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 No. PHMSA-2016-0136

COMMENTS ON PHMSA'S GAS PIPELINE ADVISORY COMMITTEE (GPAC) MEETING HELD JUNE 6-7, 2017

FILED BY
AMERICAN GAS ASSOCIATION
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INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

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Contents

I. Introduction

The American Gas Association (AGA)[1], American Petroleum Institute (API)[2], and Interstate Natural Gas Association of America (INGAA)[3] (jointly "the Associations") submit these comments for consideration by the Pipeline and Hazardous Materials Safety Administration (PHMSA) concerning the second Gas Pipeline Advisory Committee (GPAC) meeting on the Safety of Gas Transmission & Gathering Lines Rulemaking (Proposed Rule)[4] that occurred on June 6-7, 2017.[5] 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 first GPAC meeting on this rulemaking[6] that were intended to summarize the views expressed during the meeting and elaborate on the concerns identified. Additionally, the Associations provided markups to the proposed regulatory text that was meant to mirror the votes and discussions held by the GPAC. The following comments on the June GPAC meeting are similar in content and structure.

For several topics, the second 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, and practicable. For other topics, the conversations made strides in identifying concerns, but certain topics 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.

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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] 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.

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

[5] Pipeline Safety: Meeting of the Gas Pipeline Safety Advisory Committee, 82 Fed. Reg. 23714 (May 23, 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.

[6] Pipeline Safety: Meeting of the Gas Pipeline Safety Advisory Committee, 81 Fed. Reg. 83795 (November 22, 2016), held January 11-12 2017.

II. Corrosion Control

A. Proposed Changes to §192.319: Incorporation of the GPAC Votes

The GPAC generally voted on concepts, rather than specific language, when reviewing the proposed changes to the corrosion control requirements after installing a pipe in a ditch. The Associations understand that specific language will not be offered at the next GPAC meeting and, therefore, provide the following modifications to proposed § 192.319(d) for PHMSA's consideration. The Associations believe the modifications shown in **red** reflect the approved language as discussed at the June 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.

§192.319 Installation of pipe in a ditch.

(d) Promptly after a ditch for a steel onshore transmission line is backfilled **(if there is 1,000 feet or more of contiguous backfill length along the pipeline)**, but not later than ~~**three months**~~ **six months** after placing the pipeline in service, the operator must perform an assessment to ensure integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG)**, or equivalent**[7]. The operator must repair any coating damage classified as ~~**moderate or**~~ severe ~~**(voltage drop greater than 35% for DCVG or 50 dBμv for ACVG)**~~ in accordance with section 4 of NACE SP0502 (incorporated by reference, see § 192.7) within six months of the assessment. **If permits are necessary, remedial action must be completed promptly after receipt of all necessary permits.** Each operator of transmission pipelines must make and retain for the life of the pipeline records documenting the ~~**coating**~~ **indirect** assessment findings and ~~**repairs**~~ **remedial actions**.

Per GPAC Vote (Slide 16, Bullet #2), PHMSA will "modify the applicability of this requirement to segments >1000' to be consistent with 192.461." Since this requirement applies to *segments* greater than 1000', the associations suggest PHMSA reference "contiguous" backfill.

Per GPAC Vote (Slide 16, Bullet #3), PHMSA will "lengthen the assessment & remediation timeframe to 6 months after the pipeline is placed in service (192.319) and provide allowance for delayed permitting."

Per GPAC Vote (Slide 16, Bullet #4), PHMSA will "provide flexibility for technology unless objected to by PHMSA."

Per GPAC Vote (Slide 16, Bullet #1), PHMSA will "raise the repair threshold from 'moderate' to 'severe' indications." NACE SP0502 describes in detail the process by which an operator must evaluate coating damage and how to identify "severe" coating damage. No NACE standard or publication provides numerical voltage drop thresholds for "severe" coating damage.

Also, PHMSA should use the term "remediate" instead of "repair," consistent with a similar requirement in existing 192.620.

Per GPAC Vote (Slide 16, Bullet #5), PHMSA will "modify records requirements as follows: '… make and retain for the life of the pipeline records documenting the ~~coating~~ **indirect** assessment findings and ~~repairs~~ **remedial actions**."

[7] The Associations believe it is necessary for the GPAC to discuss the newly proposed concept of "no objection letters" before it is widely incorporated throughout pipeline safety regulations. Therefore, the Associations have not included this concept in the redlined code language at this time.

B. Proposed Changes to §192.461: Incorporation of GPAC Votes

The GPAC generally voted on concepts, rather than specific language, when reviewing the proposed changes to the corrosion control requirements for external corrosion control: protective coating. The Associations understand that specific language will not be offered at the next GPAC meeting and, therefore, provide the following modifications to proposed § 192.461(f) for PHMSA's consideration. The Associations believe the modifications shown in **red** reflect the approved language as discussed at the June 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.

§ 192.461 External corrosion control: Protective coating.

(f) Promptly, but no later than **~~three months~~** **six months** after backfill of an onshore transmission pipeline ditch following repair or replacement (if the repair or replacement results in 1,000 feet or more of backfill length along the pipeline), conduct surveys to assess any coating damage to ensure integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG)**, or equivalent**[8]. Remediate any coating damage classified as **~~moderate or~~** severe **~~(voltage drop greater than 35% for DCVG or 50 dBµv for ACVG)~~** in accordance with section 4 of NACE SP0502 (incorporated by reference, see § 192.7) within six months of the assessment. **If permits are necessary, remedial action must be completed promptly following receipt of all necessary permits.**

Per GPAC Vote (Slide 16, Bullet #3), PHMSA will "lengthen the assessment & remediation timeframe to 6 months after the pipeline is placed in service (192.319) and provide allowance for delayed permitting." Additionally, the Associations remind PHMSA of the comments made by Member Drake regarding compliance considerations when there are physical access restrictions (see pp. 54 & 57 of June 6 meeting transcript).

Per GPAC Vote (Slide 16, Bullet #4), PHMSA will "provide flexibility for technology unless objected to by PHMSA."

Per GPAC Vote (Slide 16, Bullet #1), PHMSA will "raise the repair threshold from 'moderate' to 'severe' indications." NACE SP0502 describes in detail the process by which an operator must evaluate coating damage and how to identify "severe" coating damage. No NACE standard or publication provides numerical voltage drop thresholds for "severe" coating damage.

[8] The Associations believe it is necessary for the GPAC to discuss the newly proposed concept of "no objection letters" before it is widely incorporated throughout pipeline safety regulations. Therefore, the Associations have not included this concept in the red-lined code language at this time.

C. Proposed Changes to §192.465: Incorporation of GPAC Votes

The GPAC generally voted on concepts, rather than specific language, when reviewing the proposed changes to the corrosion control requirements for external corrosion control monitoring. The Associations understand that specific language will not be offered at the next GPAC meeting and, therefore, provide the following modifications to proposed § 192.465 for PHMSA's consideration. The Associations believe the modifications shown in **red** reflect the approved language as discussed at the June 2017 GPAC meeting.

§ 192.465 External corrosion control: Monitoring

(d) Each operator **of an onshore gas transmission line**[9] must promptly correct any deficiencies indicated by the inspection and testing provided in paragraphs (a), (b) and (c) of this section. **Within 6 months the operator must develop a** remedial action **procedure and apply for any necessary permits**. **The** ~~**must be**~~ **operator must complete remedial action within twelve months or as soon as practicable after obtaining necessary permits.**[10] ~~**completed promptly, but no later than the next monitoring interval in § 192.465 or within one year, whichever is less.**~~

Per GPAC Vote (Slide 22, Bullet #1), PHMSA will "clarify that the new requirements in paragraph 192.465(d) only apply to gas transmission pipelines."

Per GPAC Vote (Slide 22, Bullet #2), PHMSA will "address comments on timeframe to require remedial action plan and apply any necessary permits within 6 months and complete remedial action within 1 calendar year, not to exceed 15 months, or as practicable after obtaining necessary permits."

(f) For onshore **gas** transmission lines, where any annual test station reading (pipe-to-soil potential measurement) indicates cathodic protection levels below the required levels in Appendix D of this part, the operator must determine the extent of the area with inadequate cathodic protection. Close interval surveys must be conducted in both directions from the test station with a low cathodic protection (CP) reading at a minimum of approximately five foot intervals. Close interval surveys must be conducted, where practical based upon geographical, technical, or safety reasons. Close interval surveys required by this part must be completed with the protective current interrupted unless it is impractical to do so for technical or safety reasons. Remediation of areas with insufficient cathodic protection levels or areas where protective current is found to be leaving the pipeline must be performed in accordance with paragraph (d). The operator

[9] PHMSA clarified in the June 2017 meeting that changes to gathering lines will be addressed in a future meeting when the committee considers the proposed changes to 192.9. See the note on slide 7 in the final PHMSA presentation. As written, sections 192.465(d) pertains to transmission lines. However, since section 192.465(d) is not appropriately excluded in 192.9, the proposed sections could apply to gathering lines. The Associations request that PHMSA note this discrepancy and address revisions for 192.9 in a separate meeting dedicated to gathering lines.

[10] See June 6 transcript comments (page 123-124) of Ms. Erin Kurilla and Mr. Carl Weimer. Mr. Weimer: "To that last point about whether to go with 12 or 15 months, I guess since we're adding the allowance for delayed permitting, I think it's fine just to leave it with 12 with that allowance for the delayed permitting." See also comments of Mr. Danner – page 134.

must confirm restoration of adequate cathodic protection by close interval survey over the entire area. **Close interval surveys are not required in instances where low potentials are a result of electrical short to an adjacent foreign structure, rectifier malfunction, interruption of power source, or interruption of CP current due to other causes. If an operator identifies the potential cause of the low CP reading while conducting the close interval surveys, additional survey points may be unnecessary to perform remediation. In these cases, following the remedial measures, operators must perform a close interval survey over the area found to be deficient to confirm restoration of adequate cathodic protection.**

Per GPAC Vote (Slide 22, Bullet #3), PHMSA will "address situations where CIS may not be an effective response to require that operators investigate and mitigate any non-systemic or location-specific causes, and that close interval surveys would only be required to address systemic causes." The Associations offer the language below to attempt to capture this point.

D. Proposed Changes to Appendix D: Incorporation of GPAC Votes

During the June 2017 GPAC meeting, PHMSA agreed to remove all proposed modifications to Appendix D: *Criteria for Cathodic Protection and Determination Measurements*, which applies to both gas transmission and gas distribution pipelines[11].

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[11] See Slide 22. Bullet 4. "To address comments on proposed revisions to Appendix D, withdraw the proposed revisions to Appendix D from the final rule."

E. Proposed Changes to §192.473: Incorporation of GPAC Votes

The GPAC generally voted on concepts, rather than specific language, when reviewing the proposed changes to the corrosion control requirements for external corrosion control: interference currents. The Associations understand that specific language will not be offered at the next GPAC meeting and, therefore, provide the following modifications to proposed § 192.473 for PHMSA's consideration. The Associations believe the modifications shown in **red** reflect the approved language as discussed at the June 2017 GPAC meeting.

§ 192.473 External corrosion control: Interference currents.

(c) For onshore gas transmission pipelines **subject to stray currents**, the program required by paragraph (a) must include:

(1) Interference surveys for pipeline systems to detect the presence and level of any electrical stray current. Interference surveys must be taken on periodic basis including, when there are current flow increases over pipeline segment grounding design, from any co-located pipelines, structures, or high voltage alternating current (HVAC) power lines, including from additional generation, a voltage up rating, additional lines, new or enlarged power substations, new pipelines or other structures;

> Per GPAC Vote (Slide 27, Bullet #1), PHMSA will "clarify that surveys are required for lines subject to stray current."

(2) Analysis of the results of the survey to determine the cause of the interference and whether the level could **cause significant corrosion (defined as 100 amps per meter squared for AC-induced corrosion), or if it impedes the safe operation of a pipeline, or that may cause a condition that would adversely impact the environment or the public.** ~~impact the effectiveness of cathodic protection;~~ and

> Per GPAC Vote (Slide 27, Bullet #3), PHMSA will "clarify that remedial action is required when the interference is at a level that could cause significant corrosion (defined as 100 amps per meter squared), or if it impedes the safe operating pressure of a pipeline, or that may cause a condition that would adversely affect the environment or public."

(3) **Within 6 months after completion of the survey, the operator must develop a procedure and apply for necessary permits. The operator must complete all remediation within twelve months or as soon as practicable after obtaining necessary permits. Remedial action is required when the interference is at a level that could cause significant corrosion (defined as 100 amps per meter squared for AC-induced corrosion), or if it impedes the safe operation of a pipeline, or that may cause a condition that would adversely impact the environment or the public.** ~~Implementation of remedial actions to protect the pipeline segment from detrimental interference currents promptly but no later than six months after completion of the survey.~~

> Per GPAC Vote (Slide 27, Bullet #2), PHMSA will "update the timeframe for remediation to require a remediation procedure and application for necessary permits within 6 months and complete remediation within 12 months, with allowance for delayed permitting."

E. Proposed Changes to §192.478: Incorporation of GPAC Votes

The GPAC generally voted on concepts, rather than specific language, when reviewing the proposed changes to the corrosion control requirements for internal corrosion control: onshore transmission monitoring and mitigation. The Associations understand that specific language will not be offered at the next GPAC meeting and, therefore, provide the following modifications to proposed § 192.478 for PHMSA's consideration. The Associations believe the modifications shown in **red** reflect the approved language as discussed at the June 2017 GPAC meeting.

§ 192.478 Internal corrosion control: Onshore transmission monitoring and mitigation.

(a) For or onshore transmission pipelines **that transport corrosive gas**[12], each operator must develop and implement a monitoring and mitigation program to identify potentially corrosive constituents in the gas being transported and mitigate the corrosive effects**, including the requirements of §192.477**. Potentially corrosive constituents include but are not limited to: carbon dioxide, hydrogen sulfide, sulfur, microbes, and free water, either by itself or in combination. Each operator must evaluate the partial pressure of each corrosive constituent **identified**[13]**,** by itself or in combination**,** to evaluate the effect of the corrosive constituents on the internal corrosion of the pipe and implement mitigation measures.

(b) The monitoring and mitigation program in paragraph (a) of this section must include:

(1) At points where gas with potentially corrosive contaminants enters the pipeline, the use of gas-quality monitoring ~~equipment~~ **methods** to determine the gas stream constituents;

(2) ~~Product sampling, inhibitor injections, in-line cleaning pigging, separators or other technology to mitigate the potentially corrosive gas stream constituents.~~ **Technology to mitigate the potentially corrosive gas stream constituents. Such technologies may include product sampling, inhibitor injections, in-line cleaning pigging, separators or other technology to mitigate potentially corrosive gas stream constituents.**

Per GPAC Vote (Slide 32, Bullet #4), PHMSA will "limit the applicability of paragraph (a) to the transportation of corrosive gas. PHMSA will provide additional guidance based on the GPAC discussion."

Per GPAC Vote (Slide 32, Bullet #1), PHMSA will "modify (b)(1) as follows: 'At points where gas with potentially corrosive contaminants enters the pipeline, the use of gas-quality monitoring methods to determine the gas stream constituents."

Per GPAC Vote (Slide 32, Bullet #5), PHMSA will "revise (b)(2) to read 'technology to mitigate the potentially corrosive gas stream constituents. Such technologies may include product sampling and inhibitor injections."

In 192.478(b)(2), PHMSA should consider replacing the term "potentially corrosive gas stream constituents" with "corrosive effects." It is the "corrosive effects" that ultimately need to be mitigated, and this is consistent with proposed 192.478(a).

The Associations also remind PHMSA that certain constituents, such as microbes, would not have partial pressure.

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[12] PHMSA clarified in the June 2017 meeting that changes to gathering lines will be addressed in a future meeting when the committee considers the proposed changes to 192.9. See the note on slide 7 in the final PHMSA presentation. As written, section 192.478 pertains to transmission lines. However, since section 192.477 is not excluded in 192.9, 192.477 could apply to gathering lines. The Associations request that PHMSA note this discrepancy and address revisions for 192.9 in a separate meeting dedicated to gathering lines.

[13] Member Gosman & Chairman Danner: "PHMSA should add the word 'identified'." (6/6/2017 Transcript. Page 214).

(3) Evaluation ~~twice each~~ once per calendar year, at intervals not to exceed ~~7 ½~~ 15 months, of gas stream and liquid quality samples and implementation of adjustments and mitigative measures to ensure that potentially corrosive gas stream constituents are effectively monitored and mitigated.

> Per GPAC Vote (Slide 32, Bullet #2), PHMSA will "change frequency of monitoring and program review from twice per year to once per calendar year, not to exceed 15 months."

(c) ~~If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked at least twice each calendar year, at intervals not exceeding 7 ½.~~

> Per GPAC Vote (Slide 32, Bullet #3), PHMSA will "delete proposed paragraph (c) and refer to 192.477 in 192.478(a)."

(d) Each operator must review its monitoring and mitigation program at least ~~twice~~ once each calendar year, at intervals not to exceed ~~7 ½~~ 15 months, based on the results of its gas stream sampling and internal corrosion monitoring in (a) and (b) and implement adjustments in its monitoring for and mitigation of the potential for internal corrosion due to the presence of potentially corrosive gas stream constituents.

III. Corrosion Control - Preventative & Mitigative Measures

During the June 2017 GPAC meeting, PHMSA agreed to delete proposed sections §192.935(f) and §192.935(g) and the related proposed modifications to Appendix E: *Guidance on Determining High Consequence Areas and Carrying Out Requirements in the Integrity Management Rule.* PHMSA acknowledged that the proposed changes in Subpart I: *Requirements for Corrosion Control* apply to all transmission pipelines, both within High Consequence Areas (HCA) and outside HCAs, and address the same concerns as the proposed changes to §192.935[14].

[14] See Slide 37. PHMSA will "withdraw all proposed change to the regulations in 192.935(f) and (g), and Appendix E.

IV. Integrity Management Clarifications

A. Proposed Changes to §192.917(a)-(c): Incorporation of the GPAC Votes & Industry Comments

The GPAC generally voted on concepts, rather than specific language, when reviewing the requirements for integrity management clarifications in the Proposed Rule. The Associations understand that specific language will not be offered at the next GPAC meeting and, therefore, provide the following modifications to proposed §192.917(b), (c), and (e)(2) for PHMSA's consideration. The Associations believe the modifications shown in **red** reflect the approved language as discussed at the June 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.

§192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(a) *Threat identification.* An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 2, which are grouped under the following four categories:
  (1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;
  (2) Static or resident threats, such as manufacturing, welding/fabrication or equipment defects;
  (3) Time independent threats such as third party damage/mechanical damage, incorrect operational procedure, weather related and outside force damage; including consideration of seismicity, geology, and soil stability of the area; and
  (4) Human error such as operational mishaps and design and construction mistakes.

(b) *Data gathering and integration.* To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather, ~~verify, validate,~~ and integrate **pertinent** ~~existing~~ data and information on the entire pipeline that could be relevant to the covered segment.[15] In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. **Operators must begin to integrate pertinent data elements specified in this section starting [*insert date 1 year after effective date of the final rule*], with pertinent attributes integrated by [*insert date 3 years after publication of rule.*]** At a

Mr. Nanney stated "on 917(b) we had heard the committee want us to, in the actual wording, to take out, 'verify' and 'validate', and put in, 'gather' and 'integrate.'" (6/6/2017 Transcript. Page 329. Line 5)

Per the GPAC Vote (Slide 57, Bullet #1). PHMSA will add language to require data that is "pertinent" (and that a prudent operator would collect).

Per the GPAC Vote (Slide 57, Bullet #2). PHMSA will include an "implementation timeframe beginning in year 1 with full incorporation by 3 years."

[15] The approved voting slides from the June GPAC meeting included a reference to data that "a prudent operator would collect." The Associations agree that operators should be expected to collect pertinent data in a prudent manner. However, the Associations are concerned that this "prudent operator" standard is undefined, and it would be very complicated to enforce; the Associations do not believe that this term is appropriate for regulatory text. Instead, PHMSA should reference the GPAC's discussion around pertinent data that "a prudent operator would collect" in its preamble to the Final Rule.

minimum, an operator must gather and evaluate the set of data specified in paragraph (b)(1) of this section and Appendix A to ASME/ANSI B31.8S. The evaluation must analyze both the covered segment and similar non-covered segments, and must:

(1) Integrate <u>pertinent</u> information about pipeline attributes and other relevant information, including, but not limited to:
   - (i) Pipe diameter, wall thickness, grade, seam type and joint factor;
   - (ii) Manufacturer and manufacturing date, including manufacturing data and records;
   - (iii) ~~Material properties including, but not limited to, diameter, wall thickness, grade, seam type, hardness, toughness, hard spots, and chemical composition~~;
   - (iv) Equipment properties;
   - (v) Year of installation;
   - (vi) Bending method;
   - (vii) Joining method, including process and inspection results;
   - (viii) Depth of cover surveys including stream and river crossings, navigable waterways, and beach approaches;
   - (ix) Crossings, casings (including if shorted), and locations of foreign line crossings and nearby high voltage power lines;
   - (x) Hydrostatic or other pressure test history, including test pressures and test leaks or failures, failure causes, and repairs;
   - (xi) Pipe coating methods (both manufactured and field applied) including method or process used to apply girth weld coating, inspection reports, and coating repairs;
   - (xii) Soil, backfill;
   - (xiii) Construction inspection reports, including but not limited to:
     - ~~(A) Girth weld non-destructive examinations;~~
     - **(A)** Post backfill coating surveys;
     - (B) Coating inspection ("jeeping") reports;
   - (ii) Cathodic protection installed, including but not limited to type and location;
   - (iii) Coating type;
   - (iv) Gas quality;
   - (v) Flow rate;
   - (vi) Normal maximum and minimum operating pressures, including maximum allowable operating pressure (MAOP);
   - (vii) Class location;
   - (viii) Leak and failure history including any in-service ruptures or leaks from incident reports, abnormal operations, safety related conditions (both reported and unreported) and

> Per GPAC Vote (Slide 57, Bullet #1), PHMSA will "revise the listing of pipeline attributes in 192.917(b)(1) to be more consistent with existing regulations and B31.8S." PHMSA should remove proposed 192.917(b)(1)(iii). Diameter, wall thickness, grade, and seam type are already listed in (i). Hardness, toughness, hard spots, and chemical composition are not listed in ASME B31.8s – 2004.

> This Associations believe that calling out "stream crossings" separately is unnecessary and may create confusion. The depth of cover information for stream crossings will generally be similar as that for the rest of the pipeline right-of-way; operators will not necessarily identify/define "streams" separately. ASME B31.8S does not call out "streams" separately.

> "Girth weld non-destructive examinations" should be removed to stay consistent with ASME/ANSI B31.8S; girth weld inspection results would already be required by (vii) – joint method.

failure investigations required by § 192.617, and their identified causes and consequences;

(ix) Coating condition;

(x) CP system performance;

(xi) Pipe wall temperature;

(xii) Pipe operational and maintenance inspection reports, including but not limited to:

(A) Data gathered through integrity assessments required under this part, including but not limited to in-line inspections, pressure tests, direct assessment, guided wave ultrasonic testing, or other methods;

(B) Close interval survey (CIS) and electrical survey results;

(C) Cathodic protection (CP) rectifier readings;

(D) CP test point survey readings and locations;

(E) AC/DC and foreign structure interference surveys;

(F) Pipe coating surveys, including surveys to detect coating damage, disbonded coatings, or other conditions that compromise the effectiveness of corrosion protection, including but not limited to direct current voltage gradient or alternating current voltage gradient inspections;

(G) Results of examinations of exposed portions of buried pipelines (e.g., pipe and pipe coating condition, see § 192.459), including the results of any non-destructive examinations of the pipe, seam or girth weld, i.e. bell hole inspections;

(H) Stress corrosion cracking (SCC) excavations and findings;

(I) Selective seam weld corrosion (SSWC) excavations and findings;

(J) Gas stream sampling and internal corrosion monitoring results, including cleaning pig sampling results;

(xiii) Outer Diameter/Inner Diameter corrosion monitoring;

(xiv) Operating pressure history and pressure fluctuations, including analysis of effects of pressure cycling and instances of exceeding MAOP by any amount;

(xv) Performance of regulators, relief valves, pressure control devices, or any other device to control or limit operating pressure to less than MAOP;

(xvi) Encroachments ~~and right-of-way activity, including but not limited to, one-call data, pipe exposures resulting from encroachments, and excavation activities due to development or planned development along the pipeline;~~

> Mr. Nanney stated "We X'd out in right-of-way activity, we put, encroachments. The one word, that is in the B31.8S." (6/6/2017 Transcript. Page 332. Line 11).

(xvii) Repairs;

(xviii) Vandalism;

(xix) External forces;

(xx) Audits and reviews;

(xxi) Industry experience for incident, leak and failure history;

(xxii) Aerial photography;

(xxiii) Exposure to natural forces in the area of the pipeline, including seismicity, geology, and soil stability of the area; and

> Mr. Nanney stated "…there were some areas where we had added a XXXVI, and we had other pertinent information derived from operations and maintenance. That was some that was not in B31.8S. We did X that out."

(xxiv) ~~Other pertinent information derived from operations and maintenance activities and any additional tests, inspections, surveys, patrols, or monitoring required under this Part.~~

(2) Use ~~objective, traceable, verified, and~~ validated information and data as inputs, to the maximum extent practicable. If input is obtained from subject matter experts (SMEs), the operator must employ measures to adequately correct any bias in SME input. Bias control measures may include training of SMEs ~~and~~ or use of outside technical experts (independent expert reviews) to assess quality of processes and the judgment of SMEs. ~~Operator must document the names of all SMEs and information submitted by the SMEs for the life of the pipeline.~~

(3) Identify and analyze spatial relationships among anomalous information (e.g., corrosion coincident with foreign line crossings; evidence of pipeline damage where overhead imaging shows evidence of encroachment). ~~Storing or recording the information in a common location, including a geographic information system (GIS), alone, is not sufficient~~; and

(4) Analyze the data for interrelationships among pipeline integrity threats, including combinations of applicable risk factors that increase the likelihood of incidents or increase the potential consequences of incidents.

(c) *Risk assessment.* An operator must conduct a risk assessment that follows ASME / ANSI B31.8S, section 5, and analyzes the identified threats and potential consequences of an incident for each covered segment. ~~The risk assessment must include evaluation of the effects of interacting threats, including the potential for interactions of threats and anomalous conditions not previously evaluated.~~ An operator must ensure validity of the methods used to conduct the risk assessment in light of incident, leak, and failure history and other historical information. Validation must ensure the risk assessment methods produce a risk characterization that is consistent with the operator's and industry experience, including evaluations of the cause of past incidents, as determined by root cause analysis or other equivalent means, and include sensitivity analysis of the factors used to characterize both the ~~probability~~ likelihood of loss of pipeline integrity and consequences of the postulated loss of pipeline integrity. An operator must use the risk assessment to determine additional preventive and mitigative measures needed (§

Mr. Nanney (PHMSA) stated "In number (2) where we had used 'objective, traceable, verified, and validated information'; we just put 'validated information'." (6/6/2017 Transcript. Page 332. Line 18.)

It is impossible to correct all bias (for example, see comments of Mr. Zamarin on pp. 56-58 of June 7 transcript). Instead, the objective should be: "employ adequate controls measures to ensure consistency and accuracy of information."

Per the GPAC Vote (Slide 57, Bullet #3), PHMSA will "address the topic of SME bias… including the elimination of the last sentence the language (or revising the last sentence)."

Per GPAC Vote (Slide 57, Bullet #4), PHMSA will "not require a GIS system).

Per GPAC Vote (Slide 63, Bullet #1), PHMSA will "restore reference to B31.8S, Section 5 to clarify other methods besides probabilistic techniques may be used."

The Associations maintain that the requirement to address interacting threats is adequately addressed in proposed §192.917(c)(2). Therefore, the Associations recommend that PHMSA remove this sentence.

Per GPAC Vote (Slide 63, Bullet #2), "in §192.917(c), [PHMSA will] change the term 'probability' to 'likelihood'."

192.935) for each covered segment, and periodically evaluate the integrity of each covered pipeline segment (§ 192.937(b)).

Beginning [*insert date 3 years after the effective date of the final rule*] the risk assessment must:

(1) Analyze how a potential failure could affect high consequence areas~~, including the consequences of the entire worst-case incident scenario from initial failure to incident termination~~;

(2) Analyze the likelihood of failure due to each individual threat ~~or risk factor~~, and each unique combination of threats ~~or risk factors~~ that interact or simultaneously contribute to risk at a common location;

(3) Lead to better understanding of the nature of the threat, the failure mechanisms, the effectiveness of currently deployed risk mitigation activities, and how to prevent, mitigate, or reduce those risks;

(4) Account for, and compensate for, uncertainties in the model and the data used in the risk assessment; and

(5) Evaluate the potential risk reduction associated with candidate risk reduction activities such as preventive and mitigative measures and reduced anomaly remediation and assessment.

(d) *Plastic transmission pipeline.* An operator of a plastic transmission pipeline must assess the threats to each covered segment using the information in sections 4 and 5 of ASME B31.8S, and consider any threats unique to the integrity of plastic pipe **such as poor joint fusion practices, pipe with poor slow crack growth (SCG) resistance, brittle pipe, circumferential cracking, hydrocarbon softening of the pipe, internal and external loads, longitudinal or lateral loads, proximity to elevated heat sources, and point loading.**

(e) *Actions to address particular threats.* If an operator identifies any of the following threats, the operator must take the following actions to address the threat

> Per GPAC Vote (Slide 63, Bullet #3), PHMSA will "provide a 3-year phase-in period for risk assessments to meet the functional objectives specified in (c)."

> The Associations maintain that subject matter experts, including those that have attended PHMSA's Risk Modeling Work Group Meetings, have advised against attempting to model "worst case scenarios." (See Mr. Leewis's comments from the November 30 – December 1, 2016 PHMSA RMWG Meeting. Page 6 of the Meeting Minutes). Section 192.917(c) creates the obligation to consider consequences, including low-likelihood, high-consequence events.

> While the Associations agree that risk assessment generally lead to better understanding of risk, including prevention and mitigation, it is inappropriate for the regulation to require ("must") that risk assessment "lead to better understanding. How would "understanding" be documented/enforced?

> Per GPAC Vote (Slide 68), the GPAC supports PHMSA's proposed modifications to §192.917(d).

(1) *Third party damage.* An operator must utilize the data integration required in paragraph (b) of this section and ASME/ANSI B31.8S, Appendix A7 to determine the susceptibility of each covered segment to the threat of third party damage. If an operator identifies the threat of third party damage, the operator must implement comprehensive additional preventive measures in accordance with §192.935 and monitor the effectiveness of the preventive measures. If, in conducting a baseline assessment under §192.921, or a reassessment under §192.937, an operator uses an internal inspection tool or external corrosion direct assessment, the operator must integrate data from these assessments with data related to any encroachment or foreign line crossing on the covered segment, to define where potential indications of third party damage may exist in the covered segment.
An operator must also have procedures in its integrity management program addressing actions it will take to respond to findings from this data integration.

(2) *Cyclic fatigue.* An operator must evaluate whether cyclic fatigue or other loading conditions (including ground movement, suspension bridge condition) could lead to a failure of a deformation, including a dent or gouge, crack, or other defect in the covered segment. The evaluation must assume the presence of threats in the covered segment that could be exacerbated by cyclic fatigue. An operator must use the results from the evaluation together with the criteria used to evaluate the significance of this threat to the covered segment to prioritize the integrity baseline assessment or reassessment. ~~**Fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis must be conducted in accordance with § 192.624(d) for cracks.**~~ Cyclic fatigue analysis must be **validated periodically based on changes** ~~**performed**~~ **to pipeline operating or load conditions, not to exceed every seven years.** ~~**annually, not to exceed 15 months**~~.

The Associations encourage PHMSA to review the reference to the Fracture Mechanics requirements in §192.917(e)(2) when discussing MAOP Reconfirmation requirements (§192.624(d)).

The reference specifically to fracture mechanics modeling in the Integrity Management section is problematic, because §192.624(d) addresses fracture mechanics for only a particular pipeline segment and cracking situation. In proposed §192.917(e)(2), the cyclic fatigue analysis requirement is appropriate and sufficient to address the threat.

Per GPAC Vote (Slide 75), PHMSA will "revise §192.917(e)(2) based on GPAC discussion and considering PHMSA's proposed language at the meeting.

Mr. Nanney stated "what if we all considered confirm the cyclic fatigue analysis is valid periodically based on any changes to cyclic fatigue or other loading conditions not to exceed seven years." (6/7/2017 Transcript. Page 106. Line 17).

B. Proposed Changes to §192.917(e)(3) & (4): Industry Comments

The Associations are concerned that the interaction between §192.917(e)(3), which addresses manufacturing & construction defects, with the proposed MAOP Verification requirements in §192.624 has not been fully considered. The Associations continue to urge PHMSA to separate MAOP Reconfirmation from integrity management-related issues. The Associations believe this topic should be discussed in detail when MAOP Reconfirmation is addressed by the GPAC. The Associations will provide additional comments regarding the interaction between 192.624 and 192.917(e) after the GPAC discusses MAOP Reconfirmation (including 192.624).

C. Proposed Changes to §192.935(a): Incorporation of the GPAC Vote

The Associations provide the following suggested modifications to PHMSA's proposed §192.935(a). The Associations believe the modifications shown in **red** reflect the approved language as discussed at the June 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.

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

(a) *General requirements.* An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of failure in a high consequence area. Such additional measures must be based on the risk analysis required by 192.917, and must **consider** **and may** include~~,~~ ~~**but are not limited to**~~: correction of the root cause of past incidents to prevent reoccurrence; establishing and implementing adequate operations and maintenance processes that could increase safety; establishing and deploying adequate resources for successful execution of preventive and mitigative measures; installing Automatic Shut-off Valves or Remote Control Valves; installing pressure transmitters on both sides of automatic shutoff valves and remote control valves that communicate with pipe control center; installing computerized monitoring and leak detection systems; replacing pipe segments with pipe of heavier wall thickness or higher strength; conducting additional right of way patrols; conducting hydrostatic tests in areas where material has quality issues or lost records; tests to determine material mechanical properties for unknown properties that are need to assure integrity or substantive MAOP evaluations including material property tests from removed pipe that is representative of the in-service pipeline; re-coating of damaged, poorly performing or disbonded coatings; applying additional depth-of-cover survey at roads, streams, and rivers, remediating inadequate depth of cover; providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs.

> Per GPAC Vote (Slide 81, Bullet #2), PHMSA will "clarify that it is not PHMSA's intent to require that all listed P&M measures be implemented (& that 'must consider' will be instituted)."
>
> The Associations recommend adding "and may include" to emphasize that operators **must *consider*** these P&M measures, but not implement all measures.

V. Verification of Pipeline Materials: Onshore Steel Transmission Pipelines (§192.607)

During the June 2017 GPAC meeting, the committee members discussed the importance of separating two discrete activities that are currently jointly addressed in PHMSA's proposed regulatory requirement for Material Verification (proposed §192.607)[16]. These two separate activities are: (1) MAOP Reconfirmation for pipelines that do not have traceable, verifiable, and complete records supporting the current MAOP, including previously-untested pipe[17] and (2) application of Integrity Management principles. **While accurate material property data is necessary to support both MAOP Reconfirmation and Integrity Management, these are distinct processes that should be addressed separately in the Part 192 regulations.** These distinct processes often require different data, and the data is used in different ways.

The Associations maintain that MAOP Reconfirmation is a one-time effort focused on confirming the material strength of pipeline segments that do not have traceable, verifiable, and complete records supporting the current MAOP. MAOP Reconfirmation ensures that there is an initial safety margin for the operation of the pipeline at a safe pressure. At a future meeting, the GPAC will discuss when MAOP Reconfirmation is required, and the methods by which an operator can perform MAOP Reconfirmation. Following the establishment or reconfirmation of MAOP, the integrity of the pipeline, thereafter, is managed through ongoing operations, maintenance and integrity management activities. Integrity Management represents a much broader program than a program to reconfirm MAOP. An Integrity Management program must continually assess, manage and reduce pipeline risk. Integrity Management principles and regulations focus on all threats to a pipeline segment, and this is very different and separate from MAOP Reconfirmation to address the specific issue of records to confirm material strength.

Based on the feedback provided to PHMSA during the GPAC meeting, and pending further discussion on the efficacy of the proposed PHMSA MAOP Reconfirmation methods and potential alternatives, the Associations recommend that PHMSA consider the following approach for separating the Material Verification requirements associated with MAOP Reconfirmation from the Material Verification requirements associated with Integrity Management. This could be done through the following approach:

1) **Move proposed §192.607 (Verification of Pipeline Material) to proposed §192.624(c)(3) (MAOP Verification – Method 3: Engineering Critical Assessment),**
2) The changes to Subpart O (192.917 (a) & (b)) approved during the June 2017 GPAC meeting sufficiently outline the required material attributes needed to effectively identify and evaluate potential threats,
3) **Material data/records needed to support anomaly response and remediation calculations (e.g., remaining strength, predicted failure pressure) should be addressed within those respective sections.**

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[16] Regarding separating the material verification required for MAOP reconfirmation from that required for Integrity Management, examples of the GPAC Members' comments include, but are not limited to:

- Member Drake (6/7/2017 Transcript. Pages 201-204): "…I think, that's happening here is, we're trying to address a lot of issues in one place. And I think we convoluted a lot of issues here. There's really a couple of issues on the table that we need to keep deliberately separate. One is MAOP confirmation, which is a one-time event, and integrity management, which is a reoccurring event that happens many times in a pipe's lifetime. We've mangled those together and they're actually in one section of the code that's retroactive. And it's, I think it's creating a very fundamental rift among us about, how does this work?"
- Member Allen (6/7/2017 Transcript. Pages 254-255): "I get now what Andy was saying about, we need to separate establishment of MAOP, the information for establishing MAOP, and integrity management. And there's a lot of information here in (c) that is not required for establishing MAOP.... I get it now and I think you're right. I think that we are trying to fit a square peg in a round hole here, it's more than what's needed."
- Member Turpin (6/7/2017 Transcript. Pages 281-282): "So, it just seems like for a lot of the stuff we heard from the committee, a lot of stuff we've heard from the public, everybody tends to have the same identification of the fundamental issue which is Congress to go out and revisit MAOP, how do we do that, and there's the ongoing how do you continue to manage the integrity of your pipeline….you put everything in one bucket, for what looks like ease of execution…but that's [not how] it came across to most people who read it. Because I think when my staff went through this as well, we had concerns over this is going to end up having people take a lot of pipeline segments repeatedly out of service and have pretty large impacts to good reliability and deliverability."

PHMSA should remove the references to proposed § 192.607 within §§ 192.485(c), 192.624(d), 192.713(d), 192.929(b), 192.933(a)&(d). PHMSA and the GPAC should discuss what data/records are needed to support anomaly response and remediation calculations during the "Repair Criteria" topic at a later GPAC meeting.

A. Material Verification Needed to Support MAOP Reconfirmation

In the NPRM, PHMSA proposes a regulatory requirement for MAOP Reconfirmation for certain pipeline segments located in HCAs, Class 3 and Class 4 areas, and MCAs (proposed §192.624). In that proposal, PHMSA outlines six methodologies for MAOP Reconfirmation when an operator does not have traceable, verifiable, and complete records supporting the current MAOP. The efficacy of these six methodologies and discussion of potential alternatives will be raised at a later GPAC meeting and the Associations intend to provide comments at that time. Although the Associations still have some concern regarding the necessity for section 192.607, pending further discussion on MAOP Reconfirmation methodologies and potential alternatives at a future GPAC meeting, in these comments the Associations are addressing concerns directly related to the Material Verification to support PHMSA's currently-proposed MAOP Reconfirmation methods.

MAOP Reconfirmation *Method 1: Pressure Test* within proposed §192.624(c) involves physically raising the pressure in the pipeline to a margin of safety above the MAOP. When an operator performs MAOP Reconfirmation using *Method 1*, the operator will retain traceable, verifiable, and complete records of the pressure test.

Method 2: Pressure Reduction and *Method 5: Pressure Reduction for Segments with Small Potential Impact Radius and Diameter* involve reducing MAOP by a PHMSA-specified percentage based on historical operating data and *Method 4: Pipe Replacement* is pipe replacement, so Material Verification is not needed to support these MAOP Reconfirmation methods. *Method 6: Alternative Technology* provides a process for using an alternative technical evaluation for establishing MAOP; material data/records may be necessary to support MAOP reconfirmation using *Method 6*, but the plan for collecting and/or verifying that data would be specific to the alternative technology being utilized.

PHMSA's proposed §192.624(c) also provides *Method 3: Engineering Critical Assessment (ECA)*, which proposes a prescriptive engineering assessment process for establishing the material strength of the pipeline segment and reconfirming MAOP. If an operator chooses to utilize *Method 3* for MAOP Reconfirmation, the Associations agree that certain material documentation is essential for conducting the ECA, and that Material Verification should be required if certain traceable, verifiable, and complete material documentation is not available. Proposed §192.607 directly addresses material data needs to support MAOP Reconfirmation using *Method 3*[18].

Therefore, pending additional GPAC discussion on potential MAOP Reconfirmation alternatives that also address Material Verification, the Associations **propose §192.607 be relocated.** The Associations suggest that Material Verification requirements to support MAOP Reconfirmation should **instead be included within the proposed Engineering Critical Assessment method for MAOP Reconfirmation, §192.624(c)(3)**. The Associations offer the revised proposed regulatory code language below to demonstrate how this change can be realized. Later in these comments, the Associations provide further recommendations regarding the material data needs associated with Integrity Management and anomaly response and remediation. The Associations also suggest the following modifications to the PHMSA proposed regulatory language (in **blue** below), based on the GPAC discussions and public comment during the June 2017 meeting:

[18] The Associations may provide detailed comments on the various MAOP Reconfirmation methods after the GPAC discusses proposed 192.624. The intent of these comments is only to address proposed 192.607 (Material Verification).

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

(c) Maximum Allowable Operating Pressure Determination….

[…]

(3) *Method 3: Engineering Critical Assessment…*

[…]

(v) *Material Documentation*. To utilize this method, ~~Each~~ operators must have ~~reliable,~~ traceable, verifiable, and complete records documenting the following:

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

(B) 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;~~

(C) 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;~~

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

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

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

(B) Develop and implement procedures for conducting 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

Per *Approved Voting Slides*, the GPAC voted to retain the “traceable, verifiable, and complete” records standard without the term “reliable.”

At several instances, GPAC representatives described that, in lieu of a pressure test, *diameter, wall thickness, grade* or *yield strength,* and *longitudinal seam type* or *longitudinal seam factor* are the records needed to reconfirm MAOP. See comments of Mr. Nanney on pp. 153 of the June 7 transcript and Member Zamarin on pp. 251 regarding coating type, Member Zamarin on pp. 251 - 253 regarding ultimate tensile strength and manufacturing specification, Mr. Acuna on pp. 270 and Member Zamarin on 295 regarding chemistry.

For valves and flanges, PHMSA agreed to consider deleting the requirements associated with weld end bevel conditions, due to the impractically of collecting this data on installed pipes. See comments of Mr. Nanney on pp. 166 of June 7 transcript. TVC records of applicable manufacturing standards, manufacturing rating, or pressure rating are sufficient for MAOP reconfirmation.

(C) 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 activities that are in compliance with § 192.614, until completion of the number of excavations determined to be necessary by the operator though statistical analysis. ~~minimum number of excavations as follows.~~

~~(1) 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).~~

~~(2) For each population defined according to (i) above, the minimum number of excavations at which line pipe must be tested to verify pipeline material properties is the lesser of 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. The mileage for this calculation is the cumulative mileage of pipeline segments in the population without reliable, traceable, verifiable, and complete material documentation.~~

~~(C) 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 population would require 15 excavations for each 20 miles.~~

PHMSA agreed to consider deleting the requirement for testing when the pipe is exposed for "any other reason." (6/7/17 transcript, Page 169.) The Associations that it may not be possible or appropriate to conduct tests at every excavation.

It is the Associations' position that an operator's Engineering Critical Analysis for MAOP Reconfirmation should utilize and document statistical analysis(es) to determine an appropriate number of excavations necessary for reliably verifying material properties. The proposed minimum number of excavations is overly prescriptive. During the GPAC meeting, several commenters pointed out that operators had already begun material verification prior to publication of the NPRM, and would not have been aware of PHMSA's specific proposed process. Allowing operators to utilize statistical analysis to support their excavation frequency helps avoid spending resources on re-work where TVC records already exist. See comments of Ms. Aslinger on pp. 276 – 277 and Mr. Morton on pp. 301 – 302 of the June 7 transcript.

The Associations maintain that requiring operators to define separate populations of pipeline segments for each combination of undocumented attributes in an overly burdensome exercise that does nothing to further pipeline safety. Operators will identify specific segments that are missing documentation for specific attributes, but identification of unique populations is unnecessary.

(1) At each excavation **where pipe is removed,** tests for material properties must determine diameter, wall thickness, yield strength, ~~ultimate tensile strength,~~ Charpy v-notch **or comparable measure of** toughness (where required for **crack** failure pressure and ~~crack~~ growth analysis), ~~chemical properties~~, **and longitudinal** seam type **or longitudinal seam factor**, ~~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. Determination of material property values must conservatively account for measurement inaccuracy and uncertainty. ~~based upon comparison with destructive test results using unity charts.~~

(2) 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 **to conservatively account for measurement inaccuracy and uncertainty based upon comparison with destructive test results, including control measures such as unity charts**. ~~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 percentage for the grade of steel being tested.~~

(3) The minimum number of test locations at each excavation or above-ground location is based on **the number of excavations determined to be necessary by the operator through statistical analysis** ~~the number of joints of line pipe exposed, as follows:~~

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

It is the Associations' position that an operator's Engineering Critical Analysis for MAOP Reconfirmation should document the destructive and/or non-destructive tests necessary for verifying the necessary material properties. Not all excavations will involve pipe removal or destructive testing, which may be necessary for some of the material properties listed in this section. So, the Associations recommend this section only apply when an operator removes pipe. The reference to unity plots should be relocated to the proceeding section, where NDE methods for strength testing are discussed.

See comments of Mr. Nanney on pp. 153 of the June 7 transcript and Member Zamarin on pp. 251 regarding coating type, Member Zamarin on pp. 251 - 253 regarding ultimate tensile strength, Mr. Acuna on pp. 270 and Member Zamarin on 295 regarding chemistry.

The Associations maintain that an operator's Engineering Critical Analysis for MAOP Reconfirmation should utilize and document statistical analysis(es) to determine an appropriate number of test locations at each excavation necessary for reliably verifying material properties. The proposed minimum number of test locations is overly prescriptive. PHMSA agreed to consider relaxing the requirement for a minimum number of test locations, see comments of Mr. Nanney on pp. 160 of the June 7 transcript.

~~(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.~~

(4) For non-destructive tests, at each test location, a set of material properties tests must be conducted in accordance with operator or service provider defined testing procedures. ~~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.~~

(5) For destructive tests, at each test location, a set of materials properties tests must be conducted in accordance with an applicable manufacturing specification, such as API Spec 5L. ~~on each circumferential quadrant of a test pipe cylinder removed from each location, for a minimum total of four tests at each location.~~

(6) If the results of all tests conducted in accordance with paragraphs (i) and (ii) verify that unknown material properties are consistent with all available information for each ~~population,~~ pipeline are more conservative than current assumptions (such as: thicker walled pipe, smaller diameter, or higher grade), then no additional excavations are necessary. However, if the test results identify line pipe with properties that are not ~~consistent with existing~~ as conservative as the current assumptions ~~expectations~~ based on all available information for each ~~population~~ pipeline, then the operator must modify their testing frequency to address these inconsistencies. ~~perform tests at additional excavations. The minimum number of excavations that must be tested depends on the number of inconsistencies observed between as-found tests and available operator records, in accordance with the table below:~~

The Associations suggest that there is no technical justification to support PHMSA's proposed requirement to complete a minimum of 20 readings at each location. PHMSA should require operators to adhere with the testing procedures supplied by the testing service providers. See comments of Mr. Bellemare on pp. 271 of the June 7 transcript.

Furthermore, the proposal that operators perform a destructive test on each circumferential quadrant is outdated and contrary to standard practice used today. Destructive tests should be completed in accordance with an applicable manufacturing specification. Without this modification, significant work that has already been completed will be negated. See comments of Mr. McWhorter on pp. 278.

Operators should not be deterred from making supported engineering assumptions that are conservative. The regulatory text should be revised to ensure that only results that are "less conservative" require further testing.

The Associations advocate that an operator's Engineering Critical Analysis for MAOP Reconfirmation should utilize and document statistical analysis(es) to determine the number of additional required excavations for each pipeline if test results identify line pipe with properties that are not as conservative as the current assumptions.

~~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)~~

~~(ix) The tests conducted for a single excavation according to the requirements of § 192.607(d)(3)(iii) through (vii) above count as one sample under the sampling requirements of § 192.607(d)(3)(i), (ii), and (viii).~~

(7) In the event that an operator determines another technology, such as in-line inspection, is capable of meeting the confidence levels established through §192.624(c)(3)(vi)(C)*(1)* or §192.624(c)(3)(vi)(C)*(2)*, the Engineering Critical Analysis should reflect the use of this other technology. The technology must still be able to capture a statistically significant quantity of data for each pipeline for which material verification is being performed.

(D) For mainline pipeline components other than line pipe, the operator must develop and implement procedures for establishing and documenting the ANSI rating, where applicable, and material grade (to assure compatibility with pipe ends).

(1) 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.

(2) 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.

The Associations maintain that operators should be able to utilize ILI and other technology, if the operator's Engineering Critical Analysis for MAOP Reconfirmation documents the process by which the operator will use the technology to capture a statistically significant quantity of data for the pipeline and material attribute requiring verification. This technology should achieve the same confidence level established for other technologies as outlined above in §192.624(c)(3)(vi)(C)*(1)* & *(2)* above.

During the GPAC meeting (6/7/17 transcript, pp. 163), PHMSA agreed to add "where applicable" with respect to the ANSI rating, since not all components will have an ANSI rating.

During the 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.

(3) 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.

(E) 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.

~~**(F) If conditions make material verification by the above methods impracticable or if the operator chooses to use "other technology" or "new technology" (alternative technical evaluation process plan), the operator must notify PHMSA at least 180 days in advance of use in accordance with paragraph § 192.624(e) of this section. The operator must submit 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.**~~

The Associations recommend the alternative language provided above in §192.624(c)(3)(vi)(C)*(7).* To encourage the development and use of new technologies for material verification, ILI and other technology should be allowed in accordance with the operator's Engineering Critical Analysis for MAOP reconfirmation without requiring an operator to follow a protracted pre-notification and approval process.

B. Material Data Needed to Support Integrity Management

As discussed during the June 2017 GPAC meeting[19], ASME B31.8S-2004 outlines the material attributes which are required to effectively identify and evaluate the potential threats to a covered pipeline segment. These data gathering and integration requirements are already codified in Subpart O of Part 192 (See §192.917 where ASME B31.8S is incorporated by reference). As discussed during the GPAC meeting[20], Table 1 of ASME B31.8S – 2004 (reproduced below) lists the 40 "Data Elements for Prescriptive Pipeline Integrity Program." Furthermore, PHMSA's proposed changes to §192.917(b), which the committee approved at the June 2017 GPAC meeting, prescriptively incorporate Table 1 from B31.8S – 2004 and outlines the material attributes and other relevant information/data that operators must integrate into their risk management program. This regulation even requires operators to gather and integrate data on non-covered segments. Most importantly, the ASME B31.8S – 2004 standard also provides direction to operators in responding to missing data.

Therefore, the Associations believe it is unnecessary and confusing to introduce the additional Material Verification program outlined in proposed §192.607 to integrity management activities. The proposed Material Verification program should only apply to the data/records necessary to reconfirm MAOP using *Method 3* of proposed §192.624(c). As outlined above, PHMSA should **relocate the relevant language within the proposed §192.607 to proposed §192.624(c)(3) (MAOP Verification – Method 3: Engineering Critical Assessment).**

Table 1 Data Elements for Prescriptive Pipeline Integrity Program

Category	Data
Attribute data	Pipe wall thickness
	Diameter
	Seam type and joint factor
	Manufacturer
	Manufacturing date
	Material properties
	Equipment properties
Construction	Year of installation
	Bending method
	Joining method, process and inspection results
	Depth of cover
	Crossings/casings
	Pressure test
	Field coating methods
	Soil, backfill
	Inspection reports
	Cathodic protection installed
	Coating type
Operational	Gas quality
	Flow rate
	Normal maximum and minimum operating pressures
	Leak/failure history
	Coating condition
	CP (cathodic protection) system performance
	Pipe wall temperature
	Pipe inspection reports
	OD/ID corrosion monitoring
	Pressure fluctuations
	Regulator/relief performance
	Encroachments
	Repairs
	Vandalism
	External forces
Inspection	Pressure tests
	In-line inspections
	Geometry tool inspections
	Bell hole inspections
	CP inspections (CIS)
	Coating condition inspections (DCVG)
	Audits and reviews

[19] For some discussion of the extensive set of material attributes required by ASME B31.8S and approved by the GPAC as part of 192.917(b) at the June meeting, see comments of Mr. Nanney on pp. 329 – 333 of the June 6 transcript.

[20] Mr. Nanney (6/7/2017 Transcript. Pages 15): "Also, 917(b)(1) is intended to reflect the set of data specified in Table 1 in Appendix A of B31.8S and existing 917(b)(1) plus the addition of seismicity-related data to implement the congressional mandate of the 2011 Act."

C. Material Verification Needed to Support Response and Remediation Criteria

The NPRM also references proposed §192.607 in several new code sections or proposed modifications to existing code sections related to anomaly response and remediation (§§ 192.485(c), 192.624(d), 192.713(d), 192.929(b), 192.933(a)&(d)). PHMSA should remove the references to §192.607 within these sections. **As has been discussed numerous times in previous PAC meetings, record requirements should be discussed directly in the sections related to those records. This provides clarity for the operator and the regulator. Therefore, data/records needed to support anomaly response and remediation calculations (e.g., remaining strength, predicted failure pressure, etc.) should be addressed separately within the appropriate sections.** The GPAC should discuss what data/records are needed to support anomaly response and remediation calculations (e.g., remaining strength, predicted failure pressure, etc.) when it reaches the "Repair Criteria" topic at a later GPAC meeting.

Removing the references to proposed §192.607 within the anomaly response and remediation sections *does not* prevent PHMSA from establishing a separate obligation, within the sections listed in the previous paragraph, for operators to obtain, document, and retain data needed to support these important integrity-related calculations. The Associations propose that the required parameters for metal loss anomaly response calculations are grade, diameter, wall thickness and longitudinal seam factor. Similarly, for crack like features, the required parameters for metal loss anomaly response calculations are grade, diameter, wall thickness, longitudinal seam factor and toughness. The Associations will provide further comments on how to address the §192.607 references within the "Repair Criteria" sections after those sections have been discussed by the GPAC at a later meeting.

Respectfully submitted,
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