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) MEETING
HELD DECEMBER 14-15, 2017

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AMERICAN GAS ASSOCIATION
AMERICAN PETROLEUM INSTITUTE
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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 third Gas Pipeline Advisory Committee (GPAC) meeting on the Safety of Gas Transmission & Gathering Lines Rulemaking (Proposed Rule)[5] that occurred on December 14-15, 2017.[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 two 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 December GPAC meeting are similar in content and structure.

For several topics, the December meeting produced clear and substantive direction on how to ensure that these topics are finalized in a manner that is technically feasible, reasonable, cost-effective,

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[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, 82 Fed. Reg. 51760 (November 7, 2017). 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 and Pipeline Safety: Meeting of the Gas Pipeline Safety Advisory Committee, 82 Fed. Reg. 23714 (May 23, 2017), held June 6-7 2017.

and practicable. For other topics, the conversations made strides in identifying concerns, but certain issues remain to be resolved during later meetings (for example, the GPAC still has much to discuss within the Records topic). 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 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. Proposed Changes to § 192.607: Incorporation of GPAC Votes & Industry Comments

During its December 2017 meeting, the GPAC generally voted on concepts, rather than specific language. Therefore, the Associations provide the following modifications to proposed § 192.607 for PHMSA's consideration. The Associations believe the modifications, shown in **red**, reflect the approved language as discussed at the December 2017 GPAC meeting. The Associations have also identified additional concerns that were not voted on by the GPAC, shown in **blue**, but were shared during public comment or identified through written comments by the Associations on the Proposed Rule.

§ 192.607 Verification of Pipeline Material: Onshore steel transmission pipelines

(a) Whenever required or allowed by this Part and after [*insert effective date of the final rule*], this section prescribes a process for operators of onshore steel transmission pipelines to verify unknown material properties. ~~***Applicable Locations.*** **Each operator must follow the requirements of paragraphs (b) through (d) of this section for each segment of onshore, steel, gas transmission pipeline installed before** ***[insert the effective date of the rule]*** **that does not have reliable, traceable, verifiable, and complete material documentation records for line pipe, valves, flanges, and components and meets any of the following conditions:**~~

(1) ~~**The pipeline is located in a High Consequence Area as defined in § 192.903; or**~~

(2) ~~**The pipeline is located in a class 3 or class 4 location**~~

~~(b) ***Material Documentation Plan.*** **Each operator must prepare a material documentation plan to implement all actions required by this section by** ***[insert date that is 180 days after the effective date of the rule].***~~

> Final December 2017 GPAC voting language: PHMSA will "Clarify that material verification applies to onshore steel transmission lines only (and not distribution or gathering lines)"

> Final December 2017 GPAC voting language: "In proposed paragraph (a), remove applicability criteria and make material verification a procedure for getting missing or inadequate records or verifying pipeline attributes if and when required by 192.624 or other code sections. The committee will discuss the applicability of 192.607 under each of the methods of MAOP verification discussed in 192.624 and other sections as appropriate."

> Final December 2017 GPAC voting language: "In proposed paragraph (b), delete requirements for creating a material verification program plan."

(b) ~~(c)~~ ***Material Documentation.*** For pipe properties verified using paragraph §192.607(c) of this section, ~~Each~~ operators must ~~have and~~ retain for the life of the pipeline ~~reliable,~~ traceable, verifiable, and complete records. ~~documenting the following:~~

(1) ~~For line pipe and fittings, records must document diameter, wall thickness, grade (yield strength and ultimate tensile strength), chemical composition, seam type, coating type, and manufacturing specification.~~

Final December 2017 voting language: "In proposed paragraph (c), drop the list of mandatory attributes operators must verify but require operators to keep records developed through this material verification method."

Per Mr. Nanney (12/14/17 Transcript): "… each operator would have to retain for the life of the pipeline traceable, verifiable and complete records documenting the pipe properties…established under this section. Whatever you use this section to get, we would expect you, of course, to keep those records and everything."

(2) ~~For valves, records must document either the applicable standards to which the component was manufactured, the manufacturing rating, or the pressure rating. For valves with pipe weld ends, records must document the valve material grade and weld end bevel condition to ensure compatibility with pipe end conditions;~~

(3) ~~For flanges, records must document either the applicable standards to which the component was manufactured, the manufacturing rating, or the pressure rating, and the material grade and weld end bevel condition to ensure compatibility with pipe end conditions;~~

(4) ~~For components, records must document the applicable standards to which the component was manufactured to ensure pressure rating compatibility;~~

(c) ~~(d)~~ ***Verification of Material Properties***. For any material documentation records for line pipe, valves, flanges, and components ~~specified in paragraph (c)~~ that are required to be verified ~~this section that are not available~~, the operator must take the following actions to determine and verify the physical characteristics.

(1) Develop and implement procedures for conducting non-destructive or destructive tests, examinations, and assessments for line pipe at ~~all~~ above ground locations.

(2) Develop and implement procedures for conducting non-destructive or destructive tests, examinations, and assessments for buried line pipe at ~~all~~ excavations associated with replacements or relocations of pipe segments that are removed from service.

(3) Develop and implement procedures for conducting non-destructive or destructive tests, examinations, and assessments for buried line pipe at ~~all~~ excavations associated with anomaly direct examinations, *in situ* evaluations, repairs, remediations, or maintenance, ~~or any other reason for which the pipe segment is exposed,~~ except for segments exposed during excavation

Final December 2017 GPAC voting language: PHMSA will "Retain flexibility to allow either destructive or non-destructive tests when verification is needed"

PHMSA agreed to consider deleting the requirement for testing when the pipe is exposed for "any other reason." (6/7/17 transcript, Page 169.)

activities that are conducted to comply with ~~in compliance with~~ § 192.614, until completion of the minimum number of excavations as follows.

~~(i) the operator must define a separate population of undocumented or inadequately documented pipeline segments for each unique combination of the following attributes: wall thicknesses (within 10 percent of the smallest wall thickness in the population), grade, manufacturing process, pipe manufacturing dates (within a two-year interval) and construction dates (within a two year interval).~~

(i) Assessments must be proportionally spaced throughout the pipeline segment. Each length of the pipeline segment equal to 10 percent of the total length must contain 10 percent of the total number of required excavations, e.g. a 200 mile segment ~~population~~ would require 15 excavations for each 20 miles. ~~For each population defined according to (i) above, T~~The minimum number of excavations at which line pipe must be tested to verify pipeline material properties is the lesser of (A) or (B) below: ~~the following:~~

(A) 150 excavations; or

(B) If the segment is less than 150 miles, a number of excavations equal to the ~~population's~~ pipeline mileage (i.e., one set of properties per mile), rounded up to the nearest whole number.

Final December 2017 GPAC voting language: "Clarify the applicability of 192.607(d)(3)(i)."

The Associations suggest that by removing the term "population" and adding §192.607(c)(3)(i)(C) below, operators can choose the sampling approach in §192.607(c)(3)(i)(A) and (B) or develop alternative sampling methods and submit a notice to PHMSA under §192.607(c)(6). Several operators have already developed similar methodologies and position papers while conducting MAOP validation.

Final December 2017 GPAC voting language: "Retain the opportunistic approach of obtaining unknown or undocumented material properties when excavations are performed for other repairs or other reasons, using a one-per-mile standard proposed by PHMSA, but allow operators to use their own statistical approach and submit a notification to PHMSA with their method. Establish a minimum standard of a 95% confidence level for operator statistical methods submitted to PHMSA." Also: "Revise the paragraph to accommodate situations where a single material verification test is needed (e.g. additional information is needed for an anomaly evaluation / repair)."

The GPAC voted on applying a 95% confidence interval. However, the hazardous liquid rule proposed a 90% confidence interval for material properties. As such, the Associations suggest changing the confidence interval to 90% to be consistent with the hazardous liquids rule.

~~The mileage for this calculation is the cumulative mileage of pipeline segments in the population without reliable, traceable, verifiable, and complete material documentation.~~

(C) In lieu of (A) and (B) above, an operator may use another process and submit notification to PHMSA in accordance with 192.607(c)(6). The alternative process must establish a minimum 90% confidence level standard for any pipe material sampling process utilized.

(ii) At each excavation, ~~tests for material properties must~~ ~~determine diameter, wall thickness, yield strength, ultimate tensile strength, Charpy v-notch toughness (where required for failure pressure and crack growth analysis), chemical properties, seam type, coating type, and must test for the presence of stress corrosion cracking, seam cracking, or selective seam weld corrosion using ultrasonic inspection, magnetic particle, liquid penetrant, or other appropriate non-destructive examination techniques. D~~determination of material property values must conservatively account for measurement inaccuracy and uncertainty. ~~based upon the use of reliable engineering testing and analysis. comparison with destructive test results using unity charts.~~

Final December 2017 GPAC voting language: "In proposed paragraph (c), drop the list of mandatory attributes operators must verify but require operators to keep records developed through this material verification method."

Chemical composition is not needed for MAOP reconfirmation or anomaly response calculations.

Final December 2017 GPAC voting language: "Drop accuracy specifications (retain requirement that test methods must be validated and that calibrated equipment be used)."

(iii) If non-destructive tests are performed to determine strength ~~or chemical composition~~, the operator must use methods, ~~tools,~~ procedures, and techniques that have been ~~independently~~ validated by subject matter experts, and utilize calibrated equipment. ~~in metallurgy and fracture mechanics to produce results that are accurate within 10% of the actual value with 95% confidence for strength values, within 25% of the actual value with 85% confidence for carbon percentage and within 20% of the actual value with 90% confidence for manganese, chromium, molybdenum, and vanadium~~

Final December 2017 GPAC voting language: "Drop mandatory requirements for multiple test locations for large excavations (multiple joints within the same excavation)." Also, per Mr. Nanney (12/14/17 transcript pg. 53): "Also, we would drop the mandatory requirements for multiple locations for large excavations. In other words, it would only be **one test in two quadrants**. And then, for NDE tests, like I just said, we would reduce the number of quadrants from four to two for the test."

~~percentage for the grade of steel being tested.~~

(iv) ~~The minimum number of test locations at each excavation or above-ground location is based on the number of joints of line pipe exposed, as follows:~~

~~(A) 10 joints or less: one set of tests for each joint.~~

~~(B) 11 to 100 joints: one set of tests for each five joints, but not less than 10 sets of tests.~~

~~(C) Over 100 joints: one set of tests for each 10 joints, but not less than 20 sets of tests.~~

(iv) For non-destructive tests, at each test location, a set of material properties tests must be conducted at a minimum of ~~five places in each circumferential quadrant of the pipe for a minimum total of 20 test readings at each pipe cylinder location.~~ two circumferential quadrants of the pipe.

(v) For destructive tests, at each test location, a set of materials properties tests must be conducted on two ~~each~~ circumferential quadrants of a test pipe cylinder removed from each location.~~, for a minimum total of four tests at each location.~~

(vi) If the results of all tests conducted in accordance with paragraph~~s (d)(3)(i) and (ii)~~ (c)(3)(i) of this section verify that material properties are consistent with all available information for each ~~population~~ pipe segment or existing assumptions are more conservative than test results, then no additional excavations are necessary. However, if the test results identify line pipe with properties that are not consistent with existing information ~~expectations based on all available information for each population, then the operator must perform tests at additional excavations.~~ or yield more conservative results than the current assumptions based on all available information, then the operator must modify their material verification process and submit notification

Final December 2017 GPAC voting language: "Reduce number of quadrants at which NDE tests must be made from 4 to 2." Still, the Associations note that API 5L, which is incorporated by reference in §192.7, requires testing of one quadrant.

Final December 2017 GPAC voting language: "Delete specified program requirements for how to address sampling failures and replace with a requirement for operators to determine how to deal with sample failures through an expanded sample program that is specific to their system and circumstances. Require notification to provide expanded sample program to PHMSA, and require operators establish a minimum standard that sampling programs must be based on a minimum 95% confidence level."

The Associations encourage PHMSA to revisit the proposed requirement to perform additional test if any test results are different than original assumptions. The Associations suggest if material verification yields more conservative material properties, operators should be allowed to apply these values instead of conducting additional testing.

to PHMSA in accordance with 192.607(c)(6), or apply the more conservative values. The expanded process must establish a minimum 90% confidence level standard for any pipe material verification process utilized. ~~The minimum number of excavations that must be tested depends on the number of inconsistencies observed as-found tests and available operator records, in accordance with the following table.~~

> The GPAC voted on applying a 95% confidence interval. However, PHMSA's "Safety of Hazardous Liquids Pipelines" proposed rule proposes a 90% confidence interval for material properties. As such, the Associations suggest changing the confidence interval to 90% for consistency.

~~Number of Excavations with Inconsistency Between Test Results and Existing Expectations Based on All Available Information for each Population~~	~~Minimum Number of Total Required Excavations for Population. The lesser of:~~
~~0~~	~~150 (or pipeline mileage)~~
~~1~~	~~225 (or pipeline mileage times 1.5)~~
~~2~~	~~300 (or pipeline mileage times 2)~~
~~>2~~	~~350 or pipeline mileage times 2.3)~~

(vii) The tests conducted for a single excavation according to the requirements of paragraphs ~~(d)(3)(iii)~~(c)(3)(ii) through ~~(vii)~~(v) of this section count as one sample under the sampling requirements of paragraphs ~~(d)~~(c)(3)(i)~~, (ii)~~ and ~~(viii)~~(vi) of this section.

(4) When this section is used to establish material properties for mainline pipeline components other than line pipe, the operator must develop and implement procedures for establishing and documenting any of the following: the applicable standards to which the component was manufactured, the manufacturing rating, or the pressure rating. ~~ANSI rating and material grade (to assure compatibility with pipe ends).~~

> The Associations suggest that the language in this section should be consistent with the language required prospectively in §192.205. (Note: §192.205 has not been voted on yet.)

(i) Materials in compressor stations, meter stations, regulator stations, separators, river crossing headers, mainline valve assemblies, operator piping, or cross-connections with isolation valves from the mainline pipeline are not required to be tested for chemical and mechanical properties.

(ii) Verification of mainline material properties is required for non-line pipe components, including but not limited to, valves, flanges, fittings, fabricated assemblies, and other pressure retaining components appurtenances that are:

(A) Larger than 2-inch nominal diameter ~~and larger or~~

(B) Material grades greater than 42,000 psi (X-42), or

(C) Appurtenances of any size that are directly installed on the pipeline and cannot be isolated from mainline pipeline pressures.

During the June GPAC meeting, PHMSA agreed to consider changing the threshold for non-line pipe components to larger than 2-inch nominal diameter. See comments of Mr. Nanney on pp. 162 of June 7 transcript.

(iii) Procedures for establishing material properties for non-line pipe components where records are inadequate must be based upon documented manufacturing specifications. Where specifications are not known, usage of manufacturer's stamped or tagged material pressure ratings and material type may be used to establish pressure rating. The operator must document the basis of the material properties established using such procedures.

(5) The material properties determined from the destructive or non-destructive tests required by this section cannot be used to raise the original grade or specification of the material, which must be based upon the applicable standard referenced in § 192.7.

Because of the diversity of processes and technologies that could be used to satisfy the objectives of 192.607, PHMSA should clarify that operators can submit notifications of the intent to use "other technology or another process."

(6) If conditions make material verification by the above methods impracticable or if the operator chooses to use other technology or another process ~~"new technology" (alternative technical evaluation),~~ other than those described by this section, the operator must notify PHMSA at least ~~180~~ 90 days in advance of use in accordance with paragraph (e) ~~§ 192.624(e)~~ of this section. The operator must submit a description of the other technology or process ~~the alternative technical evaluation process plan~~ to the Associate Administrator of Pipeline Safety with the notification. ~~and must obtain a "no objection letter" from the Associate Administrator of Pipeline Safety prior to usage of an alternative evaluation process.~~ If an operator does not receive an objection letter from PHMSA within 90 days of notifying PHMSA, the operator can proceed with the other technology or process. PHMSA will notify the operator within 90 days of the request if additional review time is needed.

Final December 2017 GPAC voting language: "Incorporate language stating that, if an operator does not receive an objection letter from PHMSA within 90 days of notifying PHMSA of an alternative sampling approach, the operator can proceed with their method. PHMSA will notify the operator if additional review time is needed."

(e) *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.

Rather than refer to the "notifications" paragraph within the MAOP reconfirmation section, PHMSA should simply include notification instructions in this section for clarity.

III. MAOP Determination and Reconfirmation (§192.619 and §192.624)

A. General Comments

The GPAC spent several hours on December 14 and December 15 discussing various important issues related to PHMSA's proposed maximum allowable operating pressure (MAOP) reconfirmation requirements for transmission lines. Rather than review the entirety of those discussions, the Associations highlight three key issues that PHMSA should consider in advance of the March GPAC meeting based on the December discussion:

(1) PHMSA should limit the applicability of MAOP reconfirmation to pipeline segments with MAOPs greater than 30% of specified minimum yield strength (SMYS) and should eliminate Method 5

(2) PHMSA should focus the MAOP reconfirmation process on one-time actions needed to confirm material strength and MAOP

(3) PHMSA should minimize changes to § 192.619, which applies to all gas pipelines

(1) ***PHMSA should limit the applicability of MAOP reconfirmation to pipeline segments with MAOPs greater than 30% of 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.[8] The Gas Technology Institute, Battelle and Kiefner & Associates have continued to study this issue, validating the 30% of SMYS threshold.[9,10,11] 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."[12] Thus, PHMSA should exclude pipelines with MAOPs below 30% of SMYS from the MAOP reconfirmation requirements, because doing so would

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

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

[10] 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 .

[11] 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).

[12] 49 U.S.C. § 60139(d)(1)

ensure consistency with Congress's direction, PHMSA's own regulations, and industry research and consensus.

The goal of MAOP reconfirmation is to confirm material strength for pipeline segments that do not have records of the Subpart J pressure test that is required for all new pipelines. Pressure testing confirms material strength by addressing critical, resident manufacturing and construction anomalies. As discussed during the GPAC meeting, ruptures of gas pipelines operating below 30% SMYS are rare[13], and even those that have occurred were generally not associated with the manufacturing and construction threats that pressure testing is intended to address.[14] In a 2013 report, Kiefner & Associates and Kleinfelder identified nine in-service incidents occurring on gas pipelines operating below 30% SMYS (including transmission, distribution and gathering) going back to approximately 1990.[15] These incidents were caused by corrosion and outside force damage (such as mechanical damage and earth movement), not by manufacturing-or construction-related issues.

MAOP reconfirmation is not the appropriate way to manage the threats that lead to ruptures on low SMYS pipelines, particularly the time-dependent threat of corrosion. These threats are managed through ongoing corrosion control, maintenance, and integrity management activities. In fact, the GPAC recently approved a series of more rigorous corrosion control requirements all pipelines at the June 2017 GPAC meeting (within 49 CFR 192 Subpart I: *Requirements for Corrosion Control*), which will further enhance corrosion control for ongoing operations. As indicated in previous comments, the Associations support the additional corrosion control regulations as voted on by the GPAC in June 2017.[16] The Associations emphasize that Subpart I is the appropriate place to address the relevant corrosion threats for pipeline segments outside of HCAs with MAOPs less than 30% of SMYS.

Furthermore, segments with MAOPs below 30% of SMYS tend to have smaller diameters and tend to be directly involved in the delivery of natural gas to end users. Due to the location and use of these pipelines, significant maintenance tasks, such as those proposed for MAOP reconfirmation, will result in

[13] Regarding the rarity of ruptures below 30% SMYS:

- Mr. McLaren with PHMSA (12/14/17 Transcript, pages 232-233): "Well, the 30-percent SMYS has traditionally been identified as the ratio where you would go from a leak to a rupture, not wanting a rupture."
- Member Zamarin (12/14/17 Transcript, page 237): "The 30-percent SMYS criteria is a criteria that has been established through a lot of research and a lot of analysis that demonstrates that, for the vast, vast majority, there is a de minimis amount of risk below that stress level that a pipeline would fail catastrophically and cause a significant impact to life and property."
- Member Brownstein (12/15/17 Transcript, page 26-27): "So, we're saying that the, that there's a low probability of rupture below those pressures? Is that right?" Mr. Mayberry with PHMSA: "Much lower. It has happened, but lower."

[14] Member Drake (12/15/17 Transcript, page 6-7): "The reason that was put into place at 30 percent was because of the pre-disposition to leak. And that [pressure] testing wasn't going to help identify manufacturing issues that would grow to failure, or construction issues that would surface as a failure at that stress level."

[15] Kiefner & Associates, Inc. and Kleinfelder, Study of pipelines that ruptured while operating at a hoop stress below 30% SMYS (February 2010).

[16] Comments on PHMSA's Gas Pipeline Advisory Committee (GPAC) Meeting Held June 6-7, 2017, (filed by AGA, API and INGAA on August 2, 2017). http://www.ingaa.org/Filings/RegulatoryFilings/32788.aspx.

particularly severe disruptions to customers. Many of these pipelines are one-way feeds and the only supply of gas, requiring temporary bypasses or use of multiple LNG/CNG trailers to be used to maintain gas service during MAOP reconfirmation activities. In addition, many of these lines operate at lower pressures, have multiple valves and lateral lines, and include bends that make it difficult or impossible to conduct inline inspection or remove water from the line if a hydrostatic test is conducted. These limitations will greatly increase the costs to reconfirm the MAOP for these segments. Excluding segments with MAOPs below 30% of SMYS from the MAOP reconfirmation requirements will enable significant resources to be directed towards higher impact safety work to address higher risk areas; the Associations estimate that this change would decrease the burden of this rulemaking by billions of dollars, enabling those resources to be allocated towards projects that can more immediately impact pipeline safety.[17]

PHMSA should limit the applicability of MAOP reconfirmation to pipeline segments with MAOPs greater than 30% of SMYS. Since the currently-proposed "Method 5" for MAOP reconfirmation would only apply to pipelines with MAOPs less than 30% of SMYS, PHMSA should eliminate proposed Method 5. However, if PHMSA does not limit the applicability of § 192.624 to pipeline segments with MAOPs greater than 30% of SMYS, changes are needed to make Method 5 practicable. The Associations have noted these issues in proposed changes to § 192.624 below.

(2) ***PHMSA should focus the MAOP reconfirmation process on one-time actions needed to confirm material strength and MAOP.***

As discussed during the GPAC meeting, a single pressure test to Subpart J: *Test Requirements*, or prior testing to Subpart J pressure test levels, is a conservative and proven method to establish MAOP. A Subpart J-level pressure test establishes a conservative safety margin that serves as the starting point for managing a pipeline's integrity. An operator then uses ongoing corrosion control, operations, maintenance, and integrity management activities to continuously manage the condition of the pipeline, per Subparts I: *Requirements for Corrosion Control*, L: *Operations*, M: *Maintenance* and O: *Gas Transmission Pipeline Integrity Management*). If its condition deteriorates, a pipeline is evaluated using proven inspection and assessment methods to ensure safe continued operation, or it is repaired or replaced to restore the conservative safety margin. PHMSA should remove requirements related to corrosion control, operations, maintenance and integrity management from §192.624, as these are more appropriately addressed elsewhere in Part 192. In particular, PHMSA should:

(a) Eliminate the requirement that operators use a spike test to reconfirm MAOP

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[17] Regarding the disproportionate cost associated with reconfirming MAOP for segments operating below 30% SMYS:

- Ms. Toczylowksi with Consolidated Edison Company of New York (12/14/17 transcript, page 197): "As proposed, Con Edison's only viable option to comply with this proposed regulation is to replace our entire transmission system…. As written, the cost to comply with this section of the rule will cost Con Edison and our customers over $2.5 billion in current-day dollars. In comparison, if the rule was applied to pipe greater than 30-percent SMYS, the cost would be $400 million."
- Mr. Chittick with TransCanada (12/14/17 transcript, page 195): "As identified in the presentation, about 25 percent of the mileage of pipe that requires reconfirmation is within this grouping, small diameter, low pressure, low risk. When I look at the TransCanada system, on one of our pipelines we have 750 segments spread out amongst 250 pipelines that fall into this category. And the option of derating by 10 percent just isn't practical. These pipelines form part of overall networks, and we can't derate them readily by 10 percent."

(b) Refine Method 3 – Engineering Critical Assessment to focus on inspections and analyses necessary to assess manufacturing and construction-related features and confirm material strength

(c) Revise the applicability of §192.624 to exclude segments that have traceable, verifiable, and complete (TVC) pressure test records, but have experienced a reportable incident. Allow these segments to be managed under existing and proposed corrosion control, operations, maintenance, and integrity programs.

(d) Relocate the fracture mechanics modeling process to a new § 192.712

(a) *Eliminate the requirement that operators use a spike test to reconfirm MAOP for certain segments*

PHMSA should withdraw the proposal for spike hydrostatic pressure testing for MAOP reconfirmation (§192.624(c)(1)(ii)). Spike testing is not an appropriate technique for MAOP reconfirmation, and will result in unintended negative consequences without improving pipeline safety. The goal of MAOP reconfirmation is to confirm the material strength of pipelines that do not have records of a pressure test to Subpart J levels. MAOP reconfirmation involves confirming the material strength of the pipeline by addressing any critical, resident manufacturing and construction anomalies. This approach is consistent with the existing Subpart J pressure test that is currently required for all new pipelines.

In contrast, spike testing was designed as an integrity assessment technique for exposing significant time-dependent linear defects, including environmental cracking, such as stress corrosion cracking (SCC). SCC has been identified as the only significant time-dependent linear defect threat on gas pipelines. The NPRM proposes to require spike testing to reconfirm the MAOP of certain "legacy pipelines" and pipelines that utilized "legacy construction techniques," even though Subpart J pressure testing, and not spike hydrostatic pressure testing, is the long-standing method for establishing or reconfirming MAOP.[18]

In fact, PHMSA commissioned Kiefner & Associates to develop a report which "presents guidelines for evaluating integrity-management plans of natural gas pipeline operators with respect to managing the

[18] Regarding the misapplication of spike testing for MAOP reconfirmation:

- Member Drake (12/14/17 Transcript, pages 264-265): "I do think that the spike test is pretty straightforward here. We've had a lot of conversations. I think that was a misapplication. I don't want to beat a dead horse, but we're all for hydrostatically testing with the spike test for cracks. I think that makes sense. It's an integrity test. We've used it many times. It's very appropriate. But, for setting MAOP, just broadly, not appropriate. It also creates a curious disconnection with our current federal regulations which require that pipes today that we're building right now be tested without a spike test….I think it was just a dislocation in how this came across the transom from NTSB, and I think we need to kind of reset. Spike testing is a test for crack-like integrity issues. Subpart (j), straight hydrostatic testing is appropriate for MAOP. If you have a crack issue that you're worried about and you're going to set the MAOP, then go for the spike test, but it's not universally applied for the MAOP setting."
- Mr. Nanney with PHMSA (12/14/17 Transcript, pages 271): "It was a spike test where you had cause to use one, was our intent there. And I think what I've heard Andy, Chad, and some say, is I think some of what they've said and our intent here is very similar. And we'll go back and look at that."

risk posed by pipe manufacturing and pipeline construction threats."[19] The report finds that "experience shows that a test-pressure-to-operating ratio of 1.25 provides adequate assurance of stability" and that "the assurance of stability demonstrated by a test-pressure-to-operating-pressure ratio of 1.25 or more is valid for the conceivable life of most gas pipelines."[20] The Associations agree that all pipelines required to be pressure tested for MAOP reconfirmation should be tested to at least 1.25 x MAOP; however, it is unnecessary for PHMSA to require pipelines to undergo an additional spike test (i.e., above 1.25 x MAOP) in order to address the threat of manufacturing and construction defects.

Spike testing is an aggressive and destructive test that yields no added benefits from an MAOP establishment perspective, but imparts significant stresses on the pipeline, its components, and the testing equipment. This can increase the risk of failures of piping and components that would otherwise pose no threat during the service life of the pipeline. Such failures would require repairs and cause other adverse effects, such as further customer service disruptions.

The benefits and sufficiency of Subpart J pressure testing, consistent with the test levels in §192.619, for purposes of establishing material strength are well documented in technical literature and reflected in PHMSA's existing regulations. The goal of MAOP reconfirmation is to confirm material strength for pipelines lacking a record of a pressure test by addressing critical, resident manufacturing and construction anomalies, consistent with the Subpart J pressure test that is now required for all new pipelines. "Resident" features are present from original manufacturing and historical construction techniques and do not grow in service unless acted upon by other threats such as external corrosion, outside force, or pressure cycling. Ongoing corrosion control, operations, maintenance, and integrity programs manage each of these other threats, including their interaction with resident features.

(b) *Refine Method 3 – Engineering Critical Assessment to focus on inspections and analyses necessary to assess manufacturing and construction-related features and confirm material strength*

Engineering Critical Assessment (ECA) using an in-line inspection (ILI) process provides the operator with significant information about the condition of the original pipeline manufacturing and construction features, including information on anomalies that could survive a pressure test. ECA with ILI has the ability to provide this information with minimal environmental impacts and service disruptions. As stated above, reconfirming a pipeline's material strength validates its MAOP, and is different from the ongoing process of managing the threats and risks to a pipeline.[21] PHMSA should remove requirements from this section that are relevant to corrosion control, maintenance, operations, and integrity management, but not needed to prove material strength, and that are required elsewhere in Part 192. Specifically, PHMSA

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[19] Kiefner & Assoc. under contract for PHMSA, Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines (May 2007). https://primis.phmsa.dot.gov/gasimp/docs/Evaluating_Stability_of_Defects.pdf.

[20] *Id.*

[21] Regarding the separation of MAOP reconfirmation from integrity management:

- Mr. Nanney with PHMSA (12/14/17 Transcript, pages 169): "PHMSA intends the MAOP testing to be a separate process."
- Member Drake (12/15/17 Transcript, pages 14): "You're going to get the integrity management discussions separately, when you talk about how to manage threats for 30 percent pipes in integrity management."

should remove requirements related to threat assessment, in-service degradation, loadings, and operational circumstances and Subpart I assessments such as coating and interference surveys.

The ECA method is composed of several analyses to confirm material strength.Different material properties are critical for each analysis method. The Associations propose that the required material properties for volumetric anomaly response calculations are grade, diameter, wall thickness and longitudinal seam factor. Similarly, for planar including crack-like features, the required material properties for anomaly response calculations are grade, diameter, wall thickness, longitudinal seam factor and toughness.

(c) *Revise the applicability of §192.624 to exclude segments that have TVC pressure test records, but have experienced a reportable incident. Allow these segments to be managed under existing and proposed corrosion control, operations, maintenance, and integrity programs.*

A reportable incident in and of itself does not invalidate MAOP for the entire segment or pipeline, and addressing the threats that have caused a pipeline incident is more effectively accomplished through ongoing corrosion control, operations, maintenance, integrity assessment, and anomaly response requirements.[22] PHMSA proposes to expand integrity assessment (§ 192.710) and anomaly response requirements (§ 192.713) beyond HCAs to segments in class 3 and 4 locations and segments in Moderate Consequence Areas that can accommodate inline inspection.

Requiring pipelines that have had an in-service incident to reconfirm their MAOP creates regulatory confusion. This requirement is linked to Integrity Management (§ 192.917(e)(3)) and is misplaced in the MAOP reconfirmation requirements.

(d) *Relocate the fracture mechanics modeling to a new § 192.712*

Fracture mechanics modeling has an important but specific role in preventing pipeline failures. Fracture mechanics modeling is a valuable tool for determining the predicted failure pressure and remaining life for cracks and crack-like defects. However, PHMSA proposes to require fracture mechanics modeling as part of all MAOP reconfirmation methods; this is overbroad and unnecessary. For example, fracture mechanics modeling is inappropriate and unnecessary for MAOP reconfirmation when Subpart J pressure testing has been completed. Subpart J is the long-standing method for establishing or reconfirming MAOP.

Fracture mechanics modeling should be required exclusively for the following distinct purposes:

[22] Regarding addressing reportable incidents separately from MAOP reconfirmation:

- Member Zamarin (12/14/17 Transcript, page 223-225): “When an incident occurs, typically irrespective of whether or not it’s a high-consequence area, but if it’s in a Class 3 or 4, a high-consequence area, we have to take immediate corrective action. Typically, PHMSA will also take corrective action and issue expectations on what needs to be performed prior to returning the line to service…. Again, this section is about confirming the MAOP of pipelines that haven’t been previously tested or grandfathered, or don’t have records for MAOP. It just doesn’t feel like it’s the section to address this issue….I think there’s another part of the rulemaking where we’re going to talk about extending integrity management. That may be an area where we want to talk about what we should be doing beyond the traditional HCA definition.”

- To calculate the failure pressure of an indicated or proven defect as part of an ECA (Method 3) to reconfirm MAOP;
- To calculate the failure pressure of an indicated or proven defect to establish a response schedule per § 192.713 and § 192.933; or
- To estimate the largest defect that could have survived a pressure test for conducting crack growth analysis. This is appropriate when an operator uses operating history to establish a test pressure ratio lower than what is prescribed in Subpart J (*e.g.*, Method 2 to reconfirm MAOP). If a pipeline segment is susceptible to failure due to fatigue, crack growth considerations are also required in PHMSA's proposed changes to § 192.917(e)(2), which the GPAC approved (with modifications) at its June 2017 meeting.

As indicated above, the different applications for fracture mechanics modeling are addressed in distinct code sections: § 192.624, § 192.713, § 192.917 and § 192.933. To establish clear and consistent requirements for the fracture mechanics modeling process, the Associations recommend that PHMSA create a new section, § 192.712, which would simply describe requirements for the fracture mechanics modeling process. The applicability of the fracture mechanics modeling process in § 192.712 would be defined in each relevant section, similar to how PHMSA proposed to apply § 192.607 at the December GPAC meeting.

Furthermore, for gas pipelines, considerations for cyclic fatigue-induced growth are not appropriate in most instances where fracture mechanics modeling is warranted, and this should be recognized within § 192.712. Gas pipelines generally have stable pressures and as a result are not typically susceptible to cyclic fatigue.[23] Cyclic fatigue is more typically found in liquids pipelines, which tend to have greater pressure swings that lead to fatigue. As a senior PHMSA engineer explained during PHMSA's June 8, 2016 webinar, "Gas pipelines normally don't have cyclic fatigue issues, so on many or most of the lines; this problem will not be too much of a factor."[24] Therefore, the Associations propose a separate paragraph, § 192.712(c), which would describe required methods in the event crack growth and remaining life calculations are needed and if the operator determines that the pipeline segment is susceptible to cyclic fatigue or other loading conditions.

Finally, PHMSA's proposed language for the fracture mechanics modeling process 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. For example, the first sentence of PHMSA's new language in proposed § 192.624(d) contains 124 words. The Associations offer alternative language below to restate the fracture mechanics modeling process that PHMSA has proposed in a clearer fashion. The Associations have also recommended new references within § 192.624 to the proposed fracture mechanics modeling section, § 192.712. When the GPAC discusses proposed additions and changes to anomaly response and repair criteria (§ 192.713 and §

[23] M.J. Rosenfeld, & J.F. Kiefner, Pipeline Research Council International Inc., Basics of Metal Fatigue in Natural Gas Pipeline Systems – A Primer for Gas Operations, Contract PR-302-03152 (June 30, 2006) ; BMT Fleet Technology, Fatigue Considerations for Natural Gas Pipelines (June 30, 2016).

[24] Safety of the Nation's Gas Transmission Pipelines – NPRM (June 8, 2016). https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=117.

192.933), the GPAC should also discuss when to reference the § 192.712 process for crack anomaly response and repair.

(3) ***<u>PHMSA should minimize changes to § 192.619, which apply to all gas pipelines.</u>***

In proposed § 192.619(e), PHMSA appears to restate the applicability and required methods to complete MAOP reconfirmation, which are already addressed in § 192.624. In proposed § 192.619(f), PHMSA appears to add a new recordkeeping requirement that would apply to all gas pipelines (transmission, distribution and gathering). The language in § 192.619(f) is confusing, and could be interpreted to mean that even if an operator has a TVC record of a pressure test, the operator still needs to reconfirm MAOP (e.g., conduct another pressure test) if the unrelated data (e.g., inspection data) does not exist. Requirements to perform MAOP reconfirmation and maintain records generated during MAOP reconfirmation are outlined in § 192.624; restating these in § 192.619 only creates confusion and unintended consequences.[25] PHMSA should withdraw its proposed changes to §§ 192.619(e)-(f).

One minor modification to § 192.619 is warranted. PHMSA should clarify in § 192.619(a) that compliance with any of the six methods to reconfirm MAOP in § 192.624 satisfies the § 192.619 requirement for a pressure test record, consistent with the December GPAC meeting slide deck.[26] One of the triggers that require MAOP reconfirmation under § 192.624(a)(2) is the inability to produce TVC records of a pressure test for pipelines installed after 1970 as outlined in § 192.517(a). If an operator reconfirms MAOP using a method other than pressure testing (e.g., ECA), it may not have a pressure test record. PHMSA will remove ambiguity by providing the Associations' recommended clarification in § 192.619(a).

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[25] Member Drake (12/15/17 transcript, page 67): "With all the energy you're putting into 624, is it appropriate to consider leaving, you know, making more changes to 619? I think 624 actually deals with this issue. And I think you may be in a place where you can leave 619 alone, because you're dealing with the problem here."
[26] PHMSA Slide 76, December 2017 GPAC Meeting: "Operators may choose any of the 6 allowed methods to reconfirm MAOP."

B. Proposed Changes to § 192.619 and § 192.624: GPAC Discussion and Public Comments

The Associations provide the following suggested modifications to PHMSA's proposed §192.619 and § 192.624. The Associations believe the modifications shown in **red** reflect PHMSA's proposed modifications as presented in the slide deck for the December GPAC meeting. The Associations also suggest the modifications shown in **blue** to the PHMSA proposed regulatory language, based on the GPAC discussions and public comment during the June 2017 meeting:

§ 192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure determined under paragraph (c) or (d) of this section **or under §192.624**, or the lowest of the following:

PHMSA must clarify in § 192.619(a) that pipe segments that complete § 192.624 have a valid MAOP.

(1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part. However, for steel pipe in pipelines being converted under §192.14 or uprated under subpart K of this part, if any variable necessary to determine the design pressure under the design formula (§192.105) is unknown, one of the following pressures is to be used as design pressure:

(i) Eighty percent of the first test pressure that produces yield under section N5 of Appendix N of ASME B31.8 (incorporated by reference, *see* §192.7), reduced by the appropriate factor in paragraph (a)(2)(ii) of this section; or

(i) If the pipe is 12¾ inches (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa).

(5) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:

(i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.

(ii) For steel pipe operated at 100 p.s.i. (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the following table:

Class location	Factors[1], segment—			
	Installed before (Nov. 12, 1970)	Installed after (Nov. 11, 1970) and before (Date of New Rule)	Installed after (Date of New Rule – 1 Day)	Converted under §192.14
1	1.1	1.1	1.25	1.25
2	1.25	1.25	1.25	1.25
3	1.4	1.5	1.5	1.5
4	1.4	1.5	1.5	1.5

[1]For offshore segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

(6) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

Pipeline segment	Pressure date	Test date
—Onshore gathering line that first became subject to this part (other than §192.612) after April 13, 2006 but before (***insert effective date of the rule)*** —Onshore gathering line that first became subject to this part (other than §192.612) on or after (***insert effective date of the rule)*** —Onshore transmission line that was a gathering line not subject to this part before March 15, 2006	March 15, 2006, or date line becomes subject to this part, whichever is later ***(Insert date that is one year after the effective date of the rule),*** or date line becomes subject to this part, whichever is later. March 15, 2006, or date line becomes subject to this part, whichever is later.	5 years preceding applicable date in second column.
Offshore gathering lines	July 1, 1976	July 1, 1971.
All other pipelines	July 1, 1970	July 1, 1965.

(4) The pressure determined by the operator to be the maximum safe pressure after considering, material records, including material properties identified in accordance with §192.607, **if applicable,** and the history of the segment, particularly known corrosion and the actual operating pressure.

Per PHMSA Dec. GPAC slide 69, "PHMSA supports…adding 'if applicable' after the reference to §192.607 in § 192.619(a)(4).

(b) No person may operate a segment to which paragraph (a)(4) of this section is applicable, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with §192.195.

(c) The requirements on pressure restrictions in this section do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with §192.611.

(d) The operator of a pipeline segment of steel pipeline meeting the conditions prescribed in §192.620(b) may elect to operate the segment at a maximum allowable operating pressure determined under §192.620(a).

(e) ~~Notwithstanding the requirements in paragraphs (a) through (d) above, onshore steel transmission~~

The addition of § 192.619(e) should be removed as it only creates confusion. § 192.624 establishes which segments are in scope for MAOP reconfirmation and describes the methods.

~~pipelines that meet the criteria specified in § 192.624(a) must establish and document the maximum allowable operating pressure in accordance with § 192.624. using one or more of the following:~~

~~(1) Method 1: Pressure Test - Pressure test in accordance with § 192.624(c)(1)(i) or spike hydrostatic pressure test in accordance with § 192.624(c)(1)(ii), as applicable;~~

~~(2) Method 2: Pressure Reduction - Reduction in pipeline maximum allowable operating pressure in accordance with § 192.624(c)(2);~~

~~(3) Method 3: Engineering Critical Assessment – Engineering assessment and analysis activities in accordance with § 192.624(c)(3);~~

~~(4) Method 4: Pipe Replacement - Replacement of the pipeline segment in accordance with § 192.624(c)(4);~~

~~(5) Method 5: Pressure Reduction for Segments with Small PIR and Diameter - Reduction of maximum allowable operating pressure and other preventive measures for pipeline segments with small PIRs and diameters, in accordance with § 192.624(c)(5); or~~

~~(6) Method 6: Alternative Technology - Alternative procedure in accordance with § 192.624(c)(6).~~

Per slide #70 from December 2017 GPAC meeting, PHMSA supports shortening § 192.624(e), but the Associations contend that § 192.624(e) should be completely removed to avoid duplication with §

~~(f) Operators must maintain all records necessary to establish and document the MAOP of each pipeline as long as the pipe or pipeline remains in service. Records that establish the pipeline MAOP, include, but are not limited to, design, construction, operation, maintenance, inspection, testing, material strength, pipe wall thickness, seam type, and other related data. Records must be reliable, traceable, verifiable, and complete.~~

PHMSA should remove proposed § 192.619(f). As proposed, this would apply to distribution pipelines, which are outside the scope of this rulemaking. § 192.624(f) establishes the recordkeeping requirement associated with MAOP reconfirmation for transmission pipelines. Furthermore, § 192.619(f) could be interpreted to mean that additional actions are required even if TVC pressure test records exist.

§ 192.624 Maximum allowable operating pressure verification: Onshore steel transmission pipelines.

(a) ***Applicable Locations.*** The operator of an onshore transmission pipeline segment that is operated at a hoop stress level of 30% of specified minimum yield strength or more and meeting any of the following conditions must establish the maximum allowable operating pressure using one or more of the methods specified in § 192.624(c)(1) through (6):

As discussed above, PHMSA should limit the applicability of § 192.624 to segments operating above 30% of SMYS, as pipelines operating below 30% of SMYS generally do not fail in the rupture mode.

(1) ~~The pipeline segment has experienced a reportable in-service incident, as defined in § 191.3, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a cracking-related defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spot, or stress corrosion cracking and the pipeline segment is located in one of the following locations:~~
  ~~(i) A high consequence area as defined in § 192.903;~~
  ~~(ii) A class 3 or class 4 location; or~~
  ~~(iii) A moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (i.e., "smart pigs").~~

> As discussed above, PHMSA should limit the applicability of § 192.624 to segments without records of a pressure test to subpart J test levels. Pipeline reportable incidents should be addressed as part of corrosion control, operations, maintenance, and integrity management, and anomaly response, but do not invalidate MAOP for the entire segment or pipeline.

(2) Pressure test records necessary to establish maximum allowable operating pressure per subpart J for the pipeline segment, including, but not limited to, records required by § 192.517(a), are not ~~reliable~~, traceable, verifiable, and complete and the pipeline is located in one of the following locations:
  (i) A high consequence area as defined in § 192.903; or
  (ii) A class 3 or class 4 location

(3) The pipeline segment maximum allowable operating pressure was established in accordance with § 192.619(c) of this subpart before ***[insert effective date of rule]*** and is located in one of the following locations ~~areas~~:
  (i) A high consequence area as defined in § 192.903;
  (ii) A class 3 or class 4 location; or
  (iii) A moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (i.e., "smart pigs").

> The Associations support MAOP reconfirmation for class 3 and four areas where MAOP is currently established per 192.619(c). However, PHMSA should note that the Congressional mandate in the 2011 Act was limited to pipelines in HCAs.

(b) ***Completion Date.*** For pipelines installed before **[*insert the effective date of rule*]**, all actions required by this section must be completed according to the following schedule:
  (1) The operator must develop and document a plan for completion of all actions required by this section by ***[insert date that is 1 year after the effective date of rule]***.
  (2) The operator must complete all actions required by this section on at least 50% of the mileage of locations that meet the conditions of § 192.624(a) by ***[insert date that is 8 years after the effective date of rule].***
  (3) The operator must complete all actions required by this section on 100% of the mileage of locations that meet the conditions of § 192.624(a) by ***[insert date that is 15 years after the effective date of rule].***
  (4) If operational and environmental constraints limit the operator from meeting the deadlines in § 192.614 (b)(2) and (3) above, the operator may petition for an extension of the completion deadlines by up to one year, upon submittal of a notification to the Associate Administrator of the Office of Pipeline Safety in accordance with paragraph (e). The notification must include an

up-to-date plan for completing all actions in accordance with (b)(1), the reason for the requested extension, current status, proposed completion date, remediation activities outstanding, and any needed temporary safety measures to mitigate the impact on safety.

(c) ***Maximum Allowable Operating Pressure Reconfirmation ~~Determination~~.*** The operator of a pipeline segment meeting the criteria in paragraph (a) above must reconfirm ~~establish~~ its maximum allowable operating pressure using one of the following methods:

(1) Method 1: Pressure test.

(i) Perform a pressure test in accordance with **Subpart J of this part** ~~192.505(c)~~. The maximum allowable operating pressure will be equal to the test pressure divided by the greater of either 1.25 or the applicable class location factor in § 192.619(a)(2)(ii) or § 192.620(a)(2)(ii).

~~(ii) If the pipeline segment includes legacy pipe or was constructed using legacy construction techniques or the pipeline has experienced an incident, as defined by § 191.3, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a crack or crack-like defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spot, or stress corrosion cracking, then the operator must perform a spike pressure test in accordance with § 192.506. The maximum allowable operating pressure will be equal to the test pressure specified in § 192.506(c) divided by the greater of 1.25 or the applicable class location factor in § 192.619(a)(2)(ii) or § 192.620(a)(2)(ii).~~

~~(iii) If the operator has reason to believe any pipeline segment may be susceptible to cracks or crack-like defects due to assessment, leak, failure, or manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph (d) of this section.~~

PHMSA should clarify that 192.624 outlines a process for *reconfirming* MAOP, not *determining* MAOP. All pipeline segments in operation have a current MAOP.

Per PHMSA Dec. GPAC slide 113, PHMSA proposes to "Revise 192.624(c)(1) to refer to Subpart J rather than 192.505(c)."

As discussed above, PHMSA should eliminate the requirement that operators use a spike test to reconfirm MAOP. Spike hydrostatic testing was developed for the targeted management of time-dependent linear defects – i.e., stress corrosion cracking (SCC). Spike testing imparts significant stresses on the pipeline, that introduce the risk of failures of piping and components that would otherwise pose no threat during the service life of the pipeline.

A single subpart J pressure test, or prior testing to subpart J pressure test levels, is a conservative and proven method to establish MAOP. Additional fracture mechanics modeling is inappropriate for the one-time reconfirmation of MAOP if a subpart J pressure test has been performed. As discussed above, fracture mechanics modeling is a valuable tool for calculating the failure pressure of cracks and crack-like defects as part of anomaly response and repair requirements following integrity assessments. Fracture mechanics modeling requirements should be moved to a new § 192.712, separate from MAOP reconfirmation.

(2) Method 2: Pressure Reduction - The pipeline maximum allowable operating pressure will be no greater than the highest actual operating pressure sustained by the pipeline from December 17, 2004 ~~during the 18 months preceding *[insert effective date of rule]*~~ divided by the greater of 1.25 or the applicable class location factor in § 192.619(a)(2)(ii) or § 192.620(a)(2)(ii). The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during a continuous 30-day period. The value used as the highest actual sustained operating pressure must account for differences between discharge and upstream pressure on the pipeline by use of either the lowest pressure value for the entire segment or using the operating pressure gradient (i.e., the location-specific operating pressure at each location).

If an operator has reduced a pipeline's MAOP during the time period since the implementation of the Gas Pipeline Integrity Management Regulation (Subpart O) on December 17, 2004 (e.g., for voluntary reasons, due to a class location change, etc.), then the reduction in MAOP should be considered as a Pressure Reduction in the new MAOP as determined under §192.624(c)(2) Method 2. In many instances, further reductions are not even possible if the pipeline is to continue serving its existing load.

(i) Where the pipeline segment has had a class location change in accordance with § 192.611 and pipe material and pressure test records are not available, the operator must reduce the pipeline segment MAOP as follows:

(A) For segments where a class location changed from 1 to 2, from 2 to 3, or from 3 to 4, reduce the pipeline maximum allowable operating pressure to no greater than the highest actual operating pressure sustained by the pipeline from December 17, 2004 ~~during the 18 months preceding *[insert effective date of rule]*~~ divided by 1.39 for class 1 to 2, 1.67 for class 2 to 3, and 2.00 for class 3 to 4.

(B) For segments where a class location changed from 1 to 3, reduce the pipeline maximum allowable operating pressure to no greater than the highest actual operating pressure sustained by the pipeline from December 17, 2004 ~~during the 18 months preceding *[insert effective date of rule]*~~ divided by 2.00.

~~(ii) If the operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects due to assessment, leak, failure, or manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the~~

As discussed above, a single subpart J pressure test, or prior testing to subpart J pressure test levels, is a conservative and proven method to establish MAOP. If an operator is using Method 2 with the factors prescribed in subpart J, the operations prior to the pressure reduction are functioning as a pressure test to subpart J test levels. As discussed above, the requirement for fracture mechanics modeling is inappropriate if an operator is reducing pressure using the subpart J factors.

The reference to subpart K and uprating here is unnecessary. There is nothing in 192.624 that suggests operators would not be able to in the future. By providing this reference in some, but not all, of the MAOP Verification methods, the regulations could be interpreted that uprating pursuant to Subpart K may not be a future option for some pipes.

~~pipeline in accordance with paragraph (d) of this section.~~

~~(iii) Future uprating of the segment in accordance with subpart K is allowed if the maximum allowable operating pressure is established using Method 2.~~

(ii) If an operator elects to use Method 2, but desires to use a less conservative pressure reduction factor, the operator must notify PHMSA in accordance with paragraph (e) of this section no later than seven calendar days after establishing the reduced maximum allowable operating pressure. The notification must include the following details:

(A) Descriptions of the operational constraints, special circumstances, or other factors that preclude, or make it impractical, to use the pressure reduction factor specified in § 192.624(c)(2);

(B) The fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis that complies with §192.712 ~~paragraph (d) of this section~~;

(C) Justification that establishing maximum allowable operating pressure by another method allowed by this section is impractical;

(D) Justification that the reduced maximum allowable operating pressure determined by the operator is safe based on analysis of the condition of the pipeline segment, including material records, material properties verified in accordance § 192.607, and the history of the segment, particularly known corrosion and leakage, and the actual operating pressure, and additional compensatory preventive and mitigative measures taken or planned.

(E) Planned duration for operating at the requested maximum allowable operating pressure, long term remediation measures and justification of this operating time interval, including fracture mechanics modeling for failure stress pressures and cyclic fatigue growth analysis per §192.712. ~~and other validated forms of engineering analysis that have been reviewed and confirmed by subject matter experts in metallurgy and fracture mechanics.~~

As discussed above, the Associations recommend that PHMSA establish a new § 192.712 to describe the fracture mechanics modeling process.

(3) Method 3: Engineering Critical Assessment - Conduct an engineering critical assessment and analysis (ECA) to establish the material strength ~~condition~~ of the segment and maximum allowable operating pressure. An ECA is an analytical procedure, based on assessment information, fracture mechanics principles, relevant material properties (mechanical and fracture resistance properties), and operating history., ~~operational environment, in-service degradation, possible failure mechanisms, initial and final defect sizes, and usage of future operating and maintenance procedures to determine the maximum tolerable sizes for imperfections. The ECA must assess: threats; loadings and operational circumstances relevant to those threats including along the right-of-way; outcomes of the threat assessment; relevant mechanical and fracture properties; in-service degradation or failure processes; initial and~~

As discussed above, the goal of the ECA method is to confirm material strength, similar to a pressure test. Therefore, PHMSA should remove the aspects of the proposed ECA that address the long-term management of various integrity threats. Instead, Method 3 should be an ILI-based methodology focused on assessing manufacturing and construction-related features to confirm material strength.

~~final defect size relevance. The ECA must quantify the coupled effects of any defect in the pipeline.~~

(i) *ECA analysis*.

(A) ~~The ECA must integrate and analyze the results of the material documentation program required by §192.607, if applicable, and the results of all tests, direct examinations, destructive tests, and assessments performed in accordance with this section, along with other pertinent information related to pipeline integrity, including but not limited to close interval surveys, coating surveys, and interference surveys required by subpart I, root cause analyses of prior incidents, prior pressure test leaks and failures, other leaks, pipe inspections, and prior integrity assessments, including those required by § 192.710 and subpart O.~~

(B) The ECA must analyze any cracks or crack-like manufacturing and construction defects remaining in the pipe~~, or that could remain in the pipe,~~ to determine the predicted failure pressure (PFP) of actionable anomalies per §192.712(b). ~~each defect. The ECA must use the techniques and procedures in Battelle Final Reports ("Battelle's Experience with ERW and Flash Weld Seam Failures: Causes and Implications" - Task 1.4), Report No. 13-002 ("Models for Predicting Failure Stress Levels for Defects Affecting ERW and Flash-Welded Seams" – Subtask 2.4), Report No. 13-021 ("Predicting Times to Failure for ERW Seam Defects that Grow by Pressure-Cycle-Induced Fatigue" – Subtask 2.5) and ("Final Summary Report and Recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures – Phase 1" – Task 4.5) (incorporated by reference, *see* § 192.7) or other technically proven methods including but not limited to API RP 579-1/ASME FFS-1, June 15, 2007, (API~~

The ECA method is composed of several analyses to confirm material strength, as outlined below. Different material properties are critical for each analysis method, as discussed above. Therefore, for clarity, PHMSA should list the material attributes needed for each analysis below, where each analysis is described. See recommended language in (B) and (C) below.

The ECA process should be focused on a one-time assessment of current features, as identified by inline inspection, that could affect material strength. Analysis of "any crack or crack-like manufacturing and construction defects remaining in the pipe" is appropriate and consistent with the requirements for analyzing metal loss defects. The reference to other defects "that could remain in the pipe" is confusing and unnecessary if an operator has run an ILI tool to identify cracks and crack-like defects currently in the pipe.

As discussed above, the Associations recommend that PHMSA establish a new §192.712(b) to describe the fracture mechanics modeling process. For consistency, the §192.712(b) process can be referenced as part of the ECA for MAOP, and also referenced elsewhere in Part 192 where fracture mechanics modeling is required. §192.712(c), analysis for flaw growth and remaining life, would not be necessary to support ECA for MAOP Reconfirmation, because the ECA is a one-time assessment of the current features, as identified by inline inspection, that could affect material strength.

~~579-1, Second Edition) – Level II or Level III, CorLas™, or PAFFC. The ECA must use conservative assumptions for crack dimensions (length and depth) and failure mode (ductile, brittle, or both) for the microstructure, location, type of defect, and operating conditions (which includes pressure cycling).~~ If diameter or wall thickness is not known or not adequately documented by traceable, verifiable, and complete records, then the operator must:

(1) Use data from comparable pipe with known properties and traceable, verifiable, and complete records; or

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

> For an ECA on a pipe segment without TVC records of certain material properties, the operator should be able to use known properties that are documented by TVC records on

If longitudinal joint factor is not known or not adequately documented by traceable, verifiable, and complete records, then the operator must:

(1) Use data from comparable pipe with known properties and traceable, verifiable, and complete records;

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

(3) Assume an "other" joint factor in accordance with §192.113.

If SMYS or actual material yield is not known or not adequately documented traceable, verifiable, and complete records, then the operator must:

(1) Use data from comparable pipe with known properties and traceable, verifiable, and complete records;

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

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

If actual material toughness is not known or not adequately documented by ~~**reliable**~~, traceable, verifiable, and complete records, then the operator must:

(1) Use data from comparable pipe with known properties and traceable, verifiable, and complete records;

(2) Verify the ~~determine a~~ Charpy v-notch toughness based upon the material documentation process ~~program~~ specified in § 192.607; or

(3) ~~u~~Use conservative values for Charpy v-notch toughness as follows: body toughness of less than or equal to **13** ~~**5**~~.0 ft-lb and seam toughness of less than or equal to **4** ~~**1**~~ ft-lb.

(C) The ECA must analyze any metal loss defects not associated with a

> Per PHMSA Dec. GPAC slide 97: "PHMSA: in IVP, operators may assume Grade A (30,000 psi or lower) if pipe grade is unknown for purposes of establishing MAOP."
>
> 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."

dent including corrosion, gouges, scrapes or other metal loss defects that could remain in the pipe to determine the predicted failure pressure (PFP). ASME/ANSI B31G (incorporated by reference, see § 192.7) or AGA Pipeline Research Committee Project PR–3–805 (“RSTRENG,” incorporated by reference, see § 192.7) must be used 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. The ECA must use conservative assumptions for metal loss dimensions (length, width, and depth). When determining PFP for gouges, scrapes, selective seam weld corrosion, crack-related defects, or any defect within a dent, appropriate failure criteria and justification of the criteria must be used. **If diameter or wall thickness is not known or not adequately documented by traceable, verifiable, and complete records, then the operator must:**

(1) **Use data from comparable pipe with known properties and traceable, verifiable, and complete records; or**

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

If longitudinal joint factor is not known or not adequately documented by traceable, verifiable, and complete records, then the operator must:

(1) **Use data from comparable pipe with known properties and traceable, verifiable, and complete records;**

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

(3) **Assume an “other” joint factor in accordance with §192.113.**

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:

(1) **Use data from comparable pipe with known properties and traceable, verifiable, and complete records;**

(2) a~~A~~ssume grade A **(30 ksi)** pipe; or

(3) **Verify these** ~~determine the material~~ properties based upon the material documentation **process** ~~program~~ specified in § 192.607.

The references to ultimate tensile strength for ECA calculations is inappropriate. Ultimate tensile strength is not required to analyze either metal loss or cracking/crack-like defects.

(D) The ECA must analyze interacting defects to conservatively determine the most limiting PFP for interacting defects. Examples include but are not limited to, cracks in or near locations with corrosion metal loss, dents with gouges or other metal loss, or cracks in or near dents or other deformation damage. The ECA must document all evaluations and any assumptions used in the ECA process.

(E) The maximum allowable operating pressure must be established **by dividing** ~~at~~ the lowest PFP for any known or postulated defect, or interacting defects, remaining in the pipe ~~divided~~ by the greater of 1.25 or the applicable factor listed in § 192.619(a)(2)(ii) or § 192.620(a)(2)(ii).

~~(ii) *Use of prior pressure test*. If pressure test records as described in subpart J and § 192.624(c)(1) exist for the segment, then an in-line inspection program is not required, provided that the remaining life of the most severe defects that could have survived the pressure test have been calculated. and a re-assessment interval has been established. The appropriate retest interval and periodic tests for time-dependent threats must be determined in accordance with the methodology in § 192.624(d) *Fracture mechanics modeling for failure stress and crack growth analysis*.~~

(iii) *In-line inspection*. If the segment does not have records for a pressure test in accordance with subpart J test levels and § 192.624(c)(1), the operator must develop and implement an inline inspection (ILI) program using tools that can detect wall loss, deformation from dents, wrinkle bends, ovalities, expansion, seam defects including cracking and ~~selective seam weld corrosion~~, longitudinal, circumferential and girth weld cracks, hard spot cracking, and ~~stress corrosion cracking~~. At a minimum, the operator must conduct an assessment using high resolution magnetic flux leakage (MFL) tool, a high resolution deformation tool, and ~~either~~ an electromagnetic acoustic transducer (EMAT), circumferential MFL (CMFL), helical MFL/spiral field (SMFL), or ultrasonic testing (UT) tool, or a combination of these tools.

(A) In lieu of the technologies and processes ~~tools~~ specified in paragraph § 192.624(c)(3)~~(i)~~, an operator may use "other technology or another process" if it is validated by a subject matter expert in metallurgy and fracture mechanics to produce an equivalent understanding of the condition of the pipe. If an operator elects to use "other technology or another process," it must notify the Associate Administrator of Pipeline Safety, at least 90 ~~180~~ days prior to use, in accordance with paragraph (e) of this

PHMSA should remove the "use of prior pressure test" alternative within the ECA. This allows the ECA process to be simplified and focused on a one-time assessment of current features, as identified by inline inspection, that could affect material strength. Method 1 already provides a pressure test method for reconfirming MAOP.

Even if a pressure test was conducted prior to the creation of subpart J, if there is a TVC record of a test to subpart J *test levels*, MAOP reconfirmation should not be required.

References to SSWC and SCC, which are time-dependent features, should be removed. These features are more appropriately managed as part of ongoing corrosion control, maintenance, anomaly response, and integrity management programs. MAOP reconfirmation is intended to identify manufacturing and construction features that may impact material strength, not time-dependent features.

Additionally, Circumferential MFL (CMFL) or helical MFL/spiral field (SMFL) should also be allowed as an ILI method for identifying manufacturing features. Operators have had success using CMFL for this purpose, similar to EMAT or UT.

Final December 2017 GPAC voting language: "Incorporate language stating that, if an operator does not receive an objection letter from PHMSA within 90 days of notifying PHMSA of an alternative sampling approach, the operator can proceed with their method. PHMSA will notify the operator if additional review time is needed."

section. If an operator does not receive an objection letter from PHMSA within 90 days of notifying PHMSA, the operator can proceed with the other technology or process. PHMSA will notify the operator within 90 days of the request if additional review time is needed. ~~and receive a "no objection letter" from the Associate Administrator of Pipeline Safety prior to its usage.~~ The ~~"other technology"~~ notification must have:

(1) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments including characterization of defect size crack assessments (length, depth, and volumetric); and

(2) Procedures and processes to conduct tests, examinations, and assessments, perform evaluations, analyze defects and remediate defects discovered.

~~(B) If the operator has information that indicates a pipeline includes segments that might be susceptible to hard spots based on assessment, leak, failure, manufacturing vintage history, or other information, then the ILI program must include a tool that can detect hard spots.~~

~~(C) If the pipeline has had a reportable incident, as defined in § 192.3, attributed to a girth weld failure since its most recent pressure test, then the ILI program must include a tool that can detect girth weld defects unless the ECA analysis performed in accordance with paragraph § 192.624(c)(3)(iii) includes an engineering evaluation program to analyze the susceptibility of girth weld failure due to lateral stresses.~~

The integrity concern related to hard spots is that hard spots can result in cracking on in-service pipelines. The proposed ECA process already requires operators to assess for cracks. Identifying hard spots to anticipate future cracking may be a maintenance and integrity management concern, but is not appropriate as part of one-time MAOP reconfirmation.

As discussed above, pipeline reportable incidents should be addressed as part of corrosion control, operations, maintenance, integrity management, and anomaly response, but do not invalidate MAOP for the entire segment or pipeline.

(D) Inline inspection must be performed in accordance with § 192.493.

(E) The operator must use unity plots or equivalent methodologies to demonstrate the effectiveness of the inline inspection tools in identifying and sizing actionable manufacturing and construction-related anomalies. The operator must have a process for identifying outliers and addressing outliers through conducting additional in-field examinations, reanalyzing inline inspection data, or both. ~~All MFL and deformation tools used must have been validated to characterize the size of defects within 10% of the actual dimensions with 90% confidence. All EMAT or UT tools must have been validated to characterize the size of cracks, both length and depth, within 20% of the actual dimensions with 80% confidence, with like-similar analysis from prior tool runs done to ensure the results are consistent with the required corresponding hydrostatic test pressure for the segment being evaluated.~~

(F) ~~Interpretation and evaluation of assessment results must meet the requirements of §§ 192.710, 192.713, and subpart O, and~~ Operators must develop procedures to conservatively account for the accuracy and reliability of ILI, in-the-ditch examination methods and tools, and any other assessment and examination results used to determine the actual sizes of cracks, metal loss, deformation and other defect dimensions. ~~by applying the most conservative limit of the tool tolerance specification~~. ~~ILI and in-the-ditch examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards confirmed for accuracy through confirmation tests for the type defects and pipe material vintage being evaluated.~~ Inaccuracies must be accounted for in the procedures for evaluations and fracture mechanics models for predicted failure pressure determinations.

> Tool tolerances vary by vendor and technology and will change with time. Rather than require specific confidence intervals, PHMSA should require operators to use unity plots or equivalent methodologies to demonstrate the effectiveness of the inline inspection tools in identifying and sizing actionable manufacturing and construction-related anomalies. Operators should be required to develop procedures to conservatively account for the accuracy and reliability of ILI, in-the-ditch examination methods and tools, and any other assessment and examination results.
>
> The reference to integrity management and anomaly response sections for interpreting and evaluating assessment results in (F) is confusing and unnecessary; requirements for analyzing manufacturing and construction features identified through the ECA ILI are sufficiently addressed in 192.624(c)(3).

(G) Anomalies detected by ILI assessments must be repaired in accordance with applicable repair criteria in §§ 192.713 and 192.933.

(iv) ~~If the operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects due to assessment, leak, failure, or manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph § 192.624(d).~~

> 192.624(c)(3)(iv) should be removed, as it is duplicative and confusing. Fracture mechanics modeling requirements for ECA are already outlined above.

(2) Method 4: Pipe Replacement - Replace the pipeline segment.

(3) Method 5: Pressure Reduction for Segments with Small Potential Impact Radius and Diameter – Pipelines with a maximum allowable operating pressure less than 30 percent of specified minimum yield strength, a potential impact radius (PIR) less than or equal to 150 feet, nominal diameter equal to or less than 8-inches, and which cannot be assessed using inline inspection or pressure test, may establish the maximum allowable operating pressure **by performing the actions in either (i) or (ii) as listed below:** ~~as follows:~~

(i) Reduce the pipeline maximum allowable operating pressure to no greater than the highest actual operating pressure sustained by the pipeline **from December 17, 2004** ~~during the 18 months preceding *[insert effective date of rule]*~~, divided by 1.1. The highest actual sustained pressure must have been reached for a minimum cumulative duration of eight hours during one continuous 30-day period. The reduced maximum allowable operating pressure must account for differences between discharge and upstream pressure on the pipeline by use of either the lowest value for the entire segment or the operating pressure gradient (i.e., the location specific operating pressure at each location);

(ii) **Perform the following additional actions to ensure the safety of the pipeline:**

(A) Conduct external corrosion direct assessment in accordance with § 192.925, and internal corrosion direct assessment in accordance with § 192.927;

(B) Develop and implement procedures for conducting non-destructive tests, examinations, and assessments for cracks and crack-like defects, including but not limited to stress corrosion cracking, selective seam weld corrosion, girth weld cracks, and seam defects, for pipe at all excavations associated with anomaly direct examinations, in situ evaluations, repairs, remediations, maintenance, or any other reason for which the pipe segment is exposed, except for segments exposed during excavation activities that are in compliance with § 192.614;

As noted above, the Associations recommend that PHMSA limit the applicability of 192.624 to transmission pipelines operating above 30% SMYS. This would eliminate the need for Method 5. However, if PHMSA does not limit the applicability of 192.624, changes are needed to make Method 5 practicable.

PHMSA should allow operators of low-risk pipelines to perform a 10% pressure reduction *OR* implementation of reasonable P&M measures. PHMSA's proposed Method 5 for low-risk pipelines is significantly more burdensome than Method 2, "Pressure Reduction," and goes significantly beyond existing regulatory requirements.

See comments of Member Worsinger (12/15/17 transcript, page 62): "I think we're missing something….That we're taking the smallest diameter pipelines here, the ones with the least risk, and we're requiring additional, we're requiring more actions on that than we are on the larger diameter, those operating over 30% SMYS."

See comments of Member Allen (12/15/17 transcript, page 50): "as a state regulator it would be easier to enforce an 'or,' rather than an 'and.'…there could be a pretty significant amount of effort that goes into complying with this rule. And perhaps not enough customers to spread those costs over….likewise, with the municipal operators. They have to go to their Town Councils and try to come up with, you know, the tax to go ahead and, or the rates to go ahead and pay for that. And there's gone to be a lot of pushback."

(C) Conduct monthly patrols in Class 1 and 2 locations, at an interval not to exceed 45 days; weekly patrols in Class 3 locations not to exceed 10 days; and semi-weekly patrols in Class 4 locations, at an interval not to exceed six days, in accordance with § 192.705;

(D) Conduct monthly, instrumented leakage surveys in Class 1 and 2 locations, at intervals not to exceed 45 days; weekly leakage surveys in Class 3 locations at intervals not to exceed 10 days; and semi-weekly leakage surveys in Class 4 locations, at intervals not to exceed six days, in accordance with § 192.706; and

(E) Odorize gas transported in the segment, in accordance with § 192.625;

(F) If the operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects due to assessment, leak, failure, or manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with § 192.712. ~~paragraph § 192.624(d).~~

~~(iii) Under Method 5, future uprating of the segment in accordance with subpart K is allowed.~~

(4) Method 6: Alternative Technology or Process - Operators may use an alternative technical evaluation process that provides a sound engineering basis for verifying ~~establishing~~ maximum allowable operating pressure. If an operator elects to use ~~alternative~~ other technology or another process, the operator must notify PHMSA at least 90 ~~180~~ days in advance of use in accordance with paragraph § 192.624(e) of this section. If an operator does not receive an objection letter from PHMSA within 90 days of notifying PHMSA, the operator can proceed with the other technology or process. PHMSA will notify the operator within 90 days of the request if additional review time is needed. ~~The operator must submit the alternative technical evaluation to PHMSA with the notification , and obtain a "no objection letter" from the Associate Administrator of Pipeline Safety prior to usage of alternative technology.~~ The notification must include the following details:

(i) Descriptions of the technology or technologies to be used for tests, examinations, and assessments, establishment of material properties, and analytical techniques, with like-similar analysis from prior tool runs done to ensure the results are consistent with the required corresponding hydrostatic test pressure for the segment being evaluated.

(ii) Procedures and processes to conduct tests, examinations, and assessments, perform evaluations, analyze defects and flaws, and remediate defects discovered;

~~(iii) Methodology and criteria used to determine reassessment period or need for a reassessment including references to applicable regulations from this Part and industry standards;~~

~~(iv) Data requirements including original design, maintenance and operating history, anomaly or flaw characterization;~~

> As proposed, the list of details to be included in the Method 6 notification is unclear, excessive, and duplicative. The goal of Method 6 is to confirm material strength, similar to a pressure test but using an alternative technology or process. Therefore, PHMSA should remove the aspects related to the long-term management of various integrity threats. Detailed descriptions of the alternative technology/process, detailed procedures for tests and assessments, a discussion of criteria for establishing MAOP, and documentation requirements provide ample information for PHMSA to determine whether it has an objection to an operator's proposal.

(v) ~~Assessment techniques and acceptance criteria, including anomaly detection confidence level, probability of detection, and uncertainty of PFP quantified as a fraction of specified minimum yield strength;~~

(vi) ~~If the operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects due to assessment, leak, failure, or manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph § 192.624(d);~~

(vii) ~~Remediation methods with proven technical practice;~~

(viii) ~~Schedules for assessments and remediation;~~

(ix) ~~Operational monitoring procedures;~~

(x) Methodology and criteria used to justify and establish the maximum allowable operating pressure; and

(xi) Documentation requirements for the operator's process, including records to be generated.

(d) ~~*Fracture mechanics modeling for failure stress and crack growth analysis.*~~ [The Associations recommend that 192.624(d) be moved to a new § 192.712– see below for recommended language].

(e) ***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.

(f) ***Records.*** Each operator must keep for the life of the pipeline ~~reliable~~, traceable, verifiable, and complete records of the investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions made in accordance with the requirements of this section after (*insert effective date of the rule*).

Adding a reference to the effective date in 192.624(f) would help clarify that this is a prospective requirement to retain records of the work completed in executing this part.

C. Proposed New Section 192.712 – Fracture Mechanics

§ 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.**

> Fracture mechanics modeling should not be required for pipelines with MAOPs under 30% of SMYS. As discussed above, the rare instances of ruptures on pipelines with MAOPs under 30% SMYS are generally caused by corrosion and outside forces. Fracture mechanics modeling is not used to assess these sorts of anomalies.
>
> On page 20813 of the FR notice of the Proposed Rule, PHMSA references a recent study that provides support for limiting the threshold to pipelines that operate at greater than 30% SMYS as follows: "The Kiefner/GTI report evaluated theoretical fracture models and supporting test data in order to define a possible leak-rupture threshold stress level. The report pointed out that 'no evidence was found that a propagating ductile rupture could arise from an incident attributable to any one of these causes in a pipeline that is operated at a hoop stress level of 30% of SMYS or less."

(1) **If actual material toughness is not known or not adequately documented for fracture mechanics modeling for failure stress pressure, the operator must:**

(i) **Use Charpy energy values from comparable pipe with known properties;**

(ii) **Use a conservative Charpy energy value to determine the toughness based upon the material documentation process specified in § 192.607;**

(iii) **Use 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) **Use 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 actual material strength is not known, 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 in metallurgy and fracture mechanics 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 hydro test pressure, the operator must:

(i) Use Charpy energy values from comparable pipe with known properties;

(ii) Use a conservative Charpy energy value to determine the toughness based upon the material documentation process specified in § 192.607;

(iii) Use a full size equivalent Charpy upper-shelf energy level of 120 ft-lb; or

(iv) Use 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 hydro 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 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.

"BMT Fleet Technologies, Fatigue Considerations for Natural Gas Transmission Pipelines, Reference 30348.DFR, June, 2016" is an auditable process that operators can apply for

IV. Strengthened Assessment Methods

A. General Comments: Spike Testing

The GPAC spent several hours on December 15th discussing various issues related to PHMSA's proposed spike pressure test requirements. The GPAC recognized the importance of spike testing as an assessment tool exposing significant time-dependent linear defects. Environmentally-related cracking, including stress corrosion cracking (SCC) has been identified as the only significant time-dependent linear defect threat on gas pipelines. However, public commenters and GPAC members expressed concerns about the applicability of spike tests to other threats and the limiting constraints of the procedural requirements. The Associations have summarized three key issues address during the GPAC meeting:

(1) ***PHMSA should establish minimum pressure testing requirements and hold times for spike pressure tests to ensure no unintended consequences to safety and affordability - §192.506(e)***

PHMSA currently proposes in §192.506(e) to require a minimum spike pressure test of 1.50 times Maximum Allowable Operating Pressure (MAOP) or 105% Specified Minimum Yield Strength (SMYS) and a hold time of 30 minutes. Both public commenters and GPAC members expressed concerns about these criteria. Holding a minimum pressure of 105% SMYS for 30 minutes can grow sub-critical defects and create issues that did not exist prior to the hydrostatic pressures test.[27] Furthermore, the Associations would like to remind PHMSA of the 2004 report by DOT/RSPA that recommended a minimum spike hydrostatic test pressure (STP) of 1.39 times MOP, which equates to 100% SMYS for pipelines operating at 72% SMYS. [28] The same study showed, and PHMSA acknowledged[29], that there is minimal difference in spike hydrostatic test effectiveness for holds of 30 minutes as compared to 15 minutes. The study concludes, "*A hold-time of only a few minutes is sufficient to prove integrity of a pipeline.*"

With the minimum test levels proposed by PHMSA, the range between the minimum and maximum test pressures is very narrow. This narrow test window combined with elevations over the test segment will lead to multiple test segments in areas with relatively minor evaluation differences. This does not appear to be accounted for in PHMSA's Preliminary Regulatory Impact Analysis. Utilizing a minimum spike hydrostatic test pressure of the lesser of either 1.50 times MAOP or 100% SMYS would increase the mileage that can be tested in a single test where elevation is a factor and would minimize the risk to pipe integrity.[30]

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[27] Regarding minimum spike hydrostatic test pressure and hold time:

- Member Drake (12/15/2017 Transcript, pg. 117): "…the last thing you want to do is hold that pressure for very long, because what ends up happening is you start growing sub-critical time dependent defects….That's where you actually create all these things of making this situation actually worse…ten minutes is a little bit more of an industry standard. It really is just trying to avoid an unintended consequence."

[28] Baker, Michael Jr. Inc. TTO Number 6 - Spike Hydrostatic Test Evaluation, for the US Department of Transportation, Research and Special Projects Administration, July 2004, p. 57.

[29] Regarding spike hydrostatic test hold time:

- Mr. Nanny (12/15/2017 Transcript, pg. 129): "…I've seen research anywhere from ten minutest, fifteen minutes to an hour. The latest that we got on the low frequency ERW is that there's not much difference in the 15 minutes to an hour, or the 30 minutes to an hour…"

[30] Regarding spike hydrostatic test segmentation:

At both the GPAC members' and the public commenters' request, PHMSA has agreed to consider decreasing the minimum STP to the lesser of 1.50 times MAOP or 100% SMYS.[31] Additionally, PHMSA should decrease the spike pressure test hold times to 15 minutes, as supported by the DOT/RSPA study, to reduce the probability of growing subcritical defects.

(2) ***<u>PHMSA should limit the applicability of spike hydrostatic test assessment method to time dependent linear defects, such as stress corrosion cracking - §192.506(a)</u>***

PHMSA currently proposes language in §192.506(a) and 192.921(a)(3) that seems to indicate a broad application of spike hydrostatic tests. As discussed at the GPAC meeting, spike hydrostatic tests are an effective and practical method for assessing significant time-dependent linear defects. Environmentally-related cracking including stress corrosion cracking (SCC) has been identified as the only significant time-dependent linear defect threat on gas pipelines. Other assessment methods are available to assess manufacturing and other defect threats.[32]

(3) ***<u>PHMSA should allow pneumatic spike tests - §192.506(e)</u>***

PHMSA currently proposes to allow only hydrostatic spike tests. However, current pipeline safety regulations allow for pneumatic testing as long as the test pressure remains below a specified level (See §192.503(c)). The Associations acknowledge that there are safety concerns with utilizing natural gas as the testing medium. However, PHMSA has provided no independent technical justification for requiring only hydrostatic tests, instead of pneumatic pressure tests, which are safe to perform at the pressure levels PHMSA currently requires. For example, the Associations suggest that a pipeline currently operating at a very low percent SMYS in a Class 3 location should be permitted to use a pneumatic test to perform the spike test so long as the maximum hoop stress experienced by the pipeline is no greater than 50% SMYS, as provided for in 49 CFR 192.503(c).

Additionally, there are some advantages to other test media, such as the utilization of natural gas as the test media. For example, from a 2012 Kiefner and Associates report[33]:

- Member Zamarin (12/15/2017 Transcript, pg 122): "…so if 110% is your max and 105% is your minimum, you only have 5 percent band within which to design a test section. And what that means is, you need more test sections."
- Mr. Osman (12/15/2017 Transcript, pg 115): "Dropping the minimum SMYS percentage from 105 percent to 100 percent, while the minimum impact on the margin, but will drastically reduce the likelihood of pipe damage during the spike test and increase the mileage that could be included in a single test, therefore increasing the effectiveness of that tool."

[31] Mr. Nanny (12/14/2017 Transcript, pg. 154): "Now whether that should be 100-percent SMYS, or 105 or 1.39 times MAOP, which is for class 1 pipe 100-percent SMYS, PHMSA is opening to listening to everyone's comments there, and going back and taking a look at that, because we've looked at it a lot since the notice."

[32] Regarding applicability of spike hydrostatic test:

- Mr. Osman (12/15/2017 Transcript, pg. 115): "PHMSA should specifically address time dependent cracking as the threat managed by spike testing, such as stress corrosion cracking."
- Public comment (12/15/2017 Transcript, pg. 110): "…supported a spike hydro test only for time definite cracking threat, such as stress corrosion cracking. The requirement for spike hydrostatic testing for materials and construction related defects should be deleted. A pressure test to 1.25 MAOP for class 1 and 2, and 1.5 MAOP for 3 and 4 are adequate to address those threats."

[33] Haines, Harvey. Kiefer, John. Rosenfeld, Michael. "Study Questions Specified Hydrotest Hold Time's Value" Oil & Gas Journal. March 5, 2012

> *"Natural gas is already in the pipeline and the medium will therefore mimic the pressure profile of the pipeline in actual service. The density of the fluid will cause pressure to change with elevation, and using the same medium as will be used in service will exactly mimic the pressure variations occurring in service. This characteristic is especially advantageous in mountainous terrain, where elevation changes are extreme."*

The Associations have significant concerns regarding the inability to remove all water from transmission pipelines following a hydrostatic pressure test due to valves, bends, offshoots, and other obstacles. Therefore, the Associations propose to incorporate language to allow for pneumatic spike pressure tests to be used when safe and allowed by current regulations.

B. Proposed Changes to §192.506: Incorporation of GPAC Discussion and Public Comments

The GPAC has yet to vote on the proposed section §192.506. In advance of the next GPAC meeting, the Associations suggest the following modifications to the PHMSA proposed regulatory language (in blue below) based upon the GPAC discussions and public comment during the December 2017 meeting:

§192.506 Transmission Lines: Spike ~~hydrostatic~~ pressure test for existing steel pipe with integrity threats

a) Each segment of an existing steel pipeline that is operated at a hoop stress level of 30% of specified minimum yield strength or more and has been found to have time-dependent cracking, including stress corrosion cracking, must be strength tested by a spike hydrostatic pressure test unless the operator addresses the integrity threat by other means, such as in-line inspection or direct assessment. ~~cannot be addressed in accordance with this section to substantiate the proposed maximum allowable operating pressure.~~

b) Operators must select a test medium consistent with 192.503(b)-(c). ~~The spike hydrostatic pressure test must use water as the test medium.~~

c) The baseline test pressure ~~without the additional~~ to be applied after the spike test ~~pressure~~ is the test pressure specified in §§ 192.619(a)(2), or 192.620(a)(2), ~~or 192.624,~~ whichever applies.

d) The test must be conducted by maintaining the pressure at or above the baseline test pressure for at least 8 hours, with sound engineering analysis or leak surveys to account for changes that occur to test pressure, temperature and volume during the test ~~as specified in § 192.505(e)~~.

e) After the test pressure stabilizes at the baseline pressure and within the first two hours of the 8-hour test interval, the ~~hydrostatic~~ pressure must be raised (spiked) to a minimum of the lesser of 1.50 times MAOP or ~~105%~~ 100% SMYS. This spike ~~hydrostatic~~ pressure test must be held for at least ~~30~~ 15 minutes.

f) ~~If the integrity threat being addressed by the spike test is of a time-dependent nature such as a cracking threat, t~~ The operator must establish an appropriate retest interval and conduct periodic retests at that interval using the same spike test pressure or other assessment that addresses the threat. The appropriate retest interval and periodic tests for the time-dependent threat must be determined in accordance with the methodology in § 192.712 ~~624(d)~~.

> As discussed above, PHMSA should limit the applicability of spike hydrostatic test assessment method to time-dependent cracking.

> As discussed above, PHMSA should consider spike hydrostatic test alternatives - Allow pneumatic spike tests per 192.503(b)-(c).

> Spike test is strength test, not leak test. A pipe can pass assessment criteria with minimal leakage. Identifiable leaks should be repaired and retested. If leakage is evident on a pressure chart and cannot be found in the line pipe, this is appropriate place for instrumented leak survey.

> As discussed above, PHMSA should evaluate minimum pressure and hold time for spike hydrostatic pressure tests to ensure no unintended consequences to safety and affordability. Per Mr. Nanney (12/15/2017 Transcript, pg 228-229): "PHMSA will adjust the language of this section to consider different spike test parameters and time intervals…"

> See previous comments regarding moving fracture mechanics modeling to a new § 192.712.

g) Alternative Technology or Alternative Technical Evaluation Process - Operators may use alternative technology or an alternative technical evaluation process that provides a sound engineering basis for establishing a spike ~~hydrostatic~~ pressure test or equivalent. If an operator elects to use alternative technology or an alternative technical evaluation process, the operator must notify PHMSA at least ~~180~~ 90 days in advance of use in accordance with paragraph §192.624(e) of this section. If an operator does not receive an objection letter from PHMSA within 90 days of notifying PHMSA, the operator can proceed with the other technology or process. PHMSA will notify the operator within 90 days of the request if additional review time is needed. ~~The operator must submit the alternative technical evaluation to the Associate Administrator of Pipeline Safety with the notification and must obtain a "no objection letter" from the Associate Administrator of Pipeline Safety prior to usage of alternative technology or an alternative technical evaluation process.~~ The notification must include the following details:

Per voting slide for Strengthening IM Assessment methods, bullet 2 – Revise the "no objection" process as recommended by members at GPAC per the recommended procedure under §192.607…

As proposed, the list of details to be included in the notification is unclear, excessive, and duplicative. §192.506 provides a process for performing spike testing; remediation methods and fracture mechanics modeling requirements are addressed elsewhere. Detailed descriptions of the alternative process/technology, procedures for tests and assessments, data requirements, and subject matter expert review provides ample information for PHMSA to determine whether it has an objection to an operator's proposal.

(1) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments;
(2) Procedures and processes to conduct tests, examinations, and assessments, perform evaluations, analyze defects and flaws, and remediate defects discovered;
(3) Data requirements including original design, maintenance and operating history, anomaly or flaw characterization;
~~(4) Assessment techniques and acceptance criteria;~~
~~(5) Remediation methods for assessment findings;~~
~~(6) Spike hydrostatic pressure test monitoring and acceptance procedures, if used;~~
~~(7) Procedures for remaining crack growth analysis and pipe segment life analysis for the time interval for additional assessments, as required; and~~
(8) Evidence of a review of all procedures and assessments by a subject matter expert(s) in both metallurgy and fracture mechanics

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

Rather than refer to the "notifications" paragraph within the MAOP reconfirmation section, PHMSA should simply include notification instructions in this section for clarity.

(3) <u>Sending the notification to the Information Resources Manager by e-mail to InformationResourcesManager@dot.gov.</u>

(4) <u>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.</u>

C. General Comments: Modified Assessment Methods and Addition of New Assessment Methods

On December 15, the GPAC discussed PHMSA's proposal to expand and strengthen baseline assessment methods for integrity management (IM). The GPAC members were generally supportive of many of the changes to the assessment methods proposed by PHMSA, with the exception of a few points, but did express concerns about §192.921(a)(6). Rather than review the entirety of those discussions, the Associations offer the following comments concerning PHMSA's proposed limitation on the use of direct assessment.

PHMSA has proposed additional regulatory language which would limit the ability to use Direct Assessment (DA) for pipeline assessments unless all other assessment methods have been determined to be unfeasible or impractical. Public commenters and GPAC members expressed concern that it is unreasonable for PHMSA to write a regulatory requirement which rejects a valid and proven integrity assessment methodology and codify a preference of other methods. The Associations believe that each pipeline is unique in its operations, design, construction and maintenance. Therefore, the threats applicable to each pipeline are unique and how an operator chooses to assess these threats should also be unique. In addition, DA is a predictive tool that identifies areas where corrosion (ECDA for external corrosion; ICDA for internal corrosion; and SCCDA for stress corrosion cracking) could occur while other methods can only detect where corrosion has resulted in measurable metal loss.[34]

PHMSA refers to past incidents and "ongoing research and industry response to the [Advanced Notice of Proposed Rulemaking] ANPRM" to support emphasis on ILI technology and pressure testing. However, there is no industry study that would suggest DA does not work effectively to identify corrosion or cracking defects when the operator adheres to a technically-based DA procedure. This includes the pre-assessment and post-assessment steps, which validates that DA can be applied successfully to a particular pipe segment.[6]

The Associations also assert that the ECDA process can provide operators with a better understanding of critical conditions external to the pipeline, such as the effectiveness of cathodic protection (CP), coating condition, and the environment around the pipe. ECDA is predictive and helps to identify trends in low CP along the entire pipeline and in the pre-assessment, integrate this with soils, coating condition and other pertinent data. This helps operators identify potential issues and apply preventative remediation to avoid future external corrosion conditions. ILI provides an understanding of the existing metal loss conditions without reference to the external corrosion control trends that could lead to future corrosion along the pipeline. ECDA also is very accurate and cost effective in identifying injurious coating holidays which can

[34] Regarding limiting usage of DA:

- Ms. Byrnes (12/15/2017 Transcript, pg. 93): "ECDA is a four-step process which includes pre-assessment using knowledge about the pipeline and the history of the pipeline, historical data, feasibility, survey records, indirect inspection using highly accurate and sensitive inspection tools to do overland inspection of the entire segment…And then a post-assessment, which includes analysis of data collected to assess the effectiveness of ECDA and to determine reassessment intervals."
- Mr. Kivela (12/15/2017 Transcript, pg. 88): "When it comes to stress corrosion cracking, direct assessment, as was commented yesterday, (is) a very valid tool for screening lines that have never experienced stress corrosion cracking before, but they are susceptible to that threat."
- Member Drake (12/15/2017 Transcript, pg. 95): "The SCCDA in my opinion is working more reliably than in my inspection tools on DA for gas pipelines."

help operators identify trends in mechanical damage or other coating degradation issues. The Associations highly recommend that PHMSA consider the key benefits unique to DA and not limit its use.

PHMSA's proposed restrictions to the use of SCCDA are especially problematic.[35] SCCDA is often used as a screening tool to assess for SCC threat in gas pipelines when the basic criteria for SCC has been met per ASME B31.8S and there is no history of SCC on the pipeline. This is recognized in NACE SP 0204-2008, which PHMSA proposes to incorporate by reference. Based on the results of SCCDA, operators consider further ILI or pressure spike testing. A spike test or ILI should not be required where there is no history of SCC.

It should be noted that the determination of whether a pipeline is considered able to accommodate inspection by means of an instrumented in-line inspection tool is largely subjective and not well-defined. If promulgated, this rule would require an operator to continually demonstrate why a pipeline is not able to be inspected by ILI. Free-swimming, flow-driven ILI tools are often not compatible with intrastate transmission lines operated by LDCs for several reasons. Conditions must exist to assess a pipeline by ILI and obtain valid data: (1) constant and adequate flow to move the tool; (2) non-variable pressure conditions that may impact the valves, etc. (4) a redundancy in the system in the event of an abnormal operating condition; and (5) the ability to insert and remove the tool from the system.

For the reasons above, it is not appropriate for PHMSA to codify how an operator chooses its assessment methods for any threats, as long as methods are effective in identifying pipeline defects attributed to a particular threat.

[35] Regarding limiting the usage of SCCDA, see comments of Mr. Kivela and Member Drake above.

D. Proposed Changes to §192.921: GPAC Discussion and Public Comments

The GPAC has yet to vote on the proposed section §192.921. In advance of the next GPAC meeting, the Associations suggest the following modifications to the PHMSA proposed regulatory language (in **blue** below) based upon the GPAC discussions and public comment during the December 2017 meeting:

§192.921 How is the baseline assessment to be conducted?

(a) *Assessment methods.* An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods for each threat to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (*See* §192.917). In addition, an operator may use an integrity assessment to meet the requirements of this section if the pipeline segment assessment is conducted in accordance with the integrity assessment requirements of § 192.624(c) for establishing MAOP.

(1) Internal inspection tool or tools capable of detecting ~~corrosion, deformation and mechanical damage (including dents, gouges and groves), material cracking and crack-like defects (including stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, or any other~~ threats to which the covered segment is susceptible, <u>as determined by the operator</u>. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493. ~~A person qualified by knowledge, training, and experience~~ <u>An operator</u> must analyze the data obtained from an internal inspection tool to determine if a condition could adversely affect the safe operation of the pipeline. In addition, an operator must explicitly consider uncertainties in reported results (including, but not limited to, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies;

> Recommend PHMSA to clarify language so not to require all threats to be evaluated, rather to evaluate threats as identified by operator. Per Mr. McLaren (12/15/2017 Transcript pg. 109): "Clarify that every ILI assessment does not require crack tool, and that tools are driven to be identified or driven by the identified threats under 921(a)1 and 937(c)1. PHMSA's response is that the list of allowed methods in 921 does not drive with which methods must be used in any particular circumstance."

> Remove duplicative language per PHMSA (12/15/2017 Transcript pg. 108): "PHMSA agrees that the language in 192.921 regarding qualifications of persons is duplicative with existing code requirements in 192.915(b) and proposes to withdraw duplicative language."

(2) Pressure test conducted in accordance with subpart J of this part. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S, to justify an extended reassessment interval in accordance with §192.939. ~~The use of pressure testing is appropriate for threats such as internal corrosion, external corrosion, and other environmentally assisted corrosion mechanisms, including stress corrosion cracking, manufacturing and related defect threats, including defective pipe and pipe seams, selective seam weld corrosion, dents and other forms of mechanical damage~~;

It is unnecessary to prescriptively define the threats that can be addressed by a pressure test.

(3) "Spike" ~~hydrostatic~~ pressure test in accordance with § 192.506. The use of spike hydrostatic pressure testing is appropriate for time-dependent cracking threats, such as stress corrosion cracking;~~, selective seam weld corrosion, manufacturing and related defects, including defective pipe and pipe seams, and other forms of defect or damage involving cracks or crack-like defects;~~

As discussed above, spike hydrostatic tests are an effective and practical method for assessing significant time-dependent linear defects. Environmentally-related cracking including stress corrosion cracking (SCC) has been identified as the only significant time-dependent linear defect threat on gas pipelines.

(4) Excavation and *in situ* direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all threats, including but not limited to, ultrasonic testing (UT), radiography, and magnetic particle inspection (MPI);

(5) Guided Wave Ultrasonic Testing (GWUT) conducted as described in Appendix F;

(6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. ~~Use of direct assessment is allowed only if the line is not capable of inspection by internal inspection tools and is not practical to assess using the methods specified in paragraphs (d)(1) through (d)(5) of this section.~~ An operator must conduct the direct assessment in accordance with the requirements listed in §192.923 and with, as applicable, the requirements specified in §§192.925, 192.927 or 192.929;

As discussed above, PHMSA should allow operators to choose assessment methods based on effectiveness of methods to specific threat types.

(7) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator choosing this option must notify the Office of Pipeline Safety (OPS) ~~180~~ 90 days before conducting the assessment, in accordance with §192.949 ~~and receive a "no objection~~

Per voting slide for Strengthening IM Assessment methods bullet 2 – Revise the "no objection" process as recommended by members at GPAC per the recommended procedure under §192.607…

~~letter" from the Associate Administrator of Pipeline Safety.~~ If an operator does not receive an objection letter from PHMSA within 90 days of notifying PHMSA, the operator can proceed with the alternative method, tool, procedure or technique. PHMSA will notify the operator within 90 days of the request if additional review time is needed. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(b) *Prioritizing segments.* An operator must prioritize the covered pipeline segments for the baseline assessment according to a risk analysis that considers the potential threats to each covered segment. The risk analysis must comply with the requirements in §192.917.

(c) *Assessment for particular threats.* In choosing an assessment method for the baseline assessment of each covered segment, an operator must take the actions required in §192.917(e) to address particular threats that it has identified.

(d) *Time period.* An operator must prioritize all the covered segments for assessment in accordance with §192.917 (c) and paragraph (b) of this section. An operator must assess at least 50% of the covered segments beginning with the highest risk segments, by December 17, 2007. An operator must complete the baseline assessment of all covered segments by December 17, 2012.

(e) *Prior assessment.* An operator may use a prior integrity assessment conducted before December 17, 2002 as a baseline assessment for the covered segment, if the integrity assessment meets the baseline requirements in this subpart and subsequent remedial actions to address the conditions listed in §192.933 have been carried out. In addition, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe in the covered segment according to the requirements of §192.937 and §192.939.

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

(g) *Newly installed pipe.* An operator must complete the baseline assessment of a newly-installed segment of pipe covered by this subpart within ten (10) years from the date the pipe is installed. An operator may conduct a pressure test in accordance with paragraph (a)(2) of this section, to satisfy the requirement for a baseline assessment.

(h) *Plastic transmission pipeline.* If the threat analysis required in §192.917(d) on a plastic transmission pipeline indicates that a covered segment is susceptible to failure from causes other than third-party damage, an operator must conduct a baseline assessment of the segment in accordance with the requirements of this section and of §192.917. The operator must justify the use of an alternative assessment method that will address the identified threats to the covered segment.

E. Proposed Changes to §192.937: GPAC Discussion

Although PHMSA has not proposed to modify **§192.937** (*What is a continual process of evaluation and assessment to maintain a pipeline's integrity?*) in this rulemaking, PHMSA should consider the GPAC discussion around using an "other technology" and consider making adjustments to existing language in §192.937(c)(4) for consistency:

§192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

[…]

(c) *Assessment methods.*

[…]

(4) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) ~~180~~ **90** days before conducting the assessment, in accordance with §192.949. **If an operator does not receive an objection letter from PHMSA within 90 days of notifying PHMSA, the operator can proceed with the alternative method, tool, procedure or technique. PHMSA will notify the operator within 90 days of the request if additional review time is needed.** An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

F. Proposed Changes to §192.923: Incorporation of GPAC Votes

The GPAC voted to approve on the proposed section §192.922(c) with revisions "according to the recommendations by PHMSA staff at the meeting." The Associations recommend the following corrections (in **red** below) based upon the GPAC discussions and public comment during the December 2017 meeting:

§192.923 How is direct assessment used and for what threats?

a) *General.* An operator may use direct assessment either as a primary assessment method or as a supplement to the other assessment methods allowed under this subpart. An operator may only use direct assessment as the primary assessment method to address the identified threats of external corrosion (EC), internal corrosion (IC), and stress corrosion cracking (SCC).
b) *Primary method.* An operator using direct assessment as a primary assessment method must have a plan that complies with the requirements in—
    (1) Section 192.925 and ASME/ANSI B31.8S (incorporated by reference, see §192.7) section 6.4, and NACE SP0502 (incorporated by reference, *see* §192.7), if addressing external corrosion (EC).
    (2) Section 192.927, NACE SP0206-2006 if addressing internal corrosion (IC~~DA~~).
    (3) Section 192.929, NACE SP0204-2008 if addressing stress corrosion cracking (SCC~~DA~~).
c) *Supplemental method.* An operator using direct assessment as a supplemental assessment method for any applicable threat must have a plan that follows the requirements for confirmatory direct assessment in §192.931.

G. General Comments on Incorporation by Reference

The GPAC spent several hours on December 14th and 15th discussing the incorporation of various industry consensus standards into the regulations. The GPAC members were generally supportive of this proposal. However, many public commenters and GPAC expressed concerns about the proposed regulatory language of requiring operators to execute both "requirements and recommendations" within the industry consensus standards.

The Associations, in support of public comments and GPAC comments provided during the December meeting, would like to point out that recommended practices contain numerous provisions that use the term "shall" to denote a minimum requirement in order to comply with the RP. This is consistent with the use of the term "shall" in regulations. These documents also use non-mandatory terms such as "should," "may," or "can" to denote a recommendation that is advised, but not required, in order to conform to the RP.[36] This is also consistent with regulations, such as integrity management regulations, that require an operator to take certain actions based on the unique characteristics of the pipeline, the pipeline's operating parameters, and conditions around the pipeline. It should be noted that throughout the RPs, there are mandatory statements imposing broad obligations on operators prior to many non-mandatory provisions.

Historically, when incorporating consensus standards, PHMSA has stated only that the "requirements" of the consensus standard shall be followed. This allows the operator the flexibility to use other practices if a consensus standard recommendation is not practical or an operator has other practices that meet the intent of the "recommendation." However, in this circumstance, PHMSA states that operators would be required to meet both the "requirements *and recommendations*" of the incorporations by reference.

Consensus standards are written and approved by the subject matter experts who are members of the consensus organization and the process includes a public review of the draft standard, all following the ANSI standard approval process. In developing these standards, purposeful thought is provided on which provisions should be recommended and which should be required. Recommended provisions are those that are best in practice for specific situations, but that may not be appropriate to require broadly. Any changes to those established standards should be addressed through the organizations that develop these standards. If members of these organizations now know that it is PHMSA's desire to mandate all "should" statements, the Associations are concerned that consensus organizations will significantly reduce recommended statements in their standards, thus defeating the goal of having future meaningful consensus standards for the industry.

Based on the GPAC discussions and the additional information provided above, the associations recommend that PHMSA incorporate by reference the latest editions of the consensus standards as they

[36] Regarding incorporation of recommendations:

- Mr. Reynolds (12/15/2017 Transcript, pg. 85-86): "In regards to the consensus standards, or the incorporation by reference in PHMSA…I believe it's a change in its practice on previously incorporating...it has been that you shall follow the requirements….this particular rule, is now codifying that to incorporate that the operators are to required to follow the shall statements as well as the recommendations"
- Ms. Kurilla (12/15/2017 Transcript, pg. 151): "I personally am not super familiar with 0102, but if it is, in fact, is a list of best practices, by codifying both the recommendations and the requirements of documents that meant to be a best practices document, its kind of odd."

stand. If PHMSA believes non-mandatory provisions should be required, it should decide on the provisions that are important to the safety goal, provide justification or explanation to support the inclusion of these recommendations, and only adopt those specific provisions.

H. Proposed Changes to §192.150: Incorporation of the GPAC Votes, Discussion & Industry Comments

The GPAC voted to approve the language within §192.150 as proposed by PHMSA; however, the Associations suggest the following modifications (in **blue** below) to the PHMSA proposed regulatory language, which are based upon the GPAC discussions and public comment during the December 2017 meeting:

§192.150 Passage of internal inspection devices.

a) Except as provided in paragraphs (b) and (c) of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must be designed and constructed to accommodate the passage of instrumented internal inspection devices, in accordance with the requirements ~~and recommendations~~ in NACE SP0102-2010, Section 7 (incorporated by reference, see §192.7)

As discussed above, the Associations recommend that PHMSA refrain from making recommendations in consensus standards mandatory for operators. Per Chairman Danner (12/15/2017 Transcript pg. 157): "That the way that we've got it referenced and the way that it's actually written in the standard, it would be for them to consider. Its not mandatory because if you go and look at the standards, there's a bunch of should and mays…"

Per Mr. Mayberry: "If I may, what we're saying is we're going to address that and pretty much leave the standard as is where the shalls [are] shall, they will be expected. If it's a should it, they would need to consider it and if it's relevant they would do it, if not they wouldn't.

I. Proposed Changes to §192.493: Incorporation of GPAC Discussion and Public Comments

The GPAC has yet to vote on the proposed section §192.493. In advance of the next GPAC meeting, the Associations suggest the following modifications to the PHMSA proposed regulatory language (in **blue** below) based upon the GPAC discussions and public comment during the December 2017 meeting:

§192.493 In-line inspection of pipelines
When conducting in-line inspection of pipelines required by this part, each operator must comply with the requirements ~~and recommendations~~ of API STD 1163, *In-line Inspection Systems Qualification Standard;* ANSI/ASNT ILI-PQ-2005, *In-line Inspection Personnel Qualification and Certification;* and NACE SP0102-2010, *In-line Inspection of Pipelines* (incorporated by reference, see § 192.7). Assessments may also be conducted using tethered or remotely controlled tools, not explicitly discussed in NACE SP0102-2010, provided they comply with those sections of NACE SP0102-2010 that are applicable.

As discussed above, the Associations recommend that PHMSA refrain from making recommendations in consensus standards mandatory for operators. Per Chairman Danner (12/15/2017 Transcript pg. 157): "That the way that we've got it referenced and the way that it's actually written in the standard, it would be for them to consider. Its not mandatory because if you go and look at the standards, there's a bunch of should and mays…"

Per Mr. Mayberry: "If I may, what we're saying is we're going to address that and pretty much leave the standard as is where the shalls [are] shall, they will be expected. If it's a should it, they would need to consider it and if it's relevant they would do it, if not

J. Proposed Changes to §192.927: Incorporation of the GPAC Votes, Discussion & Industry Comments

The GPAC generally votes on concepts, rather than specific language, when reviewing the modified requirements for Internal Corrosion Direct Assessment (ICDA) in the Proposed Rule. The Associations provide the following modifications to proposed §192.927 for PHMSA's consideration. The Associations believe the modifications shown in **red** reflect the approved language as voted on at the December 2017 GPAC meeting. As discussed in these comments, the Associations have also identified additional concerns that were not voted on by the GPAC, shown in **blue**, but were shared during public comment or identified through written comments by the Associations on the Proposed Rule.

§192.927 What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?

(a) *Definition.* Internal Corrosion Direct Assessment (ICDA) is a process an operator uses to identify areas along the pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may reside, and then focuses direct examination on the locations in covered segments where internal corrosion is most likely to exist. The process identifies the potential for internal corrosion caused by microorganisms, or fluid with CO_2, O_2, hydrogen sulfide or other contaminants present in the gas.

(b) *General requirements.* An operator using direct assessment as an assessment method to address internal corrosion in a covered pipeline segment must follow the requirements in this section and in NACE SP0206-2006. The Dry Gas (DG) ICDA process described in this section applies only for a segment of pipe transporting nominally dry natural gas (see definition §192.3), not for a segment with electrolyte nominally present in the gas stream. If an operator uses ICDA to assess a covered segment operating with electrolyte present in the gas stream, the operator must develop a plan that demonstrates how it will conduct ICDA in the segment to effectively address internal corrosion, and must notify the Office of Pipeline Safety (OPS) 90 ~~180~~ days before conducting the assessment in accordance with §192.921 (a)(4) or §192.937(c)(4).

(c) *The ICDA plan.* An operator must develop and follow an ICDA plan that meets ~~all~~ the requirements ~~and recommendations~~ in NACE SP0206-2006 and that implements all four steps of the DG-ICDA process including pre-assessment, indirect inspection, detailed examination, and post-assessment. The plan must identify where all ICDA Regions with covered segments are located in the transmission system. An ICDA Region is a continuous length of pipe (including weld joints) uninterrupted by any significant change in water or flow characteristics that includes similar physical characteristics or operating history. An ICDA Region extends from the location where liquid may first enter the pipeline and encompasses the entire area along

> Per the GPAC Vote. PHMSA will revise the "no objection" process as recommended by members at the GPAC meeting per the recommended procedure under 192.607 and considering the other recommendations regarding the GWUT by members Drake and Zamarin"

> As discussed above, the Associations recommend that PHMSA refrain from making recommendations in consensus standards mandatory for operators. Per Chairman Danner (12/15/2017 Transcript pg. 157): "That the way that we've got it referenced and the way that it's actually written in the standard, it would be for them to consider. Its not mandatory because if you go and look at the standards, there's a bunch of should and mays…"
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> Per Mr. Mayberry: "If I may, what we're saying is we're going to address that and pretty much leave the standard as is where the shalls [are] shall, they will be expected. If it's a should it, they would need to consider it and if it's relevant they would do it, if not they wouldn't.

the pipeline where internal corrosion may occur until a new input introduces the possibility of water entering the pipeline. In cases where a single covered segment is partially located in two or more ICDA regions, the four-step ICDA process must be completed for each ICDA region in which the covered segment is partially located in order to complete the assessment of the covered segment.

(1) *Preassessment*. An operator must comply with the requirements ~~and recommendations~~ in NACE SP0206-2006 in conducting the preassessment step of the ICDA process.

(2) *ICDA region identification.* An operator must comply with the ~~requirements and recommendations~~ in NACE SP0206-2006, and the following additional requirements, in conducting the Indirect Inspection step of the ICDA process. Operators must explicitly document the results of its feasibility assessment as required by NACE SP0206-2006, Section 3.3; if any condition that precludes the successful application of ICDA applies, then ICDA may not be used, and another assessment method must be selected. When performing the indirect inspection, the operator must use pipeline specific data, exclusively. The use of assumed pipeline or operational data is prohibited. When calculating the critical inclination angle of liquid holdup and the inclination profile of the pipeline, the operator must consider the accuracy, reliability, and uncertainty of data used to make those calculations, including but not limited to gas flow velocity (including during upset conditions), pipeline elevation profile survey data (including specific profile at features with inclinations such as road crossing, river crossings, drains, valves, drips, etc.), topographical data, depth of cover, etc. The operator must select locations for direct examination, and establish the extent of pipe exposure needed (i.e., the size of the bell hole), to explicitly account for these uncertainties and their cumulative effect on the precise location of predicted liquid dropout.

(3) *Identification of locations for excavation and direct examination.* An operator must comply with the requirements ~~and recommendations~~ in NACE SP0206-2006 in conducting the detailed examination step of the ICDA process. In addition, on the first use of ICDA for a covered segment, an operator must identify a minimum of two locations for excavation within each ICDA Region and must perform a detailed examination for internal corrosion at each location, using ultrasonic thickness measurements, radiography, or other generally accepted measurement technique. One location must be the low point (*e.g.,* sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA Region. The second location must be further downstream, within a covered segment, near the end of the ICDA Region. If corrosion exists at either location, the operator must—

  (i) Evaluate the severity of the defect (remaining strength) and remediate the defect in accordance with §192.933; if the condition is in a covered segment, or in accordance with §§ 192.485 and 192.713 if the condition is not in a covered segment;

  (ii) Expand the detailed examination program, whenever internal corrosion is discovered, to determine all locations that have internal corrosion within the ICDA region, and accurately characterize the nature, extent, and root cause of the internal corrosion. In cases where the internal corrosion was identified within the ICDA region but outside the covered segment, the expanded detailed examination program must also include at least two detailed examinations within each covered segment associated with the ICDA region, at the location within the covered segment(s) most likely to have internal corrosion. One location must be the low point (e.g., sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA Region. The second location must be further downstream, within the covered segment. In instances of first use of ICDA for a covered segment, where these locations have already been examined per paragraph (3) of this section, two additional detailed examinations must be conducted within the covered segment; and

(iii) Expand the detailed examination program to evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator's pipeline system with similar characteristics to the ICDA region containing the covered segment in which the corrosion was found, and as appropriate, remediate the conditions the operator finds in accordance with §192.933 or § 192.713, as appropriate.

(4) *Post-assessment evaluation and monitoring.* An operator must comply with the requirements ~~and recommendations~~ in NACE SP0206-2006 in performing the post assessment step of the ICDA process. provide for evaluating the effectiveness of the ICDA process and continued monitoring of covered segments where internal corrosion has been identified. In addition, the post-assessment requirements ~~and recommendations~~ in NACE SP0206-2006, the evaluation and monitoring process includes—

(i) Evaluating the effectiveness of ICDA as an assessment method for addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals than those specified in §192.939. An operator must carry out this evaluation within a year of conducting an ICDA;

(ii) Validation of the flow modeling calculations by comparison of actual locations of discovered internal corrosion with locations predicted by the model (if the flow model cannot be validated, the ICDA is not feasible for the segment); and

(iii) Continually monitoring each ICDA region which contains a covered segment where internal corrosion has been identified using techniques such as coupons or UT sensors or electronic probes, and by periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products. An operator must base the frequency of the monitoring and liquid analysis on results from all integrity assessments that have been conducted in accordance with the requirements of this subpart, and risk factors specific to the ICDA region. At a minimum, the monitoring frequency must be two times each calendar year, but at intervals not exceeding 7½ months. If an operator finds any evidence of corrosion products in the ICDA region, the operator must take prompt action in accordance with one of the two following required actions and remediate the conditions the operator finds in accordance with § 192.933.

(A) Conduct excavations of, and detailed examinations at, locations downstream from where the electrolyte might have entered the pipe to investigate and accurately characterize the nature, extent, and root cause of the corrosion, including the monitoring and mitigation requirements of § 192.478; or

(B) Assess the covered segment using ~~**ILI tools capable of detecting internal corrosion**~~ **an integrity assessment method allowed by this subpart.**

(5) Other requirements. The ICDA plan must also include the following:

The Associations encourage PHMSA not to explicitly require assessment via ILI. Instead operators should be permitted to use assessment methods allowed by this part for internal corrosion.

(i) Criteria an operator will apply in making key decisions (e.g., ICDA feasibility, definition of ICDA Regions and Sub-regions, conditions requiring excavation) in implementing each stage of the ICDA process;

(ii) Provisions that analysis be carried out on the entire pipeline in which covered segments are present, except that application of the remediation criteria of §192.933 may be limited to covered segments.

K. Proposed Changes to §192.929: Incorporation of the GPAC Votes, Discussion & Industry Comments

The GPAC generally votes on concepts, rather than specific language, when reviewing the modified requirements for Stress Corrosion Cracking Direct Assessment (SCCDA) in the Proposed Rule. The Associations provide the following modifications to proposed §192.929 for PHMSA's consideration. The Associations believe the modifications shown in **red** reflect the approved language as discussed at the December 2017 GPAC meeting. As discussed in these comments, the Associations have also identified additional concerns that were not voted on by the GPAC, shown in **blue**, but were shared during public comment or identified through written comments by the Associations on the Proposed Rule.

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

(a) *Definition.* Stress Corrosion Cracking Direct Assessment (SCCDA) is a process to assess a covered pipe segment for the presence of SCC primarily by systematically gathering and analyzing excavation data for pipe having similar operational characteristics and residing in a similar physical environment.

(b) *General requirements.* An operator using direct assessment as an integrity assessment method to address stress corrosion cracking in a covered pipeline segment must develop and follow an SCCDA plan that meets all requirements ~~and recommendations~~ contained in NACE SP0204-2008 and that implements all four steps of the SCCDA process including pre-assessment, indirect inspection, detailed examination and post-assessment. As specified in NACE SP0204-2008, Section 1.1.7, SCCDA is complementary with other inspection methods such as in-line inspection (ILI) or hydrostatic testing and is not necessarily an alternative or replacement for these methods in all instances. In addition, the plan must provide for—

(1) *Data gathering and integration.* An operator's plan must provide for a systematic process to collect and evaluate data for all covered segments to identify whether the conditions for SCC are present and to prioritize the covered segments for assessment in accordance with NACE SP0204-2008, Sections 3 and 4, and Table 1. This process must also include gathering and evaluating data related to SCC at all sites an operator excavates during the conduct of its pipeline operations (both within and outside covered segments) where NACE SP0204-2008, Section 5.3 indicate the potential for SCC. This data gathering process must be conducted in accordance with NACE SP0204-2008, Section 5.3, and must include, at minimum data listed in NACE SP0204-2008, Table 2. Further the following factors must be analyzed as part of this evaluation:

(i) The effects of a carbonate-bicarbonate environment, including the implications of any factors that promote the production of a carbonate-bicarbonate environment such as soil temperature, moisture, the presence or generation of carbon dioxide, and/or Cathodic Protection (CP).

> As discussed above, the Associations recommend that PHMSA refrain from making recommendations in consensus standards mandatory for operators. Per Chairman Danner (12/15/2017 Transcript pg. 157): "That the way that we've got it referenced and the way that it's actually written in the standard, it would be for them to consider. Its not mandatory because if you go and look at the standards, there's a bunch of should and mays…"
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> Per Mr. Mayberry: "If I may, what we're saying is we're going to address that and pretty much leave the standard as is where the shalls [are] shall, they will be expected. If it's a should it, they would need to consider it and if it's relevant they would do it, if not they wouldn't.

(ii) The effects of cyclic loading conditions on the susceptibility and propagation of SCC in both high-pH and near-neutral-pH environments.
(iii) The effects of variations in applied CP such as overprotection, CP loss for extended periods, and high negative potentials.
(iv) The effects of coatings that shield CP when disbonded from the pipe.
(v) Other factors which affect the mechanistic properties associated with SCC including but not limited to historical and present-day operating pressures, high tensile residual stresses, flowing product temperatures, and the presence of sulfides.

(2) *Assessment method.* In addition to the requirements ~~and recommendations~~ of NACE SP0204-2008, section 4. The plan's procedures for indirect inspection must include provisions for conducting at least two above ground surveys using complementary measurement tools most appropriate for the pipeline segment based on the data gathering and integration step.

(3) *Direct examination*. In addition to the requirements ~~and recommendations~~ of NACE SP0204-2008, The plan's procedures for direct examination must provide for conducting a minimum of three direct examinations within the SCC segment at locations determined to be the most likely for SCC to occur.

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

(i) Removing the pipe with SCC, remediating the pipe with a Type B sleeve, hydrostatic testing in accordance with (b)(4)(ii), below, or by grinding out the SCC defect and repairing the pipe. If grinding is used for repair, the repair procedure must include: nondestructive testing for any remaining cracks or other defects; measuring remaining wall thickness; and the remaining strength of the pipe at the repair location must be determined using ASME/ANSI B31G or RSTRENG and must be sufficient to meet the design requirements of subpart C of this part. 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.~~ <u>If diameter or wall thickness is not known or not adequately documented by traceable, verifiable, and complete records, then the operator must:</u>

(A) <u>Use data from comparable pipe with known properties and traceable, verifiable, and complete records; or</u>

(B) <u>Verify these properties using the material documentation process specified in §192.607.</u>

> For an ECA on a pipe segment without TVC records of certain material properties, the operator should be able to use known properties that are documented by TVC records on comparable pipe. Furthermore, the code provides for certain conservative assumptions for material properties that operators should be allowed to use for remaining strength calculations.

<u>If longitudinal joint factor is not known or not adequately documented by traceable, verifiable, and complete records, then the operator must:</u>

(A) <u>Use data from comparable pipe with known properties and traceable, verifiable, and complete records;</u>

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

(C) Assume an "other" joint factor in accordance with §192.113.

If SMYS or actual material yield is not known or not adequately documented by traceable, verifiable, and complete records, then the operator must:

(A) Use data from comparable pipe with known properties and traceable, verifiable, and complete records;

(B) Verify these properties based upon the material documentation process specified in § 192.607; or

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

(ii) Significant SCC must be tested ~~mitigated~~ using a spike pressure test or other assessment method in accordance with §192.506. ~~hydrostatic testing program to a minimum test pressure equal to 105 percent of the specified minimum yield strength of the pipe for 30 minutes immediately followed by a pressure test in accordance with § 192.506, but not lower than 1.25 times MAOP. The test pressure for the entire sequence must be continuously maintained for at least 8 hours, in accordance with § 192.506 and must be above the minimum test factors in §§ 192.619(a)(2)(ii) or 192.620(a)(2)(ii), but not lower than 1.25 times maximum allowable operating pressure.~~ Any test failures due to SCC must be repaired by replacement of the pipe segment, and the segment re-tested ~~until the pipe passes the complete test without leakage.~~ Pipe segments that have SCC present, but that pass the assessment criteria ~~pressure test~~, may be repaired by grinding any discovered indications accordance with paragraph (b)(4)(i).

A spike pressure test doesn't mitigate SCC. It's an assessment method. Pipe replacement or grinding is the mitigation. Operators should also be permitted to use other SCC assessment methods aside from spike testing, such as ILI, as allowed by § 192.506.

Per PHMSA response to public comment (12/15/2017 Transcript pg. 143): Replace redundant language on spike test requirements with reference to § 192.506

A spike test is a strength test, not a leak test. A pipe can pass assessment criteria with minimal leakage. Identifiable leaks should be repaired and retested. If leakage is evident on a pressure chart and cannot be found in the line pipe, this is appropriate place for instrumented leak survey.

(5) *Post assessment*. In addition to the requirements ~~and recommendations~~ of NACE SP0204-2008, sections 6.3, periodic reassessment, and 6.4, effectiveness of SCCDA, The operator's procedures for post assessment must include development of a reassessment plan based on the susceptibility of the operator's pipe to SCC as well as on the mechanistic behavior of identified cracking. Reassessment intervals must comply with section 192.939 of this part. Factors that must be considered include, but are not limited to:

(ii) Evaluation of discovered crack clusters during the direct examination step. in accordance with NACE RP0204-2008, sections 5.3.5.7, 5.4, and 5.5;

(iii) Conditions conducive to creation of the carbonate-bicarbonate environment;

(iv) Conditions in the application (or loss) of CP that can create or exacerbate SCC;

(v) (Operating temperature and pressure conditions including operating stress levels on the pipe;

(vi) Cyclic loading conditions;

(vii) Mechanistic conditions that influence crack initiation and growth rates;

(viii) The effects of interacting crack clusters;

(ix) The presence of sulfides; and.

(x) Disbonded coatings that shield CP from the pipe.

L. Proposed Changes to Appendix F: Incorporation of GPAC Votes & Industry Comments

The GPAC generally votes on concepts, rather than specific language, when reviewing the modified requirements for Criteria for Conducting Integrity Assessments Using Guided Wave Ultrasonic Testing (GWUT) in the Proposed Rule. While the GPAC voted to approve Appendix F as proposed, the Associations provide the following modifications, shown in **blue**, to proposed Appendix F for PHMSA's consideration. These concerns, while not voted on by the GPAC, were shared during public comment or identified through written comments by the Associations on the Proposed Rule.

Appendix F to Part 192–Criteria for Conducting Integrity Assessments Using Guided Wave Ultrasonic Testing (GWUT)

This appendix defines criteria which must be properly implemented for use of Guided Wave Ultrasonic Testing (GWUT) as an integrity assessment method. Any application of GWUT that does not conform to these criteria is considered "other technology **or another process**" as described by §§ 192.710(c)(7), 192.921(a)(7), and 192.937(c)(7), for which OPS must be notified **90** ~~180~~ days prior to use in accordance with §§ 192.921(a)(7) or 192.937(c)(7). GWUT in the "Go-No Go" mode means that all indications (wall loss anomalies) above the testing threshold (a maximum of 5% of cross sectional area (CSA) sensitivity) be directly examined, in-line tool inspected, pressure tested or replaced prior to completing the integrity assessment on the cased carrier pipe.

Per voting slide for Strengthening IM Assessment methods, bullet 2 – "Revise the 'no objection' process as recommended by members at GPAC per the recommended procedure under §192.607…"

I. *Equipment and Software: Generation.* The equipment and the computer software used are critical to the success of the inspection. Guided Ultrasonic LTD (GUL) Wavemaker G3 or G4 with software version 3 or higher, or equipment and software with equivalent capabilities and sensitivities, must be used.

II. *Inspection Range*. The inspection range and sensitivity are set by the signal to noise (S/N) ratio but must still keep the maximum threshold sensitivity at 5% cross sectional area (CSA). A signal that has an amplitude that is at least twice the noise level can be reliably interpreted. The greater the S/N ratio the easier it is to identify and interpret signals from small changes. The signal to noise ratio is dependent on several variables such as surface roughness, coating, coating condition, associated pipe fittings (T's, elbows, flanges), soil compaction, and environment. Each of these affects the propagation of sound waves and influences the range of the test. It may be necessary to inspect from both ends of the pipeline segment to achieve a full inspection. In general the inspection range can approach 60 to 100 feet for a 5% CSA, depending on field conditions.

III. *Complete Pipe Inspection.* To ensure that the entire pipeline segment is assessed there should be at least a 2 to 1 signal to noise ratio across the entire pipeline segment that is inspected. This may require multiple GWUT shots. Double ended inspections are expected. These two inspections are to be overlaid to show the minimum 2 to 1 S/N ratio is met in the middle. If possible, show the same near or midpoint feature from both sides and show an approximate 5% distance overlap.

IV. *Sensitivity.* The detection sensitivity threshold determines the ability to identify a cross sectional change. The maximum threshold sensitivity cannot be greater than 5% of the cross sectional area (CSA).

The locations and estimated CSA of all metal loss features in excess of the detection threshold must be determined and documented.

All defect indications in the "Go-No Go" mode above the 5% testing threshold must be directly examined, in-line inspected, pressure tested, or replaced prior to completing the integrity assessment.

V. *Wave Frequency.* Because a single wave frequency may not detect certain defects, a minimum of three frequencies must be run for each inspection to determine the best frequency for characterizing indications. The frequencies used for the inspections must be documented and must be in the range specified by the manufacturer of the equipment.

VI. *Signal or Wave Type: Torsional and Longitudinal*. Both torsional and longitudinal waves must be used **in the course of the assessment** and use must be documented. **In most cases torsional wave will be used for the majority of the assessment and be complemented by longitudinal wave in the areas of the collar.**

VII. *Distance Amplitude Correction (DAC) Curve and Weld Calibration.* The Distance Amplitude Correction curve accounts for coating, pipe diameter, pipe wall and environmental conditions at the assessment location. The DAC curve must be set for each inspection as part of establishing the effective range of a GWUT inspection.

DAC curves provide a means for evaluating the cross sectional area change of reflections at various distances in the test range by assessing signal to noise ratio. A DAC curve is a means of taking apparent attenuation into account along the time base of a test signal. It is a line of equal sensitivity along the trace which allows the amplitudes of signals at different axial distances from the collar to be compared.

In proposed Appendix F, use of both torsional and longitudinal signal is required, but the extent that each type must be used is not clear. GWUT would become impractical in most cases if both signals are required on the entire segment because the longitudinal signal cannot be used on buried segments. The longitudinal signal is used only to spot check the exposed areas where the collar is installed. Per Member Drake (12/15/2017 Transcript pg. 146): "requirements of both torsional and longitudinal wave modes in all situations introduce unnecessary complexity into the guided wave ultrasonic data interpretation process. Specifically, torsional wave mode is the primary wave made when utilizing GWUT. Longitudinal wave mode may be used as an optional secondary mode**."**

VIII. *Dead Zone.* The Dead Zone is the area adjacent to the collar in which the transmitted signal blinds the received signal, making it impossible to obtain reliable results. Because the entire line must be inspected, inspection procedures must account for the dead zone by requiring the movement of the collar for additional inspections. An alternate method of obtaining valid readings in the dead zone is to use B-scan ultrasonic equipment and visual examination of the external surface. The length of the dead zone and the near field for each inspection must be documented.

IX. *Near Field Effects.* The Near Field is the region beyond the Dead Zone where the receiving amplifiers are increasing in power, before the wave is properly established. Because the entire line must be inspected, inspection procedures must account for the near field by requiring the movement of the collar for additional inspections. An alternate method of obtaining valid readings in the near field is to use B-scan ultrasonic equipment and visual examination of the external surface. The length of the dead zone and the near field for each inspection must be documented.

X. *Coating Type.* Coatings can have the effect of attenuating the signal. Their thickness and condition are the primary factors that affect the rate of signal attenuation. Due to their variability, coatings make it difficult to predict the effective inspection distance.

Several coating types may affect the GWUT results to the point that they may reduce the expected inspection distance. For example, concrete coated pipe may be problematic when well bonded due to the attenuation effects. If an inspection is done and the required sensitivity is not achieved for the entire length of the cased pipe, then another type of assessment method must be utilized.

XI. *End Seal.* Operators must remove the end seal from the casing at each GWUT test location to facilitate visual inspection. Operators must remove debris and water from the casing at the end seals. Any corrosion material observed must be removed, collected and reviewed by the operator's corrosion technician. The end seal does not interfere with the accuracy of the GWUT inspection but may have a dampening effect on the range.

XII. *Weld Calibration to set DAC Curve.* Accessible welds, along or outside the pipe segment to be inspected, must be used to set the DAC curve. A weld or welds in the access hole (secondary area) may be used if welds along the pipe segment are not accessible. In order to use these welds in the secondary area, sufficient distance must be allowed to account for the dead zone and near field. There must not be a weld between the transducer collar and the calibration weld. A conservative estimate of the predicted amplitude for the weld is 25% CSA (cross sectional area) and can be used if welds are not accessible. Calibrations (setting of the DAC curve) should be on pipe with similar properties such as wall thickness and coating. If the actual weld cap height is different from the assumed weld cap height, the estimated CSA may be inaccurate and adjustments to the DAC curve may be required. Alternative means of calibration can be used if justified by sound engineering analysis and evaluation.

XIII. *Validation of Operator Training*. ~~There is no industry standard for qualifying GWUT service providers.~~ Pipeline operators must require all guided wave service providers to have equipment-specific training and experience for all GWUT Equipment Operators which includes training for:

The Associations believe the statement that "there is no industry standard for qualifying GWUT service providers" is inappropriate for regulatory text.

A. equipment operation,
B. field data collection, and
C. data interpretation on cased and buried pipe.

Only individuals who have been qualified by the manufacturer or an independently assessed evaluation procedure similar to ISO 9712 (Sections: 5 Responsibilities; 6 Levels of Qualification; 7 Eligibility; and 10 Certification), as specified above, may operate the equipment.

A Senior Level GWUT Equipment Operator with pipeline specific experience must provide onsite oversight of the inspection and approve the final reports. A Senior Level GWUT Equipment Operator must have additional training and experience, including but not limited to training specific to cased and buried pipe, with a quality control program which conforms to Section 12 of ASME B31.8S.

Training and Experience Minimums for Senior Level GWUT Equipment Operators:

- Equipment Manufacturer's minimum qualification for equipment operation and data collection with specific endorsements for casings and buried pipe
- Training, qualification and experience in testing procedures and frequency determination
- Training, qualification and experience in conversion of guided wave data into pipe features and estimated metal loss (estimated cross-sectional area loss and circumferential extent)

- Equipment Manufacturer's minimum qualification with specific endorsements for data interpretation of anomaly features for pipe within casings and buried pipe.

XIV. *Equipment: traceable from vendor to inspection company.* The operator must maintain documentation of the version of the GWUT software used and the serial number of the other equipment such as collars, cables, etc., in the report.

XV. *Calibration Onsite.* The GWUT equipment must be calibrated for performance in accordance with the manufacturer's requirements and specifications, including the frequency of calibrations. A diagnostic check and system check must be performed on-site each time the equipment is relocated. If on-site diagnostics show a discrepancy with the manufacturer's requirements and specifications, testing must cease until the equipment can be restored to manufacturer's specifications.

XVI. XVI. *Use on Shorted Casings (direct or electrolytic).* ~~GWUT may not be used to assess shorted casings. GWUT operators must have operations and maintenance procedures (*see § 192 .605*) to address the effect of shorted casings on the GWUT signal.~~ The equipment operator <u>must assure the accuracy of the data is not compromised by the shorted casing, and only use data which meets the specification.</u> ~~clear any evidence of interference, other than some slight dampening of the GWUT signal from the shorted casing, according to their operating and maintenance procedures.~~ All shorted casings found while conducting GWUT inspections must be addressed by the operator's standard operating procedures <u>under 192.605</u>.

> The Associations maintain the technology supporting GWUT has improved dramatically and cased pipes that have a metallic short or electrolytic short can still potentially be assessed. (See Mr. Osman's comments from page 116 of the Meeting Minutes from Dec 15, 2017. "… *also PHMSA has prohibited the use of guided wave on shorted casings. We think the GPAC should discuss that because there's value in using guided wave on shorted casings.").*

XVII. *Direct examination of all indications above the detection sensitivity threshold.*
The use of GWUT in the "Go-No Go" mode requires that all indications (wall loss anomalies) above the testing threshold (5% of CSA sensitivity) be directly examined (or replaced) prior to completing the integrity assessment on the cased carrier pipe. If this cannot be accomplished then alternative methods of assessment (such as hydrostatic pressure tests or ILI) must be utilized.

XVIII. *Timing of direct examination of all indications above the detection sensitivity threshold.* Operators must either replace or conduct direct examinations of all indications identified above the detection sensitivity threshold according to the table below. Operators must conduct leak surveys and reduce operating pressure as specified until the pipe is replaced or direct examinations are completed.

Required Response to GWUT Indications			
GWUT Criterion	Operating Pressure less than or equal to 30% SMYS	Operating pressure over 30 and less than or equal to 50% SMYS	Operating pressure over 50% SMYS
Over the detection sensitivity threshold (maximum of 5% CSA)	Replace or direct examination within 12 months, and instrumented leak	Replace or direct examination within 6 months, and instrumented leak survey once every 30	Replace or direct examination within 6 months, and instrumented leak survey once every 30

	survey once every 30 calendar days.	calendar days, and maintain MAOP below the operating pressure at time of discovery.	calendar days, and reduce MAOP to 80% of operating pressure at time of discovery.

V. 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.

The following topics in the rulemaking have been discussed in at least one GPAC meeting, but still 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	
§192.13(e)	Introduces a general record provision
§192.67	Adds prospective material record requirement
§192.127	Adds prospective pipe design record requirement
§192.205	Adds prospective pipeline component record requirement
§192.619(f)	Introduces a MAOP determination record requirement
Appendix A	Provides a record retention schedule for Transmission lines
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
Strengthened Assessment Requirements	
§192.493	Incorporates by reference of industry standards for ILI tools and performing ILI
§192.921(a)	Introduces of additional disclaimers concerning the use of specific assessment methods & the addition of new approve assessment methods.
§192.506	Requirements for spike hydrostatic pressure testing

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
Assessments Outside of HCAs	

§192.710	Requires transmission pipelines outside HCAs to perform assessments on threats to which the pipeline is susceptible
Response and Remediation Criteria	
§192.485	Adds requirements for pressure reduction/pipe replacement calculations when corrosion has been identified on gas transmission pipelines
§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	
Moderate Consequence Area & Occupied Site	
Transmission Line & Distribution Center	
"Able to accommodate inspection by means of an instrumented ILI device"	
Significant Seam Cracking	
Significant Stress Corrosion Cracking	
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,
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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

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

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