Hart, Chairman, NTSB to U.S. Dep't of Transportation at 6, Docket No. PHMSA 2011- 0023 (June 6, 2016), https://www.regulations.gov/#!documentDetail;D=PHMSA-2011-0023-0148.

[10] Pipeline Safety: Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation, 76 Fed. Reg. 1504 (Jan. 10, 2011).

[11] Pipeline Safety: Verification of Records, 77 Fed. Reg. 26822 (May 7, 2012).

[12] 49 U.S.C. § 60139.

The Associations also remind PHMSA of the discussion at the December 2017 GPAC meeting around the importance of PHMSA providing appropriate conservative Charpy toughness values.[13] PHMSA's proposed values (5.0 ft-lb for body toughness and 1.0 ft-lb for seam toughness) are inappropriately conservative. Per "Structural Integrity Associates, Statistical Evaluation of Charpy Toughness Levels for Gas Transmission Pipelines, Report No. 1600513.401, July 2016," PHMSA should allow operators to use 13.0 ft-lb for body toughness and 4.0 ft-lb for seam toughness, when toughness data is not available.

The Associations propose that the required material properties for volumetric anomaly response calculations are grade, diameter, and wall thickness. Similarly, for planar anomalies, including crack features, the required material properties for anomaly response calculations are grade, diameter, wall thickness, and toughness.

2) PHMSA should introduce a mechanism that allows operators to use engineering analysis prior to responding to dents with metal loss and metal loss preferentially affecting the long seam to demonstrate that an indicated anomaly does not pose a risk to pipeline integrity.

In the proposed rule, PHMSA would allow operators to perform an engineering analysis to differentiate metal loss and cracking conditions that require a response (proposed §192.713(d)(1)(i) and §192.933(d)(1)(i) and PHMSA "alternative cracking criterion"), but does not allow a similar analysis for dent anomalies with metal loss or metal loss anomalies preferentially affecting the long seam. By allowing operators to perform engineering analysis on anomalies based on inline inspection data, many unnecessary digs of non-injurious anomalies can be avoided. This will allow operators to focus their resources on threats that present higher risk to their pipelines and avoid unnecessary disruptions to customers and landowners. An engineering analysis should be based on a publicly available and commonly used study, approved standard, or practice available for guidance in addressing pipeline integrity.

The capabilities of inline inspection tools have improved dramatically over the past 15 years and the requirement to respond immediately to "a dent that has any indication of metal loss" no longer reflects these capabilities.[14] The language in PHMSA's existing anomaly response regulations, originally published in 2003, does not take into account advancements in inline assessment technology and is not aligned with published technical standards in some instances. Technology advancements include improvements in tool sensitivity and detection limits, anomaly sizing accuracy, and differentiation between anomaly types. Many of the "indications" that modern inline inspection tools can now identify represent small amounts of metal loss that present minimal public risk. In the past these non-injurious anomalies were often not detected using older technologies. In many cases, small metal loss existed during the previous ILI runs, but the tools and analysis at the time were not sensitive enough to detect it. These indications do not need to be repaired immediately, since the features have likely existed for years, sometimes even decades, and are stable. When utilizing higher-capability, higher-sensitivity tools, there is also the

[13] See comments of Member Drake (12/15/17 transcript, page 9 – 10): "you know, the assumption of fracture toughness at five and one foot pounds is very, very conservative. And I think operators will have other data and other means of collecting more conservative numbers….Someone said something of 13 and four. Those are also very conservative, but a little more practicable."

Mr. Nanney with PHMSA: "All right. Yes. We were planning to do that."

[14] 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.

potential for false-positive indications.[15] Simply put, "any indication" means something very different today than it did when the anomaly response regulations were adopted approximately fifteen years ago, and is no longer an appropriate threshold for making anomaly response decisions.

The Associations conducted a comprehensive review of all onshore gas transmission pipelines incidents (inside and outside of HCAs) reported to PHMSA from 2010-2016. This review identified 9 dent-related incidents during this period, which is approximately 1% of all onshore gas transmission pipeline incidents during this period. None of these incidents involved injuries or fatalities. The low frequency of incidents caused by dents supports the Associations' proposal to add an engineering analysis approach as an alternative for managing these anomalies as monitored conditions. Many operators are currently expending significant resources to respond immediately to every dent that has any indication of metal loss on pipeline segments in HCAs. These costs will rise substantially if this criterion is extending outside of HCAs and the costs are not commensurate with the risk associated with these anomalies. 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. Furthermore, since PHMSA currently proposes to require immediate response to all dent anomalies with any indication of metal loss, this will result in significant customer disruptions as operators will be required to take immediate pressure reductions while each one of these anomalies is excavated for examination and potential repair.

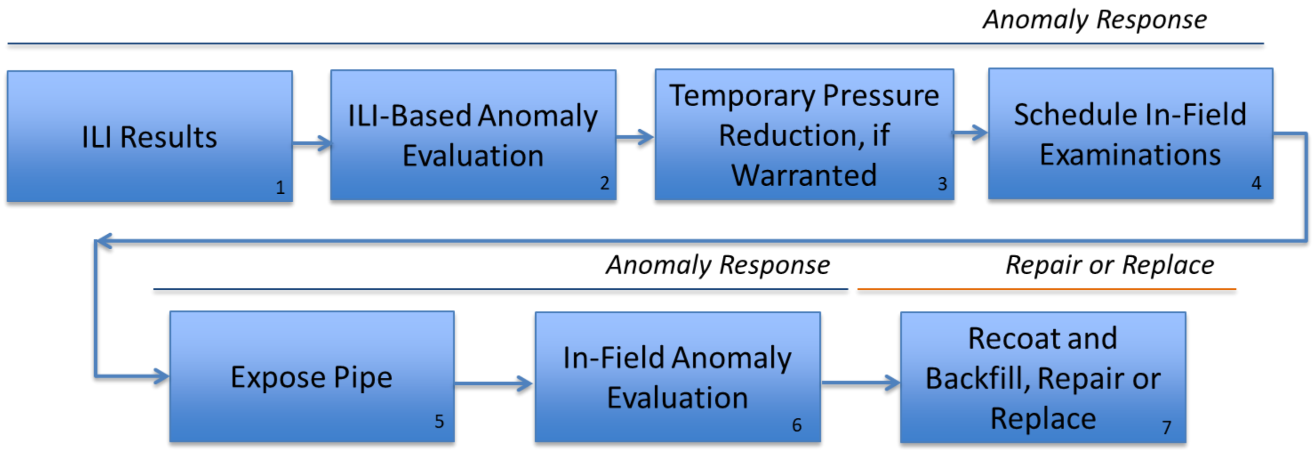
The potential expansion of dent anomaly response criteria to all pipeline segments amplifies the need for technically-supported, risk-appropriate response criteria. Adopting the Associations' proposed engineering analysis alternative would allow operators to focus resources on threats that present higher risk to their pipelines, instead of addressing non-injurious anomalies.

3) PHMSA should clarify the terminology used in §192.713 and §192.933 and that the timelines prescribed are for the operator's response, not remediation.

Both existing and proposed requirements for the response to, and repair of, potential pipeline anomalies do not recognize the important differences between actions that operators take when evaluating the results of integrity assessments versus those actions that operators take following in-field examinations of potential anomalies. The criteria in proposed §§ 192.713(d) and 192.933(d) titled "Remediation schedule" actually provide operators with the requirements related to anomaly response; i.e., these requirements describe when the operator must schedule an in-field examination to evaluate a condition discovered through integrity assessment and determine the remaining strength of the pipeline. The evaluation may include considerations for a temporary pressure reduction to ensure continued safe operation. Repairs are made after the operator has physically examined and evaluated the potential pipeline anomaly in the field. To avoid confusion and align with operator practices, the Associations propose adding a separate repair criteria paragraph within §§ 192.713 and 192.933.

After an integrity assessment, an operator follows a stepwise process to respond to the assessment findings, followed by an in-field examination and then, based on the examination results, the operator may conduct repairs. This process is depicted below:

[15] 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.



Integrity assessments provide information on conditions that may require further investigation – operators determine whether a response is required based on this information. The actual characteristics of that condition, and whether it requires repair or remediation, cannot be established without the operator conducting a physical in-field examination (a "dig") and evaluating the results of that examination. In many cases, anomalies that appear to require a repair based on initial indirect tool measurements, such as indications from an ILI report (e.g., immediate conditions), do not require repair once the anomaly is excavated, physically examined, and evaluated in the field. This is because assessment technologies use indirect measurements to infer conditions on the pipeline rather than directly measure them. Because of the limitations of these technologies compared to physical in-field examinations, the conditions (e.g. – length, depth, interaction of indications, etc.) "as called" by an assessment technology that warrant excavation and examination may be different than those conditions "found" once the anomaly has been physically examined and evaluated.

4) PHMSA should make specific modifications to align the anomaly response criteria with consensus technical standards and current technologies.

In the next section of these comments, the Associations recommend specific modifications to PHMSA's proposed regulatory text to align the anomaly response criteria with consensus technical standards and current technology capabilities. To summarize, the Associations recommend the following changes:

Dents with metal loss: Only a dent with metal loss on the top of the pipeline (8 o'clock to 4 o'clock – top two-thirds) should be an immediate response condition, as dents due to mechanical damage are most likely to occur on the top of the pipe. Gouging caused by mechanical damage is much more difficult to size and evaluate reliably. In light of these difficulties, a more conservative approach is warranted for dents with metal loss that are more likely to be due to mechanical damage.

Research and consensus technical standards support the need for immediate repair of dents with metal loss due to mechanical damage (i.e., a scratch, gouge, or stress riser), but NOT where metal loss is due to corrosion. A dent with metal loss on the bottom of a pipeline (4 o'clock to 8 o'clock – bottom one-third) should be a scheduled response condition, as the metal loss is more likely to be due to corrosion on the bottom of the pipe and bottom-side dents are typically constrained by the feature causing the dent (e.g., a rock, ledge or other material). As discussed above, a dent with indication of metal loss, cracking, or a stress riser should be a monitored condition if engineering analysis demonstrates that the dent is non-injurious.

Metal loss anomalies should be scheduled for response based on predicted failure pressure ratios in accordance with ASME B31.8S - 2004 Section 7, Figure 4 (Figure 7.2.1-1 in editions since 2012), consistent with current requirements for pipelines segments in HCAs. PHMSA has added a one-year (HCA) and two-year (non-HCA) condition related to the calculation of predicted failure pressure ratios and class location design factors. The ratios proposed by PHMSA, based on class location design factors, are contrary to those ratios that would require a one or two-year response per ASME B31.8S. The addition of the class location factor adds a redundant safety margin in addition to that already provided in B31.8S, and would result in unnecessary excavation of small metal loss anomalies. PHMSA's proposal is presented with no supporting data or analyses to demonstrate either the need or the effectiveness of the proposed change. Furthermore, PHMSA has not clarified how this requirement would be applied for segments where a class location change has occurred. For segments designed to the class 1 design factor (.72) but where there has been a "class bump" to class 2 in accordance with §192.611, a requirement to apply PHMSA's new 1.39 factor in anomaly response and repair calculations could cause *any* metal loss anomaly to require response/repair.

Cracks or crack-like defects should be evaluated using well-established fracture mechanics modeling methods to calculate failure pressures. The Associations remind PHMSA of our previously-submitted comments on PHMSA's proposed language for the fracture mechanics modeling process. PHMSA's proposed fracture mechanics modeling language (proposed § 192.624(d)) is extremely convoluted and must be rewritten for clarity. As currently drafted, the proposed language is unclear as to the required data inputs, methods and considerations for performing fracture mechanics modeling. The Associations recommended that PHMSA create a new section, § 192.712, to describe requirements for the fracture mechanics modeling process, and the Associations have recommended specific language for proposed § 192.712 to ensure clear and effective requirements. The Associations' recommended language for fracture mechanics modeling is included in the next section.

Following fracture mechanics modeling, response schedules should then be established based on failure pressure ratios consistent with the framework in API RP 1176. PHMSA should require immediate response where crack depth plus corrosion is greater than 70% of pipe wall thickness or greater than the inspection tool's maximum measurable depth, or where the anomaly is determined to have a predicted failure pressure ratio less than or equal to 1.1xMAOP. PHMSA should require one-year (HCA) or two-year (non-HCA) response where crack depth plus corrosion is greater than 50% of pipe wall thickness or the anomaly is determined to have a predicted failure pressure ratio less than or equal to 1.25xMAOP.

Definitions of Significant cracking: The Associations recommend that PHMSA remove the references to and definitions for "significant cracking." PHMSA's proposed "alternative cracking criterion" is the correct approach. The "significant" designation for stress corrosion cracking (SCC), selective seam weld corrosion (SSWC) and seam cracking is not representative of the severity of the anomaly, which is described by maximum depth or failure-pressure ratio. For example, the 10% crack depth threshold for seam cracks is overly conservative; for new pipe, gas transmission pipeline operators have employed manufacturing/construction procedures which have an acceptance limit of 10% depth for crack-like weld seam anomalies. The "significant seam cracking" definition as proposed would therefore require these operators to respond to like-new pipe as an immediate condition. Such anomalies certainly do not meet the intent of the immediate response threshold in ASME B31.8S: 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."

It's also important to note that some anomalies, such as SSWC, may be indicated as either planar (i.e., crack-like) or volumetric (i.e., metal loss) based on the type of inline inspection and the specific features of the anomaly. Crack-like anomalies should be evaluated using fracture mechanics modeling, per the Associations' proposed § 192.712, and then responses should be scheduled based on failure pressure ratios consistent with the approaches outlined in API RP 1176 and PHMSA's "alternative cracking criterion." Metal loss anomalies should be evaluated using ASME/ANSI B31G, RSTRENG, or an equivalent remaining strength method to calculate predicted failure pressure, and then responses should be scheduled per ASME/ANSI B31.8S section 7, Figure 4 (metal loss anomalies).

Metal-loss affecting a longitudinal seam should be removed from the response criteria, if the seam was formed by high-frequency electric resistance welding (HF-ERW). The Associations identified zero incidents related to corrosion or environmental corrosion cracking ("metal loss") affecting the long seam of HF-ERW pipe from 2010 – 2017. If the seam was formed by direct current or low frequency ERW, this should be a monitored condition if engineering analysis demonstrate non-injurious metal loss.

References to *metal loss greater than 50%* should be removed from the response and repair criteria regardless of location of metal loss, as this separate requirement is redundant. The proposed rule requires operators to calculate failure pressure based on metal loss and respond accordingly, consistent with the schedule in ASME B31.8S. PHMSA has not provided any technical justification or incident data for onshore gas transmission pipelines that demonstrates why a separate criteria for metal loss above 50% is warranted.

Gouge or groove indications will be evaluated as using the dent, metal loss, and/or cracking criteria that is provided elsewhere, so PHMSA's separate proposed requirements for responding to a gouge or groove greater than 12.5% of nominal wall thickness is redundant and should be removed. Furthermore, the capability of ILI technology to determine if metal loss is the result of mechanical damage or to distinguish between gouges and non-injurious metal loss is currently limited. Therefore, it is unclear how an operator could comply with the proposed requirement.

On PHMSA slide 69 from the March 2 GPAC meeting, PHMSA indicated this response criterion has been successfully implemented for liquid pipelines – this comparison is inappropriate, as ILI performance in liquid mediums is different than in gas mediums.

Manufacturing related features should only require a response if the segment has not been tested in accordance with Subpart J test levels.

B. Suggested Changes to PHMSA's Proposed Anomaly Response and Repair Regulations

The GPAC has yet to vote on the proposed anomaly response and repair criteria requirements. In advance of the next GPAC meeting, the Associations suggest modifications to the PHMSA proposed regulatory language (in **blue** below) based upon the GPAC discussions and public comment during the March 2, 2018 meeting. The Associations have also included PHMSA's proposed changes as described in the March 2, 2018 slide deck (in **red** below).

~~§192.485 Remedial measures: Transmission lines.~~

~~(a) *General corrosion.* Each segment of transmission line with general corrosion and with a remaining wall thickness less than that required for the MAOP of the pipeline must be replaced or the operating pressure reduced commensurate with the strength of the pipe based on actual remaining wall thickness. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.~~

~~(b) *Localized corrosion pitting.* Each segment of transmission line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits.~~

~~(c) Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G (incorporated by reference, *see* §192.7), or the procedure in PRCI PR 3-805 (R-STRENG) (incorporated by reference, see §192.7) for corrosion defects. Both procedures apply to corroded regions that do not penetrate the pipe wall, over 80 percent of the wall thickness and are subject to the limitations prescribed in the procedures, including the appropriate use of class location and pipe longitudinal seam factors in pressure calculations for pipe defects. When determining the predicted failure pressure (PFP) for gouges, scrapes, selective seam weld corrosion, and crack-related defects, appropriate failure criteria must be used and justification of the criteria must be documented. Pipe and material properties used in remaining strength calculations and the pressure calculations made under this paragraph must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607.~~

> §192.485 describes response and remediation procedures for corrosion anomalies. §192.485 was necessary in the past to address response and remediation of corrosion anomalies. Now that PHMSA has provided general anomaly response and repair processes for all segments and anomaly types (§192.713 and §192.933), §192.485 is redundant and creates potential for confusion. It should be eliminated for clarity.

§192.711 Transmission lines: General requirements for repair procedures.

(a) *Temporary measures ~~repairs~~.* Each operator must take immediate temporary measures to protect the public whenever:

(1) A leak, imperfection, or damage that requires an immediate response under § 192.713(d)(1) ~~impairs its serviceability~~ is found in a segment of steel transmission line operating at or above 40 percent of the SMYS; and

(2) It is not feasible to make a permanent repair at the time of discovery.

> Rather than refer to a potentially unclear term like "impairs its serviceability," PHMSA should refer to the immediate response criteria in § 192.713 for identifying anomalies that require temporary measures.

(b) *Permanent repairs.* An operator must make permanent repairs on its pipeline system according to the following:

(1) ~~Non integrity management repairs:~~ After [*the effective date of the rule*], whenever an operator discovers any condition that could adversely affect the safe operation of a pipeline segment not covered under subpart O–Gas Transmission Pipeline Integrity Management, it must correct the condition as prescribed in § 192.713(d). ~~However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator must reduce the operating pressure to a level not exceeding 80% of the operating pressure at the time the condition was discovered and take additional immediate temporary measures in accordance with paragraph (a) to protect persons or property. The operator must make permanent repairs as soon as feasible.~~

Per PHMSA March 2 GPAC meeting slide 87: "Add an effective date to 192.711(b)(1) to clarify that 192.713 is not retroactive."

Per PHMSA March 2 GPAC meeting slide 86: "To avoid duplication, refer to 192.713(d)(2) to determine the amount of the pressure reductions." By referring to the entirety of § 192.713(d) in § 192.711(b)(1), this issue is addressed.

(2) ~~Integrity management repairs:~~ When an operator discovers a condition on a pipeline covered under Subpart O-Gas Transmission Pipeline Integrity Management, the operator must remediate the condition as prescribed by §192.933~~(d)~~.

§192.713 Transmission lines: Permanent field repair of imperfections and damages.

(a) This section applies to transmission lines not covered under Subpart O-Gas Transmission Pipeline Integrity Management. Line segments that are located in high consequence areas, as defined in 192.903, must ~~also~~ comply with applicable actions specified by the integrity management requirements in subpart O.

(b) *General*. Each operator must, in repairing its pipeline systems, ensure that the repairs are made in a safe manner and are made so as to prevent damage to persons, property, or the environment. Operating pressure must be at a safe level during repair operations.

(c) *Repair*. Each imperfection or damage that requires repair under paragraph (e) of this section for ~~impairs the serviceability of~~ pipe in a steel transmission line operating at or above 40 percent of SMYS must be—

(1) Removed by cutting out and replacing a cylindrical piece of pipe; or

(2) Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe; or

(3) Remediated by a method in ASME B31.8S, Section 7, Table 4.

Rather than refer to a potentially unclear term like "impairs its serviceability," PHMSA should refer to the Associations' proposed criteria in § 192.713(e) for identifying anomalies that require repair.

Operators should be allowed to repair pipe using any of the repair methods in ASME B31.8S, which is incorporated by reference.

(d) ~~*Remediation*~~ *Response* *schedule*. For pipelines not located in high consequence areas, an operator must complete the evaluation, including in-field examination, ~~remediation~~ of a condition identified by in-line inspection completed after [*the effective date of the rule*] according to the response schedules in this paragraph. Upon completion of in-field examination and evaluation of the conditions, repairs shall be completed based on the criteria in paragraph (e) of this section. Unless a special requirement for responding to certain conditions applies, as provided in this paragraph, an operator must follow the schedule in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 7, Figure 4. Manufacturing related features meeting the criteria in this paragraph only require a response if the segment has not been tested in accordance with Subpart J test levels. If an operator cannot meet the schedule for any condition, the operator must document the reason(s) why it cannot meet the schedule and how the changed schedule will not jeopardize public safety. ~~following schedule:~~

(1) *Immediate* *response* ~~*repair*~~ *conditions*. An operator must complete the in-field examination and evaluation of ~~repair~~ the following conditions immediately upon discovery:

(i) For metal loss anomalies, a~~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; RSTRENG; or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in § 192.7(c). ~~Pipe and material properties used in remaining strength calculations must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607.~~

(A) If diameter or wall thickness records are not available, then the operator must:

(1) Use records from comparable pipe; or

PHMSA should duplicate in § 192.713 the language in current § 192.933 that references ASME/ANSI B31.8S section 7, Figure 4 for anomalies that do not have "special" response requirements outlined in this section. Furthermore, PHMSA should duplicate language directing an operator to justify the reason(s) why it cannot meet any anomaly response schedule requirements and how the changed schedule will not jeopardize public safety.

The Associations propose that PHMSA separate the concepts of response and remediation/repair. PHMSA's proposed §§ 192.713(d) and 192.933(d) inappropriately conflate anomaly RESPONSE and defect REPAIR, which are separate concepts. The Associations propose that PHMSA retitle paragraph (d) as "response" rather than remediation. The criteria in §§ 192.713(d) and 192.933(d) should be applied as response criteria, i.e., when to schedule an in-field examination to evaluate the condition and remaining strength of the pipeline. Repairs are made after the operator has physically examined and evaluated the pipeline in the field, as required by the Associations' recommended paragraph (e) below.

As discussed above, PHMSA should limit the applicability of the "TVC" requirement to MAOP records, consistent with how TVC has historically been applied.
PHMSA should reference the specific material data attributes needed to evaluate each anomaly type, and the alternatives if an operator is missing records.

Per PHMSA March 2 GPAC meeting slide 86, "Alternative Cracking Criterion:
(A) Crack depth plus corrosion > 50% of pipe wall thickness; or
(B) Crack depth plus any corrosion is greater than the inspection tool's maximum measurable depth; or
(C) The crack anomaly is determined to have (or will have prior to the next assessment) a predicted failure pressure (determined in accordance with the ECA fracture mechanics procedure) that is less than 125% of the MAOP for immediate conditions and 139% of MAOP for 1yr/2yr conditions."

(2) Verify these properties using the material documentation process specified in §192.607.

(B) If SMYS or actual material yield records are not available, then the operator must:

(1) Use data from comparable pipe;

(2) Verify these properties using the material documentation process specified in §192.607; or

(3) Assume grade A pipe (30 ksi).

(ii) For crack or crack-like anomalies:

(A) Crack depth plus corrosion is greater than 70% of pipe wall thickness;

(B) Crack depth plus any corrosion is greater than the inspection tool's maximum measurable depth; or

(C) Fracture mechanics modeling per § 192.712 shows a failure stress pressure at the location of the anomaly less than or equal to 1.1 times the maximum allowable operating pressure before the next assessment.

(iii) A dent located between the 8 o'clock and 4 o'clock positions (upper $^{2}/_{3}$ of the pipe) that has ~~any indication of~~ metal loss, cracking or a stress riser, unless engineering analysis demonstrates that the dent is non-injurious and does not pose a public safety threat in accordance with §192.713(d)(4)(iv).

(iv) Metal loss greater than 80% of nominal wall regardless of dimensions.

(v) An indication of metal-loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency ~~or high frequency~~ electric resistance welding or by electric flash welding, unless engineering analysis demonstrates that the metal loss is non-injurious and does not pose a public safety threat in accordance with §192.713(d)(4)(v).

(vi) ~~Any indication of significant stress corrosion cracking (SCC).~~

(vii) ~~Any indication of significant selective seam weld corrosion (SSWC).~~

PHMSA should align the alternative cracking criteria with API RP 1176: immediate response for crack depth plus corrosion greater than 70% of pipe wall thickness; and failure pressure ratios less than or equal to 1.1xMAOP. This is also consistent with the existing 1.1xMAOP requirement for metal loss anomalies.

Only dents with metal loss on the top of the pipeline should be an immediate response condition, as dents due to mechanical damage are most likely to occur on the top of the pipe. Research and consensus technical standards support the immediate repair of dents with metal loss due to mechanical damage (i.e., a scratch, gouge, or stress riser), but NOT where metal loss is due to corrosion. Dents with metal loss on the bottom of the pipeline should be scheduled response conditions, as the metal loss is more likely to be corrosion. A dent with indication of metal loss, cracking, or a stress riser should be a monitored condition if engineering analysis demonstrates the dent is non-injurious.

Metal loss affecting a HF-ERW seam should be removed from immediate repair. The Associations identified zero incidents related to corrosion or environmental corrosion cracking ("metal loss") incidents affecting HF-ERW pipe from 2010-2017. For DC or LF-ERW, this should be a monitored condition if engineering analysis demonstrate non-injurious metal loss.

Per PHMSA March 2 GPAC meeting slide 89, "•Delete the phrase "any indication of" from the repair criteria related to significant stress corrosion cracking, significant selective seam weld corrosion and significant seam cracking.
•Consider combining the repair criteria for these three conditions into one more general repair criterion for time-dependent cracking."

PHMSA should remove the references to and definitions for "significant cracking." PHMSA's proposed requirements for metal loss and the "alternative cracking criterion" are sufficient. The "significant" designation for SCC, SSWC, and seam cracking is not representative of the severity of the anomaly, which is described by maximum depth or failure-pressure ratio.

(viii) An indication or anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

(2) Until the examination, evaluation and repair (if required by paragraph (e)) ~~remediation~~ of a condition specified in paragraph (d)(1) is complete, an operator must reduce the operating pressure of the affected pipeline within 5 days of discovery of the condition in accordance with 192.713(d)(5). ~~to the lower of:~~

(i) ~~A level that restores the safety margin commensurate with the design factor for the Class Location in which the affected pipeline is located, determined using ASME/ANSI B31G ("Manual for Determining the Remaining Strength of Corroded Pipelines" (1991), or AGA Pipeline Research Committee Project PR-3-805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989)) ("RSTRENG," incorporated by reference, see § 192.7) for corrosion defects. Both procedures apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and are subject to the limitations prescribed in the equations procedures. When determining the predicted failure pressure (PFP) for gouges, scrapes, selective seam weld corrosion, crack-related defects, appropriate failure criteria and justification of the criteria must be used. If SMYS or actual material yield and ultimate tensile strength is not known or not adequately documented by reliable, traceable, verifiable, and complete records, then the operator must assume grade A pipe or determine the material properties based upon the material documentation program specified in § 192.607, or~~

(ii) ~~80% of pressure at the time of discovery, whichever is lower~~.

(3) *Two-year response conditions*. An operator must ~~repair~~ complete in-field examination and evaluation the following conditions within two years of discovery:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) for which engineering analyses of the dent demonstrate critical strain levels have been exceeded or, if such a strain determination is not made, 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 detected longitudinal or helical (spiral) seam weld, unless engineering analysis demonstrates that the dent is non-injurious and does not pose a public safety threat in accordance with §192.713(d)(4)(iii).

Consistent with ASME B31.8S, operators should be allowed 5 days from discovery of the condition to make the pressure reduction.

PHMSA should allow a pressure reduction and notification process when anomalies outside of HCAs cannot be addressed within the prescribed timeframes, similar to the process that exists in HCAs (§192.933(a)). Since a pressure reduction could be applied for either an immediate or scheduled condition, the pressure reduction procedure should not be located inside the "immediate response" subsection - the Associations recommend moving this language to sections d(5)

Per PHMSA March 2 GPAC meeting slide 77, "PHMSA would propose to clarify the language to not imply that the lower of the two must be used."

A dent with indication of metal loss, cracking, or a stress riser or affecting girth weld should be a monitored condition if engineering analysis demonstrates the dent is non-injurious.

(iii) ~~A calculation of the remaining strength of the pipe shows a predicted failure pressure ratio (FPR) at the location of the anomaly less than or equal to 1.25 for Class 1 locations, 1.39 for Class 2 locations, 1.67 for Class 3 locations, and 2.00 for Class 4 locations. This calculation must adequately account for the uncertainty associated with the accuracy of the tool used to perform the assessment.~~

(iv) A dent located between the 4 o'clock position and the 8 o'clock position (bottom ⅓ of the pipe) that has metal loss, cracking or a stress riser, unless engineering analysis demonstrates that the dent is non-injurious and does not pose a public safety threat in accordance with §192.713(d)(4)(iv).

(v) For crack or crack-like anomalies:

(A) Crack depth plus corrosion greater than 50% of pipe wall thickness, unless records from the previous inspection indicates the anomaly has not grown; or

(B) Fracture mechanics modeling per § 192.712 shows a failure stress pressure at the location of the anomaly less than or equal to 1.25 times the maximum allowable operating pressure before the next assessment.

(vi) ~~An area of corrosion with a predicted metal loss greater than 50% of nominal wall.~~

(vii) ~~Predicted metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld.~~

(viii) ~~A gouge or groove greater than 12.5% of nominal wall.~~

(ix) ~~Any indication of crack or crack-like defect other than an immediate condition.~~

(4) *Monitored conditions.* An operator does not have to schedule the following conditions for in-field examination and evaluation ~~remediation~~, but must record and monitor the conditions during subsequent ~~risk assessments and~~ integrity assessments for any change that may require remediation:

PHMSA has added -year (non-HCA) condition related to the calculation of the predicted failure pressure ratios and class location. The ratios proposed by PHMSA, however, are contrary to those ratios that would require a one-year response per ASME B31.8S. Class location factors are intended as design considerations – not considerations for determining whether to excavate an anomaly. The addition of the class location factor adds a redundant safety margin in addition to that already provided in B31.8S, and would result in unnecessary excavation of small metal loss anomalies. PHMSA's proposal is presented with no supporting data or analyses to demonstrate either the need or the effectiveness of the proposed change.

PHMSA should allow a one-year (HCA) or two-year (non-HCA) scheduled response for crack depth plus corrosion greater than 50% of pipe wall thickness and failure pressure ratios less than 1.25xMAOP, consistent with the framework in API RP 1176.

References to *metal loss greater than 50%* should be removed as a criterion from the final rule, regardless of location of metal loss, as this separate requirement is redundant. The proposed rule requires operators to calculate failure pressure based on metal loss and respond accordingly, consistent with the schedule in ASME B31.8S. PHMSA has not provided any technical justification for separate criteria above 50% metal loss.

Gouge or groove indications will be evaluated indications will be using dent, metal loss, and/or cracking criteria, so PHMSA's separate proposed requirements for responding to a gouge or groove greater than 12.5% of nominal wall thickness is redundant and should be removed. ILI technology, currently cannot determine if metal loss is the result of mechanical damage or discriminate between gouges and non-injurious metal loss. PHMSA's slide that indicates this has been successfully implemented for liquid pipelines is inappropriate; ILI performance in liquid mediums is different than in gas mediums.

A risk assessment does not monitor conditions – an integrity assessment does.

(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 1/3 of the pipe).

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% 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 longitudinal seam weld, and engineering analyses of the dent and girth weld or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.**

(iv) **A dent that has 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.**

(v) **Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current or low frequency electric resistance welding or by electric flash welding and an engineering analysis demonstrates that the metal loss is non-injurious and does not pose a public safety threat.**

(5) ***Temporary pressure reduction.*** **If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the segment. For any temporary reduction in operating pressure required by this section, the operator must either reduce the operating pressure to a level not exceeding 80 percent of the pressure at the time the condition was discovered or determine temporary reduction in operating pressure using the following methods:**

(i) **For corrosion metal loss defects, determine a temporary reduction in operating pressure to restore a safety margin equal to 1.1 times the operating pressure using ASME/ANSI B31G (incorporated by reference, *see* §192.7); AGA Pipeline Research Council, International, PR-3-805 (R-STRENG) (incorporated by reference, *see* §192.7) or an alternative equivalent method of remaining strength calculation. These methods are subject to the limitations prescribed in the equations procedures.**

(ii) **For gouges, scrapes, selective seam weld corrosion, and crack-related defects, appropriate failure criteria and justification of the criteria must be used. These methods are subject to the limitations prescribed in the equations procedures.**

> PHMSA should allow a pressure reduction and notification process when anomalies outside of HCAs cannot be addressed within the prescribed timeframes, similar to the process that exists in HCAs (§192.933(a)). Since a pressure reduction could be applied for either an immediate or scheduled condition, the pressure reduction procedure should not be located inside the "immediate response" subsection.

> PHMSA should remove the requirement to incorporate the Class Location design factor for calculating temporary pressure reductions. If operators implement a pressure reduction that increasing the failure pressure ratio above 1.1 x the reduced pressure, this provides a sufficient temporary safety margin until the operator can examine and potentially repair the anomaly.

> For pressure reduction procedures, PHMSA should remove references to the 80 percent wall loss limit, as it is duplicative with "subject to the limitations prescribed in the equations procedures."

An operator must notify PHMSA in accordance with paragraph (g) of this section if it cannot meet the response schedule required under paragraph (d) of this section and cannot provide safety through a temporary reduction in operating pressure or other action. An operator must also notify a State pipeline safety authority when either a segment is located in a State where PHMSA has an interstate agent agreement or an intrastate segment is regulated by that State. Operators must document the calculation method(s) or decisions used to determine reduced operating pressure and the implementation of the actual reduced operating pressure for a period of five years after the pipeline has been repaired.

It is unnecessary and redundant to restate material property requirements with respect to pressure reductions, as these requirements are already outlined in the anomaly response requirements below.

Per PHMSA March 2 GPAC meeting slide 86, "Require that operators document and keep records of the calculations or decisions used to determine the reduced operating pressure, and the implementation of the actual reduced operating pressure for a period of five years after the pipeline has been repaired (i.e., five years after the need for the pressure reduction has been alleviated)."

(6) *Long-term pressure reduction.* When a pressure reduction exceeds 365 days, the operator must notify PHMSA under paragraph (g) of this section and explain the reason for the response delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline. The operator also must notify a State pipeline safety authority when either a segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate segment is regulated by that State.

(e) *Repair Conditions.* If verified by in-field examination after [*the effective date of the rule*], an operator must repair the following conditions on the pipeline:

(1) Corrosion metal loss with a calculated allowable operating pressure less than the MAOP of the pipeline. The calculated allowable operating pressure is the predicted failure pressure based on field measurements multiplied by the design factor. The design factor shall be determined in accordance with the requirements in either §§ 192.111, 192.611(a)(3), 192.619, or 192.620. Suitable predicted failure pressure calculation methods include ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in § 192.7(c).

(i) If diameter or wall thickness records are not available, then the operator must verify these properties using the material documentation process specified in §192.607.

(ii) If SMYS or actual material yield records are not available, then the operator must:

(A) Verify these properties using the material documentation process specified in §192.607; or

(B) Assume grade A pipe (30 ksi).

(2) For crack or crack-like anomalies:

(i) Crack depth plus corrosion is greater than 50% of pipe wall thickness; or

(ii) Fracture mechanics modeling per § 192.712 shows a failure stress pressure at the location of the anomaly less than or equal to 1.25 times the maximum allowable operating pressure.

(3) Corrosion metal loss or cracking in excess of 80% depth.

(4) Dents with a depth greater than 6% of nominal pipe diameter, unless the dent strain is less than 6%

(5) Dents with a depth greater 2% affecting a girth weld or seam weld, unless engineering analyses of the dent and girth weld or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.

(6) Dents that contain corrosion in excess of what is allowed by (e)(1) of this paragraph.
(7) Dents that contain stress corrosion cracking or other cracks.
(8) Mechanical damage including gouges, scrapes, smeared metal (not metal loss due to corrosion), whether or not the mechanical damage is associated with concurrent visible indentation of the pipe.
(9) Manufacturing related features meeting the criteria in this paragraph only require repair if the segment has not been tested in accordance with Subpart J test levels.

(f) *Other conditions*. Unless another timeframe is specified in paragraph (d) of this section, an operator must take appropriate remedial action to correct any condition that could adversely affect the safe operation of a pipeline system in accordance with the criteria, schedules and methods defined in the operator's Operating and Maintenance procedures.

(g) *In situ direct examination of crack defects*. Whenever required to determine conditions that require repair in accordance with paragraph (e) ~~by this part~~, operators must perform direct examination of known locations of cracks or crack-like defects using inverse wave field extrapolation (IWEX), phased array, automated ultrasonic testing (AUT), or equivalent technology that has been validated to detect tight cracks (equal to or less than 0.008 inches crack opening). In-the-ditch examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards, including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection and in metallurgy and fracture mechanics for accuracy for the type of defects and pipe material being evaluated. The procedures must account for inaccuracies in evaluations and fracture mechanics models for failure pressure determinations.

(h) ***Notifications.*** **An operator must submit all notifications required by this section to the Associate Administrator for Pipeline Safety, by:**
(1) Sending the notification to the Office of Pipeline Safety, Pipeline and Hazardous Material Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP-10, 1200 New Jersey Avenue, SE, Washington, DC 20590-0001;
(2) Sending the notification to the Information Resources Manager by facsimile to (202) 366-7128; or
(3) Sending the notification to the Information Resources Manager by e-mail to InformationResourcesManager@dot.gov.
(4) An operator must also send a copy to a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.

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

(a) *General requirements.* An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment.
(1) *Temporary pressure reduction.* If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. For any temporary reduction in operating pressure required by this section, the operator must either reduce the operating pressure to a level not exceeding 80 percent of the operating

pressure at the time the condition was discovered **or determine temporary reduction in operating pressure using the following methods:**

(i) **For corrosion metal loss defects, determine a temporary reduction in operating pressure to restore a safety margin equal to 1.1 times the operating pressure** using ASME/ANSI B31G ("Manual for Determining the Remaining Strength of Corroded Pipelines" (1991), ~~or~~ AGA Pipeline Research Committee Project PR-3-805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989)) ("RSTRENG," incorporated by reference, see § 192.7) **or an alternative equivalent method of remaining strength calculation for corrosion defects. These methods are subject to the limitations prescribed in the equations procedures.**

(ii) **For gouges, scrapes, selective seam weld corrosion, and crack-related defects, appropriate failure criteria and justification of the criteria must be used. These methods are subject to the limitations prescribed in the equations procedures.**

PHMSA should remove the requirement to incorporate the Class Location design factor for determining temporary pressure reduction. If operators implement a pressure reduction that increasing the failure pressure ratio above 1.1 x the reduced pressure, this provides a sufficient temporary safety margin until the operator can examine and potentially repair the anomaly.

~~determine the safe operating pressure that restores the safety margin commensurate with the design factor for the Class Location in which the affected pipeline is located, determined Pipe and material properties used in remaining strength calculations must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607.~~ An operator must notify PHMSA in accordance with paragraph (g) of this section if it cannot meet the response schedule required under paragraph (c) of this section and cannot provide safety through a temporary reduction in operating pressure or other action. An operator must also notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement or an intrastate covered segment is regulated by that State. **Operators must document the calculation method(s) or decisions used to determine reduced operating pressure and the implementation of the actual reduced operating pressure for a period of five years after the pipeline has been repaired.**

It is unnecessary and redundant to restate material property requirements with respect to pressure reductions, as these requirements are already outlined in the anomaly response requirements below.

(2) *Long-term pressure reduction.* When a pressure reduction exceeds 365 days, the operator must notify PHMSA under §192.949 and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline. The operator also must notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(b) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. For the purposes of this section, a condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable. In cases where a determination is not made within the 180-day period the operator must notify OPS, in accordance with § 192.949, and provide an expected date when adequate information will become available.

(c) *Schedule for evaluation and response ~~remediation~~.* An operator must complete evaluation, including in-field examination, ~~remediation~~ of a condition according to a schedule prioritizing the conditions for response ~~evaluation and remediation~~. **Upon completion of in-field examination and evaluation of the conditions, repairs shall be completed based on the criteria in paragraph (f) of this section.** Unless a special requirement for responding to ~~remediating~~ certain conditions applies, as provided in paragraph (d) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 7, Figure 4. **Manufacturing related features meeting the criteria in this paragraph only require a response if the segment has not been tested in accordance with Subpart J test levels.** If an operator cannot meet the schedule for any condition, the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety.

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

(1) *Immediate response ~~repair conditions~~.* An operator's evaluation ~~and remediation~~ schedule must follow ASME/ANSI B31.8S, section 7 in providing for immediate response ~~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 response ~~repair~~ conditions:

(i) **For metal loss anomalies, a**~~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 ~~for any class location~~. Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation. Pipe and material properties used in remaining strength calculations must be documented in ~~reliable~~, traceable, verifiable, and complete records ~~that will provide an equally conservative result. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607.~~

(A) If diameter or wall thickness records are not available, then the operator must:

(a) Use data from comparable pipe; or

(b) Verify these properties using the material documentation process specified in §192.607.

(B) If SMYS or actual material yield records are not available, then the operator must:

(a) Use data from comparable pipe;

(b) Verify these properties using the material documentation process specified in §192.607; or

(c) Assume grade A pipe (30 ksi).

(ii) **For crack or crack-like anomalies:**

(A) Crack depth plus corrosion greater than 70% of pipe wall thickness;

(B) Crack depth plus any corrosion is greater than the inspection tool's maximum measurable depth;

(C) Fracture mechanics modeling per § 192.712 shows a failure stress pressure at the location of the anomaly less than or equal to 1.1 times the maximum allowable operating pressure before the next assessment.

(iii) 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, unless engineering analysis demonstrates that the dent is non-injurious and does not pose a public safety threat in accordance with §192.933(d)(3)(iv).

(iv) Metal loss greater than 80% of nominal wall regardless of dimensions.

(v) ~~An indication of~~ Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency ~~or high frequency~~ electric resistance welding or by electric flash welding, unless engineering analysis demonstrates that the metal loss is non-injurious and does not pose a public safety threat in accordance with §192.933(d)(3)(v).

(vi) ~~Any indication of significant stress corrosion cracking (SCC).~~

(vii) ~~Any indication of significant selective seam weld corrosion (SSWC).~~

(viii) 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 response conditions.* Except for conditions listed in paragraph (d)(1) and (d)(3) of this section, an operator must complete in-field examination and evaluation ~~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 2/3 of the pipe) for which engineering analyses of the dent demonstrate critical strain levels have been exceeded or, if such a strain determination is not made, 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 detected longitudinal or helical (spiral) seam weld, unless engineering analysis demonstrates that the dent is non-injurious and does not pose a public safety threat in accordance with §192.933(d)(3)(iii).

(iii) ~~A calculation of the remaining strength of the pipe shows a predicted failure pressure ratio (FPR) at the location of the anomaly less than or equal to 1.25 for Class 1 locations, 1.39 for Class 2 locations, 1.67 for Class 3 locations, and 2.00 for Class 4 locations. This calculation must adequately account for the uncertainty associated with the accuracy of the tool used to perform the assessment.~~

(iv) A dent located between the 4 o'clock position and the 8 o'clock position (bottom ⅓ of the pipe) that has metal loss, cracking or a stress riser, unless engineering analysis demonstrates that the dent is non-injurious and does not pose a public safety threat in accordance with §192.933(d)(3)(iv).

(v) For crack or crack-like anomalies:

(A) Crack depth plus corrosion greater than 50% of pipe wall thickness, unless records from the previous inspection indicates the anomaly has not grown; or

(B) Fracture mechanics modeling per § 192.712 shows a failure stress pressure at the location of the anomaly less than or equal to 1.25 times the maximum allowable operating pressure before the next assessment.

(vi) ~~An area of corrosion with a predicted metal loss greater than 50% of nominal wall.~~

(vii) ~~Predicted metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld.~~

(viii) ~~A gouge or groove greater than 12.5% of nominal wall.~~

(ix) ~~Any indication of crack or crack-like defect other than an immediate condition.~~

(3) *Monitored conditions.* An operator does not have to schedule the following conditions for in-field examination and evaluation ~~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 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.**

(v) **Metal-loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current or low frequency electric resistance welding or by electric flash welding and an engineering analysis demonstrates that the metal loss is non injurious and does not pose a public safety threat.**

(e) ***Repair*. Each imperfection or damage that requires repair under paragraph (f) of this section for pipe in a steel transmission line operating at or above 40 percent of SMYS must be—**

(1) **Removed by cutting out and replacing a cylindrical piece of pipe;**

(2) **Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe; or**

(3) **Remediated by an acceptable method as defined in ASME B31.8S, Section 7, Table 4.**

(f) ***Repair Conditions.* If verified by in-field examination after [*the effective date of the rule*], an operator must repair the following verified conditions on the pipeline:**

(1) **Corrosion metal loss with a calculated allowable operating pressure less than the MAOP of the pipeline. The calculated allowable operating pressure is the predicted failure pressure based on field measurements multiplied by the design factor. The design factor shall be determined in accordance with the requirements in either §§ 192.111, 192.611(a)(3), 192.619, or 192.620. Suitable predicted failure pressure calculation methods include ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in § 192.7(c).**

(i) **If diameter or wall thickness records are not available, then the operator must verify these properties using the material documentation process specified in §192.607.**

(ii) **If SMYS or actual material yield records are not available, then the operator must:**

(A) **Verify these properties using the material documentation process specified in §192.607; or**

(B) **Assume grade A pipe (30 ksi).**

(2) **For crack or crack-like anomalies:**

(i) **Crack depth plus corrosion is greater than 50% of pipe wall thickness; or**

(ii) **Fracture mechanics modeling per § 192.712 shows a failure stress pressure at the location of the anomaly less than or equal to 1.25 times the maximum allowable operating pressure.**

(3) Corrosion metal loss or cracking in excess of 80% depth.
(4) Dents with a depth greater than 6% of nominal pipe diameter, unless the dent strain is less than 6%
(5) Dents with a depth greater 2% affecting a girth weld or seam weld, unless engineering analyses of the dent and girth weld or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.
(6) Dents that contain corrosion in excess of what is allowed by (f)(1) of this paragraph.
(7) Dents that contain stress corrosion cracking or other cracks.
(8) Mechanical damage including gouges, scrapes, smeared metal (not metal loss due to corrosion), whether or not the mechanical damage is associated with concurrent visible indentation of the pipe.
(9) Manufacturing related features meeting the criteria in this paragraph only require repair if the segment has not been tested in accordance with Subpart J test levels.

§ 192.712 Fracture mechanics modeling for failure stress and crack growth analysis

(a) *Applicability*. Operators must use the process described in this section where fracture mechanics modeling is required by this part for pipeline segments that operate at a hoop stress greater than 30% of specified minimum yield strength (SMYS).
(b) *Fracture Mechanics Modeling for Failure Stress Pressure.* Failure stress pressure must be determined using a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle or both) and boundary condition used (pressure test, ILI, or other). Examples of technically proven models include but are not limited to: for the brittle failure mode, the Raju/Newman Model; for the ductile failure mode, Modified LnSec, API RP 579-1/ASME FFS-1, June 15, 2007, (API 579-1, Second Edition) – Level II or Level III, CorLas™, and PAFFC (incorporated by reference, *see* § 192.7). The analysis must use conservative assumptions for crack dimensions (length and depth) and failure mode (ductile, brittle, or both) for the microstructure, location, and type of defect.
   (1) If material toughness records are not available, then the operator must use one of the following:
      (i) Charpy energy values from comparable pipe;
      (ii) A conservative Charpy energy value to determine the toughness based upon the material documentation process specified in § 192.607;
      (iii) Maximum Charpy energy values of 13.0 ft-lb for body cracks; 4.0 ft-lb for cold weld, lack of fusion, and selective seam weld corrosion defects; or
      (iv) Other appropriate values based on technology or technical publications that an operator demonstrates can provide conservative Charpy energy values of the crack-related conditions of the line pipe.
   (2) If material strength records are not available, the analysis must use the specified minimum yield strength.
(c) *Analysis for Flaw Growth and Remaining Life.* If the operator determines that the pipeline segment is susceptible to cyclic fatigue or other loading conditions that could lead to fatigue crack growth, fatigue analysis must be performed using an applicable fatigue crack growth law (for example, Paris Law) or other technically appropriate engineering methodology. For other degradation processes that can cause crack growth, appropriate engineering analysis must be used. The above methodologies should be validated by a subject matter expert to determine conservative predictions of flaw growth and remaining life at the maximum allowable operating pressure.

(1) Initial and final flaw size must be determined using a fracture mechanics model appropriate to the failure mode (ductile, brittle or both) and boundary condition used (pressure test, ILI, or other).
(2) For cases dealing with an estimation of the defect sizes that would survive a strength test pressure, the operator must use one of the following:
 (i) Charpy energy values from comparable pipe with known properties;
 (ii) A conservative Charpy energy value to determine the toughness based upon the material documentation process specified in § 192.607;
 (iii) A full size equivalent Charpy upper-shelf energy level of 120 ft-lb; or
 (iv) Other appropriate values based on technology or technical publications that an operator demonstrates can provide conservative Charpy energy values of the crack-related conditions of the line pipe.
(3) For subsequent critical flaw size calculations at MAOP of flaws that would survive a strength test, the same Charpy energy value established in (2) may be used.
(4) The operator must re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated by this analysis has expired. The operator must determine and document if further pressure tests or use of other assessment methods are required at that time. The operator must continue to re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated in the most recent evaluation has expired.

(d) *Review.* Analyses conducted in accordance with this paragraph must be reviewed and confirmed by a subject matter expert.

> ASME B31.8S-2016 Table A-4.4-1 provides an engineering analysis approach for estimating the remaining life of SCC anomalies, based on representative SCC growth rates. This emphasizes the importance of incorporating newer versions of standards into part 192; ASME B31.8S-2004 does not provide this SCC remaining life engineering analysis method.

III. Transmission Line Definition

In the proposed rule, PHMSA suggests a modification to the *Transmission Line* definition within § 192.3. The Associations request PHMSA consider the following changes to the definition of *Transmission Line*:

- Revise the percent specified minimum yield strength (SMYS) threshold to 30% or more
- Allow operators to voluntarily designate a pipeline as transmission

Revise the threshold to 30 percent SMYS in the Transmission Line definition

PHMSA should revise the percent SMYS thresholds in the transmission line definition to 30% of SMYS or more. There is a long-documented history demonstrating that pipelines which operate at less than 30% SMYS pose significantly less risk than those that operate at greater than 30% SMYS.

Stakeholders generally accept 30% of SMYS as the "low-stress" boundary between leaks and ruptures for pipeline defects. In 2001, the Gas Research Institute developed a report examining the boundary between leaks and ruptures; the report determined that pipelines operating at less than 30% of SMYS generally leak when they fail and that ruptures generally occur on pipelines operating at greater than 30% of SMYS.[16] The Gas Technology Institute, Battelle and Kiefner & Associates have continued to study this issue, validating the 30% of SMYS threshold.[17,18,19] Furthermore, PHMSA established 30% of SMYS as a low stress threshold for integrity assessments in the gas integrity management regulations in 49 C.F.R. § 192.941(a). Finally, in the 2011 Pipeline Safety Act, Congress recognized the low risk posed by pipelines operating below 30% of SMYS and mandated that PHMSA "issue regulations for conducting tests to confirm the material strength of previously untested natural gas transmission pipelines located in HCAs and operating at a pressure greater than 30 percent of SMYS."[20]

Allow operators to voluntarily designate a pipeline as transmission

PHMSA should permit operators to voluntarily designate any pipeline segment as transmission and apply the pipeline safety requirements associated with transmission pipelines. Because of the diversity of pipeline system configurations that exist across the United States, the Associations believe that it is not possible to prescriptively define an appropriate demarcation between "transmission" and "distribution"

[16] Gas Research Institute, Leak Versus Rupture Considerations for Steel Low-Stress Pipelines, GRI-00/0232 (Jan. 2001).

[17] Gas Technology Institute, Leak-Rupture Boundary Determination, Final Report (May 4, 2011) (Including LeakRupture Calculator and Training Manual).

[18] Battelle, under contract for The INGAA Foundation in conjunction with American Gas Foundation, Integrity Characteristics for Vintage Pipelines (2005). https://primis.phmsa.dot.gov/gasimp/docs/IntegrityCharacteristicsOfVintagePipelinesLBCover.pdf .

[19] Kiefner & Associates, Inc., under contract for Gas Technology Institute, Numerical Modeling and Validation for Determination of the Leak/Rupture Boundary for Low-Stress Pipelines (2010).

[20] 49 U.S.C. § 60139(d)(1)

for every scenario; for example, different service line configurations have led to continued confusion around the point of demarcation between "transmission" and "distribution" for "farm tap" service lines.

If PHMSA adopts the Associations' recommendations related to the percent SMYS threshold, 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*, with changes to PHMSA's proposed definition indicated in **blue**:

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** ~~has an MAOP~~ of ~~20~~ **30** percent or more of SMYS;
(3) transports gas within a storage field**; or**
(4) **is voluntarily designated by the operator as 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.

IV. Remaining Topics for Vote & Discussion

The Associations commend PHMSA on the progress and tempo by which they have moved through the many complex topics in this rulemaking. In an effort to assist in ensuring that all important topics are both discussed and voted upon during the GPAC meetings, the Associations provide the following lists of topics that require votes or further discussion.

The following topics in the rulemaking have been discussed in at least one GPAC meeting, but need to be voted on:

Modifications to MAOP Determination Requirements	
§192.619(a)(4)	Proposes to reference to Material Verification requirements in one of the MAOP Determination methods.
§192.619(e)	Cross-references the MAOP Reconfirmation methods in 192.624
MAOP Reconfirmation	
§192.624	Introduces methods by which an operator can reconfirm the MAOP of applicable pipelines
Records	
§192.619(f)	Introduces a MAOP determination record requirement
IM Clarifications	
§192.917(e)(3)	Modifies the requirements for addressing the threat of manufacturing & construction defects
§192.917(e)(4)	Modifies the requirements for addressing the threats associated with ERW pipe

Response Criteria	
§192.711	Expands the requirements for non-integrity management permanent repairs on gas transmission pipelines
§192.713	Introduces response criteria for anomalous conditions found on all pipelines located outside of HCAs
§192.933	Modifies the response criteria for anomalous conditions found through integrity assessments on gas transmission pipelines located in HCAs and introduces new response criteria
Definitions	
Significant Seam Cracking	
Significant Stress Corrosion Cracking	
Significant Seam Weld Corrosion	

The following topics in the rulemaking need to be discussed by the GPAC members and then voted upon in a subsequent meeting:

References to Proposed MAOP Requirements	
§192.503(a)	Adds references to MAOP establishment methods
§192.605(b)	Adds references to the MAOP establishment methods in the requirement for overpressure protection setpoints
§192.619(a)(2)	Increases the Class Location factor for pressure testing of steel pipe located in Class 1 areas installed after the publication of the Final rule
Definitions	
Transmission Line & Distribution Center	
Traceable, Verifiable, and Complete	
Legacy Pipe, Legacy Construction Techniques, Wrinkle Bend & Modern Pipe	
Gathering Lines	
§191.23 & §191.25	Modifies reporting of safety-related conditions for Gathering lines
§192.3	Defines Gathering Line
§192.8	Expands the scope of regulated Gathering lines
§192.9	Clarifies the requirements for regulated Gathering lines
§192.13(a)	Adds a date stamp for newly regulated Gathering lines
§192.452	Specifies corrosion control requirements for newly regulated Gathering lines
§192.619 (a)(3)	Includes MAOP Determination using pressure tests for Gathering lines

Respectfully submitted,
Date: March 9, 2018

Christina Sames, *Vice President Operations and Engineering*
American Gas Association
400 North Capitol Street, NW
Washington, D.C. 20001
(202) 824-7214
csames@aga.org

Dave Murk, *Pipeline Manager*
American Petroleum Institute
1220 L Street, NW
Washington, D.C. 20005
(202) 682-8000
murkd@api.org

C.J. Osman, *Director of Operations, Safety and Integrity*
Interstate Natural Gas Association of America
20 F Street, NW
Washington, D.C. 20001
(202) 216-5912
cjosman@ingaa.org

Erin Kurilla, *Director of Operations and Pipeline Safety*
American Public Gas Association
201 Massachusetts Avenue, NE
Washington, D.C. 20002
(202) 905-2904
ekurilla@apga.org