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 JANUARY 11 – 12, 2017

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

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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 Gas Pipeline Advisory Committee (GPAC) meeting that occurred on January 11-12, 2017.[4]

The meeting provided the GPAC Members, PHMSA representatives, the regulated community, and the public with the opportunity to discuss several topics contained within PHMSA's Safety of Gas Transmission and Gathering Pipelines (Proposed Rule).[5] In many respects the meeting produced a clear and substantive direction on how to ensure that a specific topic is finalized in a manner that is technically feasible, reasonable, cost-effective, and practicable. In particular, the GPAC discussions clearly articulated that proposals pertaining to gathering lines must be addressed in a separate, dedicated GPAC meeting. For other topics, the conversations made strides in identifying concerns, but left much to be resolved during later meetings. Given the technical and complicated nature of the subject matter, and the sheer breadth of topics discussed, the Associations believe it is appropriate to provide PHMSA and the GPAC members with the following comments,[6] which are intended to summarize the views expressed, elaborate on the concerns identified, and provide the appropriate context for many of the discussions. 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: Meeting of the Gas Pipeline Safety Advisory Committee, 81 Fed. Reg. 83795 (November 22, 2016). 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.

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

[6] Each Association submitted to PHMSA detailed substantive comments on PHMSA's Safety of Gas Transmission and Gathering Pipelines Proposed Rule. The comments made in this submittal in no way replace each Association's individual comments, but are intended to supplement any prior-filed comments.

II. TIMP REASSESSMENT INTERVALS

A. Industry Suggestion: Addressing §192.939(b)

Section 5 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 made a technical correction to the Pipeline Safety Act to allow pipeline operators to conduct periodic reassessments of facilities under the integrity management program at a minimum of once every 7 calendar years.[7] The Proposed Rule would codify the new statutory reassessment interval at §192.939(a),[8] and the GPAC endorsed that proposal at the January meeting.[9] However, the Proposed Rule did not contain a corresponding change to the reassessment interval in §192.939(b) for pipelines operating below 30% specified minimum yield strength (SMYS). The new statutory reassessment interval is a self-executing congressional mandate that can be added to Part 192 without further notice or comment, and the Associations suggest that the GPAC consider the following amendment at the next meeting:

> *§192.939 What are the required reassessment intervals?*
>
> (b) *Pipelines Operating below 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating below 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven **calendar** years. **Operators may request a six-month extension of the seven-calendar year reassessment interval if the operator submits written notice to OPS in accordance with §192.949, with sufficient justification of the need for the extension.** An operator must establish reassessment by at least one of the following –
>
> (1) Reassessment by pressure test, internal inspection or other equivalent technology following the requirements in paragraph (a)(1) of this section except that the stress level referenced in paragraph (a)(1)(ii) of this section would be adjusted to reflect the lower operating stress level. If an established interval is more than seven **calendar** years, the operator must conduct by the seventh **calendar** year of the interval either a confirmatory direct assessment in accordance with §192.931, or a low stress reassessment in accordance with §192.941.

[7] 49 U.S.C. § 60109(c)(3)(B).

[8] 81 Fed. Reg. 20,722, at 20,848.

[9] Transcript of PHMSA GPAC Meeting, 160:12-162:17 (January 12, 2017). .

III. CONTINUING SURVEILLANCE AFTER WEATHER EVENTS

A. Redline Code: Suggested Changes to Proposed §192.613

The GPAC voted on concepts, rather than specific language, when reviewing the requirements for inspecting pipeline facilities after extreme weather events in the Proposed Rule. The Associations expect that specific language will be offered at the next GPAC meeting and provide the following modifications to PHMSA's proposed § 192.613(c) for consideration:

§192.613 Continuing surveillance.

(c) Following an extreme weather event such as a hurricane or flood, an earthquake, landslide, a natural disaster, or other similar event that has the likelihood of **significant** damage to **pipeline facilities** ~~infrastructure~~, an operator must inspect all potentially affected onshore transmission pipeline facilities to detect conditions that could adversely affect the safe operation of that pipeline.

> The Associations recommend that the qualifier "significant" be added to the regulatory text as discussed during the first GPAC Meeting. (1/11/17 Transcript. Page 83. Line 8.)

> Per the GPAC vote, bullet #4, PHMSA will "change the word 'infrastructure' to 'facilities' per the presentation slides."

(1) Inspection method. An operator must consider the nature of the event and the physical characteristics, operating conditions, location, and prior history of the affected pipeline in determining the appropriate method for performing the initial inspection to determine damage and the need for the additional assessments required under the introductory text of paragraph (c) in this section.

> The Associations ask PHMSA to clarify in the preamble of the Final Rule that the requirement to *inspect* pipelines is not a requirement to perform in-line *inspection* on the pipeline.

(2) Time period. The inspection required under the introductory text of paragraph (c) of this section must commence within 72 hours after ~~the cessation of the event, defined as~~ the point in time when the affected area can be safely accessed by ~~the~~ personnel and equipment **and the**, ~~including availability of~~ personnel and equipment required to perform the inspection as determined under paragraph (c)(1) of this section **are available.**~~, whichever is sooner.~~

> Per the GPAC vote, bullet #1, PHMSA will "clarify that the timing in 192.613(c) begins after the operator has made a reasonable determination that the area is safe", and, bullet #3, "delete 'whichever is sooner' at the end of 192.613(c)(2)." The Associations suggest the associated revisions.

(3) Remedial action. An operator must take appropriate remedial action to ensure the safe operation of a pipeline based on the information obtained as a result of performing the inspection required under the introductory paragraph (c) in this section. Such actions might include, but are not limited to:

(i) Reducing the operating pressure or shutting down the pipeline;
(ii) Modifying, repairing, or replacing any damaged pipeline facilities;
(iii) Preventing, mitigating, or eliminating any unsafe conditions in the pipeline right-of-way;
(iv) Performing additional patrols, surveys, tests, or inspections;
(v) Implementing emergency response activities with Federal, State, or local personnel; or
(vi) Notifying affected communities of the steps that can be taken to ensure public safety.

B. Comparison: Proposed Appendix A (Summary of Regulatory Requirements) to Regulatory Text

PHMSA included two recordkeeping requirements in Appendix A of the Proposed Rule for conducting continuing surveillance after weather events. As described below, the Associations believe

that PHMSA should more accurately identify the regulatory sections that pertain to the recordkeeping requirements .

- Section 192.613(c)(1), Records of inspections performed following extreme events. Based on PHMSA's proposed regulations, the obligation to perform an inspection arises generally under §192.613(c), not §192.613(c)(1), which describes the inspection methods to be considered. Moreover, there is no express recordkeeping requirement in this proposed regulation. PHMSA should make clear that the obligation to maintain these records arises under the general recordkeeping requirement for operations and maintenance related inspections in §192.709(c). The Associations also believe that the retention time described in Appendix A should be revised from "5 years" to "5 years or until the next patrol, survey, inspection or test is completed."[10]
- Section 192.613(c)(3), Records of remedial actions. The Proposed rule did not include an express record-keeping requirement in this proposed regulation. PHMSA should clarify that any obligation to maintain records arises under either (1) §192.709(a) or (b) and would be limited to records of the date, location and description of any repairs made, or (2) §192.709(c) and would be limited to records of additional patrols, surveys, inspections and tests.

[10] 49 C.F.R. § 192.709(c).

IV. MANAGEMENT OF CHANGE

A. Redline Code: Suggested Changes to Proposed §192.13(d)

The Associations provide the following suggested modifications to PHMSA's proposal to §192.13(d) in the Proposed Rule. These modifications are based on the discussions that occurred at the January meeting.

§192.13 What general requirements apply to pipelines regulated under this part?

(d) Each operator of an onshore gas transmission pipeline must evaluate and mitigate, as necessary, **significant changes that pose a risk to safety or the environment through a management of change process.** ~~**risks to the public and environment as an integral part of managing pipeline design, construction, operation, maintenance, and integrity, including management of change.**~~ Each operator of an onshore gas transmission pipeline must develop and follow a management of change process, as outlined in ASME/ANSI B31.8S, section 11, that addresses technical, design, physical, environmental, procedural, operational, maintenance, and organizational changes to the pipeline or processes, whether permanent or temporary. A management of change process must include the following: (1) reason for change, (2) authority for approving changes, (3) analysis of implications, (4) acquisition of required work permits, (5) documentation, (6) communication of change to affected parties, (7) time limitations and (8) qualification of staff. **For segments other than those covered in Subpart O of this part, this management of change process must be implemented within two (2) years of [*insert Effective Date of Final Rule*]. This section only applies to gas transmission pipelines.**

Per the GPAC vote, bullet #2, PHMSA will "clarify the requirement only covers significant changes that affect safety and environment."

Per the GPAC vote, bullet #1, "for non- IM assets, provide a 2-year phase-in period with notification procedures for justified extensions."

Per the GPAC vote, bullet #3, PHMSA will "clearly state that distribution and gathering lines are exempt."

V. RECORDS

The Associations are committed to ensuring that decisions related to pipeline safety and operations are based on facts and conservative assumptions that can be validated and supported. The Associations provide these comments to provide additional context for several of the concerns raised during the first GPAC meeting regarding records.

A. Industry Position: Concerns with §192.13(e)

Section 192.13(e) in the Proposed Rule would add a new general duty to document compliance with all aspects of Part 192, in addition to any explicit recordkeeping requirement already included in the pipeline safety regulations. Many of the concerns with Section 192.13(e) are related to PHMSA's proposed placement of this section in a retroactive subpart of Part 192, which has an overreaching effect throughout Part 192. As discussed at the GPAC meeting, the requirement to maintain records should be topic-specific, and the new retention requirements listed in Appendix A should apply prospectively only. For example, PHMSA should include any recordkeeping requirements for MAOP in subpart L and not in a general section of the code.

Based on the discussion at the GPAC meeting, PHMSA agreed to reevaluate the need for §192.13(e).[11] The Associations request that PHMSA consider the following concerns as part of that process:

Proposed §192.13(e) states "Each operator must make and retain records that demonstrate compliance with this part." This requirement imposes a general duty on operators of transmission and distribution lines to document compliance with Part 192, even in the absence of a specific recordkeeping requirement. The Associations agree with suggestions at the GPAC meeting that PHMSA identify the needs for specific records and address recordkeeping requirements within specific sections of Part 192. As indicated by PHMSA during the GPAC, this section does not apply to gathering lines.

PHMSA has proposed three standalone subsections of § 192.13: §§192.13(e)(1), 192.13(e)(2), and 192.13(e)(3). As drafted, each subsection has independent application to pipelines.

§192.13(e)(1): The first subsection requires transmission pipeline operators to comply with Appendix A. During the GPAC meeting, PHMSA described its intent for Appendix A to be a compilation of record keeping requirements for transmissions pipelines in one location.[12] The Associations always appreciate PHMSA's attempts to provide clarity in regulatory requirements. Our concerns with Appendix A, however, are that PHMSA's summary of recordkeeping requirements adds new record retention requirements and is often inconsistent with the text of the cited regulatory provision. Based on the GPAC and PHMSA's decision to address record requirements within each topic, the Associations will address their specific concerns with Appendix A during the appropriate topic-specific discussion. If the GPAC supports keeping Appendix A, it should be illustrative in nature and serve only as a source of guidance on the recordkeeping requirements imposed elsewhere in Part 192.

In general, the Associations are concerned that Appendix A does not clearly identify the origin of record requirements and overstates regulatory requirements to maintain records. PHMSA should clarify that the new retention requirements listed in Appendix A apply prospectively only. The non-retroactivity provision in the Pipeline Safety Act not only applies to the substantive safety standards relating to the

[11] Transcript 212:22-213:9.
[12] Transcript 165:18-167:1.

design, installation, construction, initial inspection, and initial testing of gas pipeline facilities, but it also applies with equal force and effect to the related record requirements.

§192.13(e)(2): The second subsection imposes a "reliable, traceable, verifiable, and complete" standard on all records. This subsection is not limited to transmission pipelines, but would require that all records required by Part 192, for both transmission and distribution pipelines, be reliable, traceable, verifiable, and complete. As discussed in the GPAC, the term "reliable" is new and should be eliminated. PHMSA itself acknowledged that the term is not necessary,[13] and suggested they would remove it from the phrase.[14]

PHMSA should also consider limiting the application of the traceable, verifiable, and complete (TVC) standard to those records of utmost importance, namely records used to support MAOP determinations for transmission pipelines. PHMSA has failed to include a reasoned basis to support its overbroad application of TVC to all records. Section 23 of the 2011 Act required verification only of records used to establish MAOP and pipeline operational and physical characteristics.[15] By imposing the standard broadly across all of Part 192, PHMSA has diminished the importance of the TVC standard.

The Associations strongly encourage PHMSA to provide a regulatory definition for "traceable, verifiable, and complete." The Associations suggest the following definition,[16] which is based on PHMSA's 2012 Advisory Bulletin and follow up clarifications on the meaning of the phrase:

> *Traceable, verifiable, and complete means that a single record or a combination of records:*
>
> *(1) can be linked to original information about a pipeline segment or facility and is finalized as evidenced by a signature, date, or other appropriate marking or*
>
> *(2) has other similar characteristics that support its validity.*
>
> *A single record can be traceable, verifiable, and complete. However, in some situations, complementary, but separate, documentation may be necessary. In determining whether a record is traceable, verifiable, and complete, due consideration shall be given to the standards and practices in effect at the time the record was created.*

§192.13(e)(3): The third section requires operators of pipelines for which records are not available to re-establish pipeline material documentation in accordance with PHMSA's proposed material verification requirements. This section is not limited to transmission pipelines, but would apply to both transmission and distribution pipelines. The language in Section 192.13(e)(3) could be read as expanding the applicability of the proposed material verification requirements found in §192.607 to all pipelines, even though the proposed language of §192.607 limits applicability to transmission pipelines in High Consequences Areas or located in Class 3 or Class 4 locations.

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[13] Transcript 176:16-22 (Comments by S. Nanney that the inclusion of the term "reliable" did not make "much difference to the standard.)

[14] Transcript 211:14-213:8 (Comments by A. Mayberry suggesting that PHMSA would remove the term "reliable.")

[15] 49 U.S.C. § 60139

[16] Even if PHMSA eliminates proposed Section 192.13(e), a definition of "traceable, verifiable, and complete" is necessary because PHMSA uses this phrase in other proposed record keeping sections.

The broad and ambiguous language of proposed §192.13(e), combined with the placement in a general and retroactive subpart, creates a host of unintended consequences and does nothing to advance or clarify PHMSA's specific record keeping requirements. The Associations encourage the elimination of proposed §192.13(e).

VI. CORROSION CONTROL

During the GPAC meeting, members recognized that substantial changes are being proposed to this complex and highly technical topic. The Associations recommend that the GPAC consider forming a Subcommittee to further analyze and discuss the details of these proposed changes, to assure that the most practical and efficient rule is being constructed that leverages all available technologies.

A. Redline Code: Suggested Changes to Proposed §192.319

The Associations provide the following suggested modifications to PHMSA's proposed §192.319(d). These modifications represent the discussion that occurred at the January GPAC meeting, as well as concerns shared by the public or identified through written comments 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, but not later than ~~three months~~ **one (1) year** after placing the pipeline in service, the operator must perform an **indirect** assessment **to ensure adequate corrosion control measures, such as: close interval survey, alternating current voltage gradient, direct current voltage gradient, or equivalent.** ~~to ensure integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG). 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.~~ **Remedial action must be completed promptly, but no later than one (1) year following the indirect assessment. If permits are necessary, remedial action must be completed promptly following 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**.

PHMSA stated during the GPAC meeting that one purpose of the three-month timeline requirement was to accomplish these assessments while the construction contract personnel are still onsite. However, different, specialized personnel are generally used to conduct indirect assessments, and more than three months is required for backfill and moisture to stabilize, in order to conduct an accurate assessment. (See 1/11 Transcript, Page 231.)

The effectiveness of corrosion control methods can be analyzed using a variety of technologies (other than voltage gradient surveys). Furthermore, regarding the proposed prescriptive voltage drop thresholds, requirements in current Subpart O and NACE standards direct operators to establish appropriate voltage drop thresholds requiring remediation, based on site-specific conditions. [This comment also applies to §192.461 and §192.935(g).]

As discussed during the GPAC meeting, designing a mitigation strategy, obtaining appropriate permits, and implementing the mitigation strategy can often take longer than 6 months. PHMSA has historically interpreted the requirement to remediate CP deficiencies "promptly" to mean 'before the next test interval.' The Associations believe a one-year time frame is generally achievable, unless the issuance of necessary permits is delayed. (See 1/11 Transcript, Pages 235, 247.) [This comment also applies to § 192.461, § 192.465, § 192.473, and § 192.935(g).]

B. Redline Code: Suggested Changes to Proposed §192.461

The Associations provide the following suggested modifications to PHMSA's proposed §192.461(f). These modifications represent the discussion that occurred at the January GPAC meeting, as well as well as concerns shared by the public or identified through written comments on the Proposed Rule. *§ 192.461 External corrosion control: Protective coating.*

(f) Promptly, but no later than ~~three months~~ **one (1) year** after backfill of an onshore transmission pipeline ditch following repair or replacement (if the repair or replacement results in ~~1,000 feet~~ **1 mile** or more of backfill length along the pipeline), conduct **an indirect assessment to ensure adequate corrosion control measures, such as: close interval survey, alternating current voltage gradient, direct current voltage gradient, or equivalent.** ~~surveys to assess any coating damage to ensure integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG). 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.~~ **Remedial action must be completed promptly, but no later than one (1) year following the indirect assessment. If permits are necessary, remedial action must be completed promptly following receipt of necessary permits.**

As discussed during the GPAC meeting, more consistent inspection presence is feasible on short replacements, so limiting this requirement to work involving 1 mile or more of backfill may be a more effective use of resources. (See 1/11 Transcript Pages 241, 302.)

See the comments on §192.319 for the remainder of the edits recommended by the Associations for this section.

C. Redline Code: Suggested Changes to Proposed §192.465

The Associations provide the following suggested modifications to PHMSA's proposed §192.465(d) and (f). These modifications represent the discussion that occurred at the January GPAC meeting, as well as well as concerns shared by the public or identified through written comments on the Proposed Rule.

§ 192.465 External corrosion control: Monitoring

(d) Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring, inspection and testing provided in paragraphs (a), (b) and (c) of this section. Remedial action must be completed promptly, but no later than the next monitoring interval in § 192.465 or within **15 months**. ~~one year, whichever is less.~~, **If permits are necessary, remedial action must be completed promptly following receipt of necessary permits.**

PHMSA has historically interpreted the requirement to remediate CP deficiencies "promptly" to mean 'before the next test interval.' If PHMSA does add a mandatory close interval survey (CIS) requirement for any annual CP test data deficiency, PHMSA should provide operators with 15 months to complete the associated remediation, because existing regulation allows annual CP tests to be conducted 'no later than 15 months apart.' It should be noted that evaluation and remediation is an ongoing process that may extend well past the

(f) For onshore 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) of this section. The operator 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 measured for electrical short to an adjacent foreign structure, rectifier connection or power source. 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, operators can perform**

Per NACE SP0207 (Sections 7.2.1 & 7.2.2), CIS intervals are calculated based on depth of cover and resistivity ratio. Closer spaced intervals may add no value. Therefore, the intervals should be determined by the operator for each line to be surveyed, not prescribed by regulation as 5 ft. maximum.

As discussed during the GPAC meeting, operators should be permitted to resolve rectifier shorts and similar malfunctions with above-ground equipment, if adequate cathodic protection is confirmed by repeating the pipe-to-soil potential survey. Additionally, if operators conduct remediation measures and confirm restoration of adequate CP through a CIS of the entire area, a reading at additional intervals between the test stations should not be required. (See 1/11 GPAC Transcript. Page 238. Line 11.)

a close interval survey following the remedial measures to confirm restoration of adequate cathodic protection.

E. Operator Case Study: Interference Mitigation

As discussed during the GPAC meeting, operators agree with the importance of monitoring for, preventing, and mitigating the effects of interference current on gas pipelines. That being said, there was significant discussion regarding the time needed to implement interference current remediation measures, including to obtain third-party data, design remediation measures, acquire permits, acquire land, and install and test the remediation measures. Therefore, the Associations provide the following examples to support future conversations.

Operator Case Studies: Impact of the Proposed Interference Current Mitigation Requirements

Operator Case Study 1

Gas Transmission Pipeline Operator

Pipeline segment in highly populated metropolitan area that is influenced by high voltage AC transmission power lines and the local subway.

Following the identification of a possible interference current with the potential to cause significant corrosion, the following actions were taken by the operator:

Date	Action	Explanation
August, 2010 – November 2010	Conducted CIS, DCVG, and dynamic stray current surveys	These actions were used to confirm whether anodes were installed per design, detect coating holidays, and account for all interference current sources
November 2010 – July 2011	Qualified personnel worked to develop a remediation plan	
August, 2011 – October 2011	Repeated survey work from previous year, during different times of day	Additional data was needed to develop the proper remediation plan
November 2011 – January 2012	Qualified personnel developed and proposed a remediation plan	
February 2012 – July 2012	Completed AC mitigation study. Pipeline Integrity team planned, scheduled, and budgeted for a variety of tasks for 2013: • Install AC mitigation anodes • Install CP test stations • Install electrical resistance probes • Conduct additional influence testing • Verify isolation • Conduct interference testing with nearby pipelines • Other resurveying	A multi-pronged approach was warranted to remediate and fully understand the causes and effects of the interference current.

June 2012 – March 2013	Assembled necessary information and applied for environmental permits in two (2) states	Environmental permits were needed to install the AC mitigation and CP remediation measures mentioned previously
October 2013 – December 2013	Received permits from State #1 and installed remediation equipment	
January 2014	Began weekly conference calls to monitor status of the State #2 permits	
March 2014	Considered redesigning remediation measures to avoid need for State #2 permits. Decided against this approach.	Extended time and substantial cost would have been necessary to redesign and install alternative remediation measures
October 2014	Received State #2 permits. Installed AC mitigation equipment on State #2 segment. Conducted additional CP testing on pipeline.	
March 2015	Identified sections where CP anodes were depleted, based on the additional testing completed in October 2014. Developed plan to remediate within 15 months.	
May 2015 – April 2016	Conducted additional testing and remediated CP anodes	
June 2016 – December 2016	Completed a follow-up AC interference current study, analyzed results, and planned additional remediation measures.	
January 2017	Submitted environmental permit applications to install additional AC interference current remediation measures	Follow-up study in 2016 identified need to complete additional remediation measures
Future (2017)	Perform additional CIS testing based on corrosion coupon data. Install additional AC interference remediation following receipt of necessary permits from both states.	

F. Redline Code: Suggested Changes to Proposed §192.473

The Associations provide the following suggested modifications to PHMSA's proposed §192.473(c). These modifications represent the discussion that occurred at the January GPAC meeting, as well as concerns shared by the public or identified through written comments on the Proposed Rule.

§ 192.473 External corrosion control: Interference currents.

(c) For onshore gas transmission pipelines, the program required by paragraph (a) must include:

(1) Interference surveys for a pipeline system to detect the presence and level of any electrical stray current. Interference surveys must be taken on periodic basis ~~including,~~ when **potential monitoring indicates a significant increase in stray current, or new potential stray current sources are introduced, such as** ~~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;

(2) Analysis of the results of the survey to determine the cause of the interference and whether the level could ~~impact the effectiveness of cathodic protection~~ **cause significant corrosion**; and

(3) Implementation of remedial actions to protect the pipeline segment from detrimental interference currents promptly but no later than~~six months~~ **one year** after completion of the survey. **If permits are necessary, remedial action must be completed promptly following receipt of necessary permits.**

The Associations recommend that PHMSA revise §192.473(c)(1) to be reflective of language consistent with NACE SP 0169-2013.

The Associations recommend that the analysis of the survey results of the interference currents are at the level where they may cause corrosion, versus impacting the cathodic protection system. Just because the CP system is impacted doesn't mean that there will be corrosion in every instance. Operators use layers of protection that include, but are not limited to, cathodic protection.

The Associations agree with public commenters at the first GPAC meeting that six months is an inadequate timeframe for operators to perform remedial actions in all cases. See the Operator Case Study provided in these comments that outlines the process and timeline that may be required to complete interference current remediation. [This comment also applies to §192.935(g).]

G. PHMSA Incident Data: Analysis of Internal Corrosion Reportable Incidents (1997-2016)

During the GPAC meeting, committee members discussed the importance of reviewing data for incidents caused by corrosion as a key input in determining what changes are appropriate to the existing corrosion control regulations. During that discussion, the number of 206 incidents attributable to internal corrosion between 2002 and 2012 was referenced. [17] This statistic originated in the preamble of the Proposed Rule when PHMSA introduced the proposed §192.478.[18] The Associations have reviewed historical data for PHMSA reported incidents caused by corrosion, and have provided the four summary tables below to support further discussions.

PHMSA provided number of 206 incidents is believed to be attributed to significant and serious internal corrosion related incidents occurring on both offshore and onshore natural gas transmission pipelines between 2002 and 2012. (See Table 1.) While this may be an important statistic for PHMSA to track, it is not appropriate for the Proposed Rule, which is limited in scope to onshore gas transmission pipelines. Therefore, including offshore incidents for the discussion on internal corrosion control requirements misrepresents the impacts of the Proposed Rule.

Table 1: All (*Onshore and Offshore*) Gas Transmission & Gathering Pipeline Incidents

EXTERNAL CORROSION																					
	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	**Total**
Annual Incident Count	5	8	4	15	7	5	11	11	14	13	17	14	9	9	4	13	5	10	11	6	**191**
INTERNAL CORROSION																					
	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	**Total**
Annual Incident Count	16	14	12	15	9	13	13	25	15	18	34	12	27	25	21	19	17	15	17	10	**347**

Note: The highlighted years are the source of PHMSA's statistic that 206 incidents attributable to internal corrosion occurred between 2002 and 2012. However, this statistic included incidents for offshore natural gas transmission pipelines, which are not addressed by this proposed rulemaking.

[17] Transcript 278:11 – 280:6

[18] 81 Fed. Reg. 20810.

Table 2: All *Onshore* Gas Transmission & Gathering Pipeline Incidents

EXTERNAL CORROSION TYPE

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	**Total**
Annual Incident Count	4	6	3	13	7	5	10	8	13	13	17	11	8	7	4	10	5	10	5	6	**165**

INTERNAL CORROSION CAUSE

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	**Total**
Annual Incident Count	9	6	7	8	6	4	6	3	5	8	9	5	8	7	9	4	7	3	10	5	**129**

Note: The majority of internal corrosion incidents occur in offshore pipeline systems; PHMSA's proposed changes to corrosion control and P&M requirements in Subpart I & Subpart O do not apply to offshore systems. PHMSA's statement in the NPRM that operators reported 206 incidents attributable to internal corrosion between 2002 and 2012 is not accurate for the onshore systems affected by this rulemaking (NPRM @ 20,810).

Table 3: All *Significant* Onshore Gas Transmission & Gathering Pipeline Incidents

EXTERNAL CORROSION

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	**Total**
Annual Incident Count	4	3	2	10	5	4	5	2	10	6	16	6	4	6	4	6	4	10	3	6	**116**

INTERNAL CORROSION

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	**Total**
Annual Incident Count	2	5	4	5	6	3	6	2	3	6	4	4	4	4	9	4	5	0	6	4	**86**

Significant incidents for gas transmission and gathering pipelines are those that involve either:

(f) A fatality or injury requiring in-patient hospitalization

(g) $50,000 or more in total costs, measured in 1984 dollars

Table 4: All *Serious* Onshore Gas Transmission & Gathering Pipeline Incidents

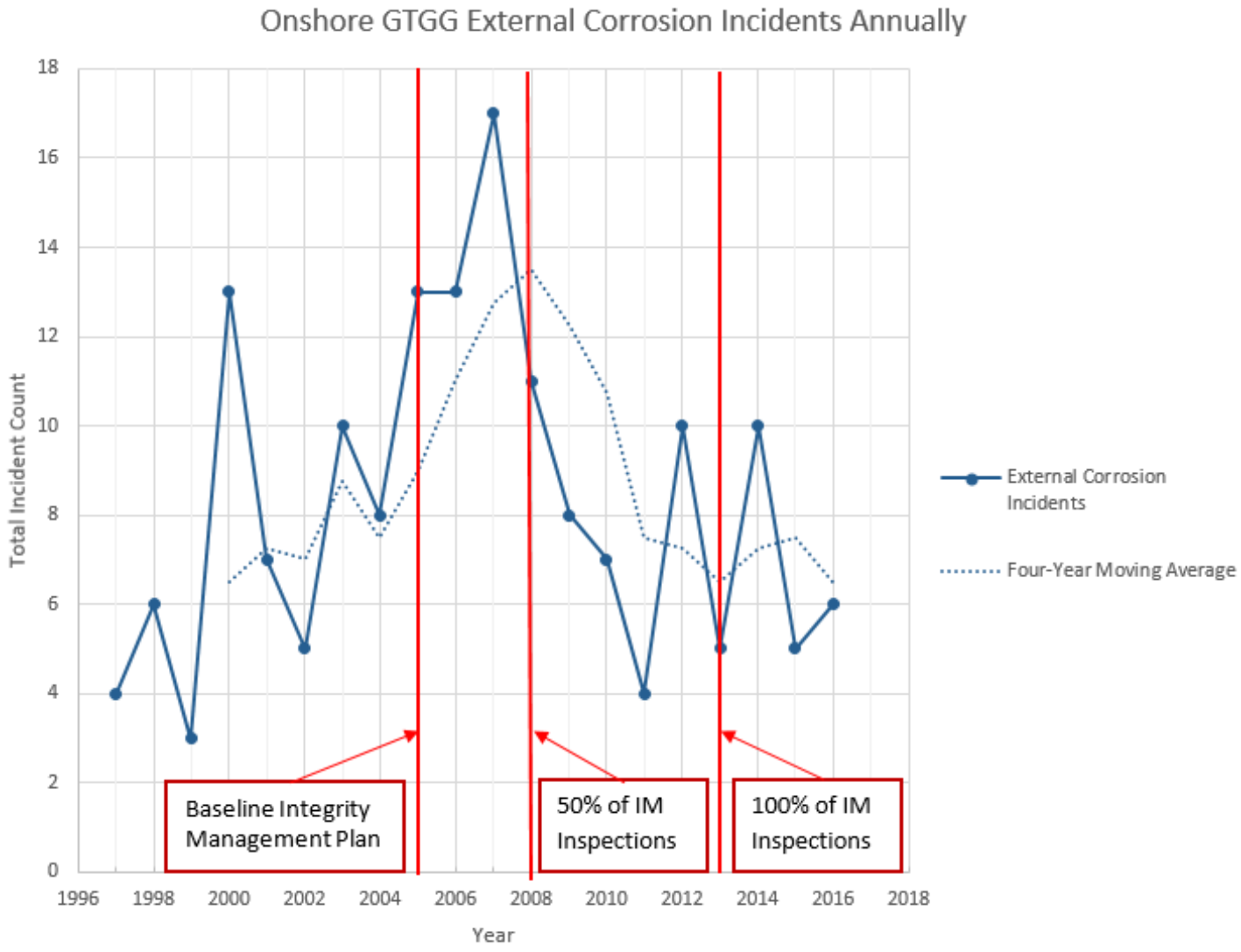
EXTERNAL CORROSION

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	**Total**
Annual Incident Count	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	1	**2**

INTERNAL CORROSION

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	**Total**
Annual Incident Count	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2**

Serious incidents for gas transmission pipelines are those that involve a fatality or injury requiring in-patient hospitalization. While no Serious incident is acceptable, Serious incidents caused by corrosion on an onshore gas pipeline represent less than %% of Serious incidents over the past 20 years.



This chart tracks the count of all external corrosion incidents reported to PHMSA involving onshore gas transmission and gathering pipelines over the past 20 years. The trend demonstrates a decrease in annual reportable incident count during the same period when the Gas Integrity Management Regulations were implemented for High Consequence Areas (HCAs). There have only been four significant incidents on gas transmission pipelines in HCAs attributable to external corrosion since 2004, when the Integrity Management regulations were promulgated. There has only been one significant incident on gas transmission pipelines in HCAs attributable to internal corrosion since 2004. Expanding integrity assessments outside of HCAs, as PHMSA proposes, may have a similar impact in preventing incidents due to external corrosion.

H. Operator Case Study: Internal Corrosion Gas Monitoring Equipment

During the first GPAC meeting, the discussion concerning the current state of gas stream monitoring throughout the national infrastructure as well as the costs to comply with PHMSA's proposed requirements was a point of confusion and concern. The Associations provide the following information to guide future conversations.

The Proposed Requirement

PHMSA proposes to introduce a new requirement within Subpart I for monitoring and mitigating internal corrosion. The proposed requirement prescribes that operators of onshore gas transmission pipelines "develop and implement a monitoring and mitigation program" for internal corrosion. The program must include monitoring at points where *potentially* corrosive contaminants enter the pipeline. PHMSA's use of the term "potentially" is a concern for operators. While today PHMSA may have a loose interpretation of "potentially", individual inspectors, state regulators, or PHMSA may have vastly different interpretations in the future. One such interpretation is that *all* receipt points on a gas transmission system could be *potential* points where corrosive constituents could enter.

In the next section of these comments the Associations offer suggested edits to PHMSA's proposed requirements that mirror the discussion during the GPAC meeting and the concerns identified through these comments.

What are operators currently doing to address the threat of internal corrosion?

Operators currently install filters, separators, dehydrators and drips in their system to remove free liquid and corrosive constituents from their pipeline systems. Additionally, where necessary, operators are installing corrosion probes or taking corrosion coupon samples to verify the absence of internal corrosion in their system. Finally, operators are currently adhering to the existing requirements in §192.477: *Internal corrosion control: monitoring,* that requires operators to determine the effectiveness of internal corrosion mitigation strategies. In April 2007, PHMSA also added new subsection §192.143 and expanded §192.476 to address design and construction standards for managing internal corrosion.

Where Integrity Assessments (ILI, DA, Pressure Tests) have not identified internal corrosion, and pipe inspection reports have not indicated internal corrosion, any prescriptive requirement to install gas monitoring equipment would be an unnecessary diversion of resources from addressing a company's more significant risks.

What does it cost to comply with PHMSA's requirements?

In the proposed requirements of §192.478(b) operators must monitor for "potentially corrosive constituents [that] include but are not limited to: carbon dioxide, hydrogen sulfide, sulfur, microbes, and free water, either by itself or in combination." The Associations believe that in order to meet this requirement, operators may have to install a Gas Chromatograph, a H2O Analyzer, an O2 Analyzer and a H2S Analyzer. Additionally, for operational requirements, safety and security reasons, this equipment is typically housed in a small shed-like equipment building. PHMSA's statements in the PRIA support the Associations' view, particularly the comment that "the proposed rule would require the use of specific gas quality monitoring equipment for HCA segments, including but not limited to, a moisture analyzer, chromatograph, carbon dioxide sampling, and hydrogen sulfide sampling."[19]

[19] PRIA. Page 88.

The table below outlines two transmission operators' estimates for the capital investment cost of this equipment. There will be additional costs associated with the operations and maintenance of the equipment. These costs greatly exceed PHMSA's estimation of $10,000 per location for monitoring equipment costs used in the PRIA.[20] PHMSA estimates that there are 40 receipt points throughout the nation's gas transmission infrastructure that will require the installation of new monitoring equipment. The Association believes it is likely that there are tens of thousands of these points. If PHMSA moves forward with the requirement as proposed, the potential industry-wide cost of this requirement is several billion dollars.

Gas Chromatograph	$85,000
H2O Analyzer	$55,000
O2 Analyzer	$35,000
H2S Analyzer	$75,000
Auxiliary Equipment & Equipment Building	$110,000
Total Equipment Costs per Receipt Point	**$360,000**

Operator Case Studies: Impact of the Proposed Internal Corrosion Gas Quality Monitoring Requirements

Operator Case Study 1
LDC Operator
30 Supply Receipt Points from Local Production & Transmission Pipelines

Supply Source	Current Practice	Additional NPRM Requirements
Local Production	LDC takes a gas sample monthly and monitors for hydrocarbons, CO2, H2S, H2O and BTU content.	Design, construct, and operate gas chromatographs and constituent monitoring at each receipt point.
Interstate Transmission Pipelines	Gas tariff requires the Interstate Transmission Pipeline Company to supply pipeline quality gas. The LDC monitors the supplier's "Gas Quality" postings, which primarily includes the BTU and CO2 content and most do not include H2S and H2O content. **	Design, construct, and operate gas chromatographs and constituent monitoring at each receipt point.
	Current Internal Corrosion Monitoring Costs: $400/ sample on Local Production receipt points	**Total Compliance Cost:** Approximately $10,800,000 + annual operations & maintenance costs

[20] PRIA. Page 91. Table 3-75. It should be noted that the requirement for §192.478 is not limited to gas transmission pipelines in HCA segments, but instead applies to all gas transmission pipelines.

Operator Case Study 2
Gas Transmission Pipeline Operator
290 Supply Receipt Points from Transmission Pipelines & Storage Facilities

Supply Source	Current Practice	Additional NPRM Requirements
Interstate Transmission Pipelines	The following equipment is installed at a subset of the 273 receipt locations: Gas Chromatographs 192 H2O Analyzers 120 O2 Analyzers 105 H2S Analyzers 11 Equipment Buildings 101	Expand the installation of gas chromatographs and constituent monitoring to all receipt points. Gas Chromatographs 81 H2O Analyzers 153 O2 Analyzers 168 H2S Analyzers 262 Equipment Buildings 172
Storage Facilities	The transmission pipeline company has H2S Analyzers installed at 4 of the 17 storage facilities.	Install H2S Analyzers at the remaining 13 storage facilities.
	Current Internal Corrosion Monitoring Costs: Annual Operations & Maintenance Costs on Existing Equipment	**Total Compliance Cost:** Approximately $61,645,000 + annual operations & maintenance costs

I. Redline Code: Suggested Changes to Proposed §192.478

It is the Associations' position that PHMSA's existing regulations provide more than appropriate internal corrosion protection for all transmission pipelines. These regulations prohibit the transportation of corrosive gas unless investigated and addressed before transport (§192.475(a)) and require all operators to investigate and minimize internal corrosion whenever found (§192.475(b)). In addition, existing rules require consideration and avoidance of internal corrosion risks during construction and design of gas pipelines, and during replacements or repairs (§192.476). Pipeline operators have an obvious interest in maintaining the quality of the product transported through their systems. Therefore, the addition of §192.478(b) for all transmission pipelines is unnecessary. At a minimum, the requirements in proposed §192.478 should only apply to non-dry gas systems where liquid water is present.

The corrosion incident data clearly shows that internal corrosion is not a significant cause of serious onshore pipeline incidents, further suggesting that existing rules and industry action are sufficient. If PHMSA believes that additional internal corrosion control requirements are necessary, the Associations suggest the following based on the GPAC discussion, as well as concerns shared by the public or identified through written comments on the Proposed Rule.

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

(a) For **non-dry gas** onshore transmission pipelines, 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**, as necessary**. Potentially corrosive constituents include but are not limited to: carbon dioxide, hydrogen sulfide, sulfur, microbes, and ~~free~~ **liquid** water, either by itself or in combination. Each operator must evaluate the partial pressure of each corrosive constituent**, where applicable,** by itself or in combination to evaluate the effect of the corrosive constituents on the internal corrosion of the pipe**, as necessary,** and implement mitigation measures.

> Operators should evaluate each system transporting non-dry gas, including results of the monitoring program, to determine appropriate mitigation measures. The same mitigations are neither necessary nor appropriate for all situations.

> NACE SP-0106 references "liquid water" instead of "free water."

(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 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;~~

~~(3) Evaluation twice each calendar year, at intervals not to exceed 7-½ 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.~~

(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.~~

> The Associations believe that PHMSA's proposed §192.478(c) is unnecessary as it is exactly duplicative of existing §192.477. PHMSA and the GPAC should determine where this requirement is managed moving forward.

(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.

PHMSA stated during the GPAC meeting its intent to considering adjusting the monitoring interval to once each calendar year (Page 228 of 1/11 Transcript).

VII. CORROSION PREVENTIVE & MITIGATIVE MEASURES

A. Industry Position: Analysis of Duplicative Actions between Subpart I and Proposed §192.935(f)

Current internal corrosion regulations in Subpart I of 49 CFR 192 state that corrosive gas may not be transported unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize the internal corrosion (§192.474). Additional design, construction, and monitoring requirements are set forth in §192.476 and §192.477. The NPRM does not acknowledge that in April 2007, PHMSA added a new subsection (§192.143) requiring that the design and installation of pipeline components and facilities meet applicable requirements for corrosion control in subpart I and expanded §192.476 to address design and construction standards for managing internal corrosion.[21]

Further, the proposed requirements in §192.935(f) are duplicative with the proposed requirements in §192.478 as illustrated in the table below. As such, the Associations suggest that PHMSA strike the duplicative language in §192.935(f) and simply reference the requirements set forth in §192.478 – *see* "Option #1 – Associations Recommendation for 192.935(f)" below. It should also be noted that the requirements proposed in §192.935(f) are nearly identical to those required in the §192.620 (d)(5), which sets forth prescriptive corrosion control requirements for alternative MAOP conditions.

Proposed Subpart I Requirements §192.478	**Proposed Internal Corrosion §192.935(f)**
(a) For onshore transmission pipelines, 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. 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 by itself or in combination to evaluate the effect of the corrosive constituents on the internal corrosion of the pipe and implement mitigation measures.	(f) Internal corrosion. As an operator gains information about internal corrosion, it must enhance its internal corrosion management program, as required under subpart I of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to internal corrosion. At a minimum, as part of this enhancement, operators must—
(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 <u>monitoring equipment to determine the gas stream constituents;</u>	(1) <u>Monitor for, and mitigate the presence of, deleterious gas stream constituents.</u>
(2) Product sampling, inhibitor injections, in-line cleaning pigging, separators or other technology to mitigate the potentially corrosive gas stream constituents;	(2) At points where gas with potentially deleterious contaminants enters the pipeline, <u>use filter separators or separators and continuous gas quality monitoring equipment.</u>

[21] Pipeline Safety: Design and Construction Standards to Reduce Internal Corrosion in Gas Transmission Pipelines, 72 Fed. Reg. 20,055, 20,059 (Apr. 23, 2007).

Proposed Subpart I Requirements §192.478	Proposed Internal Corrosion §192.935(f)
(3) Evaluation twice each calendar year, at intervals not to exceed 7-½ 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	(3) At least once per quarter, use gas quality monitoring equipment that includes, but is not limited to, a moisture analyzer, chromatograph, carbon dioxide sampling, and hydrogen sulfide sampling.
(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 months.	(4) Use <u>cleaning pigs</u> and sample accumulated liquids and solids, including tests for microbiologically induced corrosion. (5) <u>Use inhibitors</u> when corrosive gas or corrosive liquids are present.
(d) Each operator must review its monitoring and mitigation program at least twice each calendar year, at intervals not to exceed 7 ½ months, based on the results of its gas stream sampling and internal corrosion monitoring in (a) and (b) and implement adjustments in its monitoring <u>for and mitigation of the potential for internal corrosion due to the presence of potentially corrosive gas stream constituents.</u>	(6) Address potentially corrosive gas stream constituents as specified in § 192.478(a), where the volumes exceed these amounts over a 24-hour interval in the pipeline as follows: i. Limit carbon dioxide to three percent by volume; ii. Allow no free water and otherwise limit water to seven pounds per million cubic feet of gas; and iii. Limit hydrogen sulfide to 1.0 grain per hundred cubic feet (16 ppm) of gas. If the hydrogen sulfide concentration is greater than 0.5 grain per hundred cubic feet (8 ppm) of gas, implement a pigging and inhibitor injection program to address deleterious gas stream constituents, including follow-up sampling and quality testing of liquids at receipt points (7) Review the program at least semi-annually based on the gas stream experience <u>and implement adjustments to monitor for, and mitigate the presence of, deleterious gas stream constituents.</u>

* In this table, underlined <u>text</u> is for emphasis of duplicative requirements.

B. Option #1 - Associations Recommendation: Reference §192.478 in §192.935(f)

The Associations provide the following suggested language for §192.935(f). Due to the broadened requirements in §192.478 for all transmission pipelines, the Preventive & Mitigative (P&M) measures required within §192.935 for transmission pipelines in HCAs are duplicative and unnecessary. The Associations recommend that PHMSA simply reference §192.478 so as to eliminate duplication and uncertainty that may arise with two similar requirements in different sections of the pipeline safety regulations.

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

(f) *Internal corrosion*. As an operator gains information about internal corrosion, it must ~~enhance~~ **evaluate** its internal corrosion management program, as required under subpart I of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to internal corrosion. At a minimum, as part of this ~~enhancement~~ **evaluation,** operators must **apply the requirements set forth in §192.478.**

C. Option #2 - Redline Code: Suggested Changes to Proposed §192.935(f)

If PHMSA believes there is clarity in duplicating the requirements from Subpart I within the P&M requirements of Subpart O, the Associations recommend the following modifications to PHMSA's proposed requirements for §192.935(f). These modifications represent the discussion that occurred at the January GPAC meeting, as well as concerns shared by the public or identified through written comments on the Proposed Rule.

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

(f) *Internal corrosion*. As an operator gains information about internal corrosion, it must ~~enhance~~ **evaluate** its internal corrosion management program, as required under subpart I of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to internal corrosion. At a minimum, as part of this ~~enhancement~~ **evaluation,** operators must **consider, based on a risk analysis for the pipeline segment, implementing the following, as necessary:**

(1) Monitor for, and mitigate the presence of, deleterious gas stream constituents.
(2) At points where gas with potentially deleterious contaminants enters the pipeline, use filter separators or separators ~~and~~ or continuous gas quality monitoring equipment**, or take other appropriate steps to mitigate the risk associated with deleterious contaminants.**
(3) At least once per quarter, use gas quality monitoring equipment that **may** include~~s, but is not limited to,~~ a moisture analyzer, chromatograph, carbon dioxide sampling, ~~and~~ **or** hydrogen sulfide sampling.
(4) Use cleaning pigs and sample accumulated liquids and solids, including tests for microbiologically induced corrosion.
(5) Use inhibitors when corrosive gas or corrosive liquids are present.

> There was clear agreement from the GPAC that P&M measures should be tied to the results of a risk analysis (Page 43 of 1/12 Transcript)

> Operators should be able to utilize all available tools for mitigating the risk associated with internal corrosion identified through their risk assessment.

(6) ~~Address potentially corrosive gas stream constituents as specified in § 192.478(a), where the volumes exceed these amounts over a 24-hour interval in the pipeline as follows:~~

The other constituents are benign if there is no liquid water present, regardless of concentration.

(i) ~~Limit carbon dioxide to three percent by volume;~~

(ii) ~~Allow no free water and otherwise limit water to seven pounds per million cubic feet of gas; and~~

(iii) ~~Limit hydrogen sulfide to 1.0 grain per hundred cubic feet (16 ppm) of gas. If the hydrogen sulfide concentration is greater than 0.5 grain per hundred cubic feet (8 ppm) of gas, implement a pigging and inhibitor injection program to address deleterious gas stream constituents, including follow-up sampling and quality testing of liquids at receipt points.~~

(7) Review the program at least semi-annually based on the gas stream experience and implement adjustments to monitor for, and mitigate the presence of, deleterious gas stream constituents.

D. Industry Position: Analysis of Duplicative Actions between Subpart I and Proposed §192.935(g)

PHMSA's proposed external corrosion requirements (§192.935 (g)) would require operators to perform cathodic protection (CP) and close interval surveys (CIS) for pipe segments located in HCAs at least every seven years. In addition, if annual test station inspections reflect insufficient CP levels, an operator would also be required to perform remediation within six months and perform a close interval survey on both sides of the affected test station to confirm that adequate corrosion control has been restored. Under proposed §192.935(g) CIS must be performed with the CP current interrupted.

The Proposed Rule acknowledges that existing corrosion control requirements **<u>are effective</u>** in reducing incidents caused by external corrosion. However, PHMSA expressed concern that its regulations are too general and do not address issues "that experience has shown are important to protecting pipelines from corrosion damage." *NPRM at 20781 and 20782.* Relying on "lessons learned" from certain incidents and the improved capabilities of corrosion evaluation tools and methods, PHMSA asserts that "more specific minimum requirements are needed [to] control" external corrosion.

Based on the above considerations and the discussion that occurred at the January GPAC Meeting, the Associations recommend changes to the proposed language for §192.935(g) – *see* "Redlined Code – Suggested Changes to §192.935(g)" below.

The Associations would also like to outline the duplication that occurs between Subpart I for all gas transmission pipelines and the P&M requirements for gas transmission pipelines operating in HCAs. This duplication is outlined for the benefit of PHMSA and the GPAC in the table below. Similar to the requirements for internal corrosion prevention, PHMSA uses the requirements set forth in §192.620(d)(6)-(8) designed for alternative MAOP conditions to establish "more specific minimum requirements" for external corrosion control. There is no technical justification for applying requirements for alternate MAOP conditions broadly to the transmission P&M criteria.

Proposed External Corrosion control: Interference Currents - §192.473	**Proposed External Corrosion P&M Measures §192.935(g)**
(a) Each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize the detrimental effects of such currents. (b) Each impressed current type cathodic protection system or galvanic anode system must be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures.	(g) External corrosion. As an operator gains information about external corrosion, it must enhance its external corrosion management program, as required under subpart I of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to external corrosion. At a minimum, as part of this enhancement, operators must—

(c) For onshore gas transmission pipelines, the program required by paragraph (a) must include: (1) Interference surveys for a pipeline system to detect the presence and level of any electrical stray current. Interference surveys must be taken on a 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; (2) Analysis of the results of the survey to determine the cause of the interference and whether the level could impact the effectiveness of cathodic protection; and (3) 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.	(1) Control electrical interference currents that can adversely affect cathodic protection as follows: (i) As frequently as needed (such as when new or uprated high voltage alternating current power lines greater than or equal to 69 kVA or electrical substations are co-located near the pipeline), but not to exceed every seven years, perform the following: (A) Conduct an interference survey (at times when voltages are at the highest values for a time period of at least 24-hours) to detect the presence and level of any electrical current that could impact external corrosion where interference is suspected; (B) Analyze the results of the survey to identify locations where interference currents are greater than or equal to 20 Amps per meter squared; and (C) Take any remedial action needed within six months after completing the survey to protect the pipeline segment from deleterious current. Remedial action means the implementation of measures including, but not limited to, grounding along the pipeline to reduce interference currents. Any location with interference currents greater than 50 Amps per meter squared must be remediated. If any AC interference between 20 and 50 Amps per meter squared is not remediated, the operator must provide and document an engineering justification.

Proposed §192.319, §192.461, §192.465	Proposed External Corrosion P&M Measures §192.935(g)
§192.319 (d) Promptly after a ditch for a steel onshore transmission line is backfilled, but not later than three 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). 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. Each operator of transmission pipelines must make and retain for the life of the pipeline records documenting the coating assessment findings and repairs. *§192.461* (f) Promptly, but no later than three 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). 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. *§192.465* (f) For onshore transmission lines, where any annual test station reading (pipe-to-soil potential measurement) indicates cathodic	(2) Confirm the adequacy of external corrosion control through indirect assessment as follows: (i) Periodically (as frequently as needed but at intervals not to exceed seven years) assess the adequacy of the cathodic protection through an indirect method such as close-interval survey, and the integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG). (ii) Remediate any damaged coating with a voltage drop classified as moderate or severe (IR drop greater than 35% for DCVG or 50 dBµv for ACVG) under section 4 of NACE RP0502–2008 (incorporated by reference, see § 192.7). (iii) Integrate the results of the indirect assessment required under paragraph (g)(2)(i) of this section with the results of the most recent integrity assessment required by this subpart and promptly take any needed remedial actions no later than 6 months after assessment finding. (iv) Perform periodic assessments as follows: (A) Conduct periodic close interval surveys with current interrupted to

Proposed §192.319, §192.461, §192.465	Proposed External Corrosion P&M Measures §192.935(g)
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.	confirm voltage drops in association with integrity assessments under sections §§ 192.921 and 192.937 of this subpart. (B) Locate pipe-to-soil test stations at half-mile intervals within each covered segment, ensuring at least one station is within each high consequence area, if practicable. (C) Integrate the results with those of the baseline and periodic assessments for integrity done under sections §§ 192.921 and 192.937 of this subpart.
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 must confirm restoration of adequate cathodic protection by close interval survey over the entire area.	(3) Control external corrosion through cathodic protection as follows: (i) If an annual test station reading indicates cathodic protection below the level of protection required in subpart I of this part, complete assessment and remedial action, as required in § 192.465(f), within 6 months of the failed reading or notify each PHMSA pipeline safety regional office where the pipeline is in service and demonstrate that the integrity of the pipeline is not compromised if the repair takes longer than 6 months. An operator must also notify 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; and (ii) Remediate insufficient cathodic protection levels or areas where protective current is found to be leaving the pipeline in accordance with paragraph (i) above, including use of indirect assessments or direct examination of the coating in areas of low CP readings unless the reason for

Proposed §192.319, §192.461, §192.465	Proposed External Corrosion P&M Measures §192.935(g)
	the failed reading is determined to be a short to an adjacent foreign structure, rectifier connection or power input problem that can be remediated and restoration of adequate cathodic protection can be verified. The operator must confirm restoration of adequate corrosion control by a close interval survey on both sides of the affected test stations to the adjacent test stations.

E. Redline Code: Suggested Changes to Proposed §192.935(g)

The Associations recommend the following modifications to PHMSA's proposed requirements for §192.935(g). These modifications represent the discussion that occurred at the January GPAC meeting, as well as concerns shared by the public or identified through written comments on the Proposed Rule.

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

(g) *External corrosion*. As an operator gains information about external corrosion, it must ~~enhance~~ **evaluate** its external corrosion management program, as required under subpart I of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to external corrosion. At a minimum, as part of this ~~enhancement~~ **evaluation,** operators must **consider, based on a risk analysis for the pipeline segment, implementing the following, as appropriate:**

> There was clear agreement from the GPAC that P&M measures should be tied to the results of a risk analysis (Page 43 of 1/12 Transcript)

(1) Control electrical interference currents that can adversely affect cathodic protection as follows:

(i) As frequently as needed (such as when a new or uprated high voltage alternating current power lines greater than or equal to 69 kVA or electrical substations are co-located near the pipeline), but not to exceed every seven years, perform the following:

(A) Conduct an interference survey (at times when voltages are at the highest values for a time period of at least 24-hours) to detect the presence and level of any electrical current that could impact external corrosion where interference is suspected;

(B) Analyze the results of the survey to identify locations where interference currents are greater than or equal to 20 Amps per meter squared; and

(C) Take any remedial action needed within ~~six months~~ **one year** after completing the survey to protect the pipeline segment from deleterious current. **If permits are necessary, remedial action must be completed promptly following receipt of necessary permits.** Remedial action means the implementation of measures including, but not limited to, additional grounding along the pipeline to reduce interference currents. Any location with interference currents greater than **100** ~~50~~ Amps per meter squared must be remediated. If any AC interference between 20 and ~~50~~ **100** Amps per meter

> As previously discussed with §192.473, the Associations agree with public commenters at the first GPAC meeting that six months is an inadequate timeframe for operators to perform remedial actions in all cases. See the Operator Case Study provided in these comments that outlines the process and timeline that may be required to complete interference current remediation.

> Per NACE SP0177-2014, SS 6.2.1.4.5. "Under certain circumstances, when well coated pipelines are installed in close proximity to HVAC power lines, electromagnetically induced AC can cause external corrosion. AC densities in excess of 30 A/m^2 (2.8 A/ft^2) can be sufficient to cause significant external corrosion of ferrous metals, and at AC densities greater than 100 A/m^2 (9.3 A/ft^2), AC corrosion is to be expected even if a CP criterion is satisfied." The Associations support PHMSA aligning pipeline safety regulations with accepted NACE standards.

squared is not remediated, the operator must provide and document an engineering justification.

(2) Confirm the adequacy of external corrosion control through indirect assessment as follows:

(i) ~~Periodically (as~~ **As** frequently as needed but at intervals not to exceed seven years~~)~~, assess the adequacy of the cathodic protection through an indirect method such as close-interval survey~~, and the integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG).~~ **Alternatively, an operator may validate the effectiveness of the cathodic protection system by demonstrating that corrosion growth is not occurring on the pipeline. This may be accomplished with methods such as ILI run-to-run comparisons or ECDA.**

(ii) Remediate any ~~damaged coating with a voltage drop classified as moderate or severe (IR drop greater than 35% for DCVG or 50 dBμv for ACVG) under section 4 of NACE RP0502–2008 (incorporated by reference, see § 192.7)~~ **cathodic protection levels below the required levels in Appendix D of this part according to § 192.564(d).**

> If the cathodic protection is proven to be effective, the pipeline system is protected from external corrosion.

(iii) Integrate the results of the indirect assessment required under paragraph (g)(2)(i) of this section with the results of the most recent integrity assessment required by this subpart and promptly take any needed remedial actions no later than ~~6 months~~ **15 months** after assessment finding. **If permits are necessary, remedial action must be completed promptly following receipt of necessary permits.**

> The Associations encourage PHMSA to mirror remediation timeframes outlined in §192.465. As previously mentioned, PHMSA has historically interpreted the requirement to remediate CP deficiencies "promptly" to mean 'before the next test interval.' If PHMSA does add a mandatory CIS requirement for any annual CP test data deficiency, PHMSA should provide operators with 15 months to complete the associated remediation, because existing regulation allows annual CP tests to be conducted 'no later than 15 months apart.'

(iv) Perform periodic assessments as follows:

(A) Conduct periodic close interval surveys ~~with current interrupted~~ **to confirm compliance with Appendix D criteria** to confirm voltage drops in association with integrity assessments under sections §§ 192.921 and 192.937 of this subpart.

> Appendix D outlines long-standing practices for conducting CIS

(B) Locate pipe-to-soil test stations at half-mile intervals within each covered segment, ensuring at least one station is within each high consequence area, if practicable.

(C) Integrate the results with those of the baseline and periodic assessments for integrity done under sections §§ 192.921 and 192.937 of this subpart.

F. Redline Code: Suggested Changes to Appendix D

The Associations recommend the following modifications to PHMSA's proposed requirements for Appendix D. These modifications represent the discussion that occurred at the January GPAC meeting, as well as concerns shared by the public or identified through written comments on the Proposed Rule.

Appendix D to Part 192 – Criteria for Cathodic Protection and Determination Measurements

I. Criteria for cathodic protection—

A. Steel, cast iron, and ductile iron structures

(1) **Cathodic protection must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in Section 6 of NACE SP 0169.**

(2) A negative (cathodic) voltage across the structure electrolyte boundary of at least 0.85 volt, with reference to a saturated copper-copper sulfate reference electrode, often referred to as a half cell. Determination of this voltage must be made in accordance with sections II and IV of this appendix.

(3) A minimum negative (cathodic) polarization voltage shift of at least 100 millivolts. This polarization voltage shift ~~must~~ **should** be determined in accordance with sections II and IV of this appendix.

PHMSA explicitly stated that gas distribution pipelines were not addressed by this proposed rulemaking. Therefore, PHMSA should clarify that the modified version of Appendix D only applies to gas transmission pipelines. PHMSA may need to provide for two versions of Appendix D until they address Appendix D for gas distribution pipelines in a separate rulemaking.

Gas Distribution pipeline operators can support the modifications to Appendix D, if PHMSA fully incorporates Section 6 of NACE SP0169.

B. Aluminum structures

(1) Except as provided in paragraphs (2) and (3) of this paragraph, a minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

(2) Notwithstanding the alternative minimum criteria in paragraph (1), if aluminum is catholically protected at voltages in excess of 1.20 volts as measured with reference to a copper-copper sulfate reference electrode in accordance with section II of this appendix, the aluminum may suffer corrosion resulting from the build-up of alkali on the metal surface. A voltage in excess of 1.20 volts may not be used unless previous test results indicate no appreciable corrosion will occur in the particular environment.

(3) Since aluminum may suffer from corrosion under high pH conditions, and since application of cathodic protection tends to increase the pH at the metal surface, careful investigation or testing must be made before applying cathodic protection to stop pitting attack on aluminum structures in environments with a natural pH in excess of 8.

C. Copper structures. A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

D. *Metals of different anodic potentials.* A negative (cathodic) voltage, measured in accordance with section IV of this appendix, equal to that required for the most anodic metal in the system must be maintained. If amphoteric structures are involved that could be damaged by high alkalinity covered by paragraphs (2) and (3) of paragraph B of this section, they must be

electrically isolated with insulating flanges, or the equivalent.

II. *Interpretation of voltage measurement.* Structure-to-electrolyte potential measurements must be made utilizing measurement techniques that will minimize voltage (IR) drops other than those across the structure-electrolyte boundary. All voltage (IR) drops other than those across the structure electrolyte boundary will be differentiated, such that the resulting measurement accurately reflects the structure-to-electrolyte potential.

It is unclear how PHMSA's use of "minimizing IR drops" and "differentiating IR drops" are different than the previous language "considering" IR drops. PHMSA should consider retaining the existing language, or reference Section 6 of NACE SP 0169 in lieu of this Section.

III. *Determination of polarization voltage shift.* The polarization voltage shift ~~must~~ **can** be determined **by methods identified in NACE SP0207-2007, Section 5, such as** interrupting the protective current and measuring the polarization decay. **On systems where the current can be interrupted,** when the current is initially interrupted, an immediate voltage shift occurs **which is** often referred to as **IR drop.** The voltage reading after the immediate shift must be used as the base reading from which to measure polarization decay in paragraphs A(2), B(1), and C of section I of this appendix.

During the GPAC, the importance of aligning Appendix D with NACE standards was discussed. Adding this language would also align with Part 195. (Page 224 and 295 of 1/11 Transcript).

IV. *Reference electrodes (half cells).*

A. Except as provided in paragraphs B and C of this section, negative (cathodic) voltage must be measured between the structure surface and a saturated copper- copper sulfate reference electrode contacting the electrolyte.

B. Other standard reference electrodes may be substituted for the saturated cooper-copper sulfate electrode. Two commonly used reference electrodes are listed below along with their voltage equivalent to −0.85 volt as referred to a saturated copper-copper sulfate reference electrode:

(1) Saturated KCl calomel half cell: −0.78 volt.

(2) Silver-silver chloride reference electrode used in sea water: −0.80 volt.

C. In addition to the standard reference electrodes, an alternate metallic material or structure may be used in place of the saturated copper-copper sulfate reference electrode if its potential stability is assured and if its voltage equivalent referred to a s aturated copper-copper sulfate reference e lectrode is established

VIII. INTEGRITY MANAGEMENT CLARIFICATIONS

A. Comparison: §192.917(b)(1) and ASME B31.8S

In the Preliminary Regulatory Impact Analysis (PRIA) for the Proposed Rule and as reiterated during the January GPAC Meeting, PHMSA agrees the pipeline attributes listed in §192.917(b)(1) "area already required by reference to ASME B31.8S, Sections 4 and 5, as if they were set out in the rule in full (See §192.7(a)). Therefore, this requirement would not impose an additional cost burden on pipeline operators."[22] ASME B31.8S Section 4.2.1: Prescriptive Integrity Management Programs, states:

> *Limited data sets shall be gathered to evaluate each threat for prescriptive integrity management program applications. These data lists are provided in Nonmandatory Appendix A for each threat and summarized in Table 4.2.1-1. All of the specified data elements shall be available for each threat in order to perform the risk assessment. If such data are not available, it shall be assumed that the particular threat applies to the pipeline segment being evaluated.*

Therefore, the Associations utilized the "data sets" and "performance" measures within Appendix A for each of the nine threats to develop the Table below. Each data set that cannot be reasonably implied from those listed in ASME B31.8S have been highlighted in red. The Associations ask the GPAC to recommend that PHMSA limit the required pipeline attributes in §192.917(b)(1) to those that can be directly linked to those listed in ASME B31.8S.

Pipeline Attributes & Other Relevant Information §192.917(b)(1)	**ASME B31.8S Appendix A (*Nonmandatory*)**
Pipe Diameter	A-1,2,9
Wall Thickness	A-1,2,9
Seam Type	A-4
Joint Factor	A-4
Manufacturer	
Manufacturing Date	A-4
Manufacturing Data & Records	A-4[23]
Grade (i.e. Pipe Material)	A-4,5,9
Hardness	
Toughness	
Hard Spots	
Chemical Composition	
Equipment Properties	A-6[24]
Year of Installation	A-1,2,4,9
Bending Method	A-5
Joining Method	A-5,9
Joining Process & Inspection Results	A-5
Depth of Cover Surveys	A-5[25]

[22] PRIA. Section 3.2.2 Assessment of Regulatory Impact. Page 71.
[23] A-4.2 (c): manufacturing process (age of manufacture as alternative)
[24] A-6.2 Includes 8 data sets that may be summarized as "Equipment Properties"
[25] A-5.2(k): soil properties and depth of cover for wrinkle bends

Depth of Cover: Stream Crossings	
Depth of Cover: Beach Approaches	
Crossings: Foreign Lines	
Crossings: High Voltage Power Lines	
Crossings: Location of Casings	
Pressure Test: Pressure	A-1,2,3,5
Pressure Test: Leaks & Failures	A-4[26]
Pressure Test: Leaks & Failure Causes	
Pressure Test: Leaks & Failure Repairs	
Pipe Coating Type	A-1,3
Pipe Coating Application Method or Process	
Pipe Coating Inspection Reports	
Pipe Coating Condition	A-1
Pipe Coating Repairs	
Soil / Backfill Type	A-1,2,9
Construction Inspection Reports: General	
Construction Inspection Reports: Girth weld non-destructive examinations	A-5
Construction Inspection Reports: Post backfill coating surveys	
Construction Inspection Reports: Pipe coating inspection reports	
Cathodic Protection: Type	
Cathodic Protection: Location	
Cathodic Protection: System Performance	A-1
Gas Quality	A-2
Flow Rate	A-2
Normal maximum operating pressure	A-2
Normal minimum operating pressure	A-2
Maximum Allowable Operating Pressure (MAOP)	A-2
Class Location	
Leak & Failure History: In-Service Ruptures or Leaks	A-1,2,7
Leak & Failure History: Abnormal Operations	
Leak & Failure History: Safety Related Conditions – Reported	
Leak & Failure History: Safety Related Conditions – Unreported	
Leak & Failure History: Investigation Reports	
Leak & Failure History: Leak & Failure Causes & Consequences	A-1,2,5,6
Pipe Wall Temperature	A-3,5
Pipe O&M Inspection Reports: Integrity Assessment Data (ILI)	A-1,2,7
Pipe O&M Inspection Reports: Integrity Assessment Data (Pressure Tests)	A-1,2
Pipe O&M Inspection Reports: Integrity Assessment Data (DA)	A-1,2
Pipe O&M Inspection Reports: Integrity Assessment Data (GWUT)	
Pipe O&M Inspection Reports: Integrity Assessment Data (Other Methods)	
Pipe O&M Inspection Reports: Close Interval Survey Results	
Pipe O&M Inspection Reports: Electrical Survey Results	
Pipe O&M Inspection Reports: CP Rectifier Readings	
Pipe O&M Inspection Reports: AC/DC Interference Surveys	

[26] A-4.8(a): number of hydrostatic test failures caused by manufacturing defects

Pipe O&M Inspection Reports: Foreign Structure Interference Surveys	
Pipe O&M Inspection Reports: Pipe Coating Surveys	
Pipe O&M Inspection Reports: Pipe Condition Reports	A-1,2,5,7
Pipe O&M Inspection Reports: Non-Destructive Examinations	
Pipe O&M Inspection Reports: Stress Corrosion Cracking Excavation Findings	
Pipe O&M Inspection Reports: Selective Seam Weld Corrosion Excavations & Findings	
Pipe O&M Inspection Reports: Gas Stream Sampling Reports	A-2
Pipe O&M Inspection Reports: Internal Corrosion Monitoring Results	A-2
Pipe O&M Inspection Reports: Cleaning Pig Sampling Results	A-2[27]
Outer Diameter / Inner Diameter Corrosion Monitoring	A-2[28]
Operating Pressure History	A-2,4,5
Operating Pressure Fluctuations	A-2,5
MAOP Exceedances	A-6
Over-Pressure-Protection Performance Records	A-6
Encroachments	A-7
One-Call Data	A-7
Pipe Exposures: Encroachments	A-7
Pipe Exposures: Natural Forces	A-5,7,9
Pipe Damage Repairs	A-7
Vandalism	A-7
External Forces	A-5,9
Audits & Reviews	A-8
Industry experience for incident, leak & failure history	
Aerial Photography	
Other pertinent information	

Legend for Table X

A-1	External Corrosion Threat
A-2	Internal Corrosion Threat
A-3	Stress Corrosion Cracking Threat
A-4	Manufacturing Threat
A-5	Construction Threat
A-6	Equipment Threat
A-7	Third-Party Damage Threat
A-8	Incorrect Operations Threat
A-9	Weather-Related and Outside Force Threat

[27] A-2.2 (g): gas, liquid, or solid analysis (particularly hydrogen sulfide, carbon dioxide, oxygen, free water, and chlorides)

[28] A-2.2 (i): corrosion detection devices (coupons, probes, etc.)

B. Redline Code: Suggested Changes to the Proposed §192.917(a)-(c)

The Associations provide the following suggested modifications to PHMSA's proposed §192.917(c). These modifications represent the discussion that occurred at the January GPAC meeting, as well as concerns shared by the public or identified through written comments 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 existing data and information on the entire pipeline that could be relevant to the covered segment. 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 all data elements specified in this section starting [*insert date 1 year after effective date of the final rule*], with all available attributes integrated by [*insert date 3 years after publication of rule.*]** ~~At a minimum~~**,** An operator must ~~gather and evaluate~~ **consider** 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 **available** 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;

Without defining "verify" and "validate" or justifying the addition of these terms, PHMSA should remove them from the Final Rule language.

PHMSA should provide operators with additional time to consider, gather, and integrate data sets beyond those listed in ASME B31.8S. The Associations suggest language consistent with the Safety of Hazardous Liquid Pipelines Rule.

The regulatory text should recognize that operators may not have all the listed pipeline attributes available for integration into their TIMP Risk Models. The Associations recommend the addition of a new §192.917(b)(2) that mirrors language from ASME B31.8S to address attributes that are unavailable.

The "material properties" in (iii) should not overlap with (i) and be consistent with ASME/ANSI B31.8S

(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;**~~

Depth of cover surveys should be removed to stay consistent with ASME/ANSI B31.8S.

(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;**~~

(B) Post backfill coating surveys;

(C) Coating inspection ("jeeping") reports;

"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.

(xiv) Cathodic protection installed, including but not limited to type and location;

(xv) Coating type;

(xvi) Gas quality;

(xvii) Flow rate;

(xviii) Normal maximum and minimum operating pressures, including maximum allowable operating pressure (MAOP);

(xix) Class location;

(xx) Leak and failure history including any in-service ruptures or leaks from incident reports, abnormal operations, safety related conditions (both reported and unreported) and failure investigations required by § 192.617, and their identified causes and consequences;

(xxi) Coating condition;

(xxii) CP system performance;

(xxiii) Pipe wall temperature;

(xxiv) 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;

(xxv) Outer Diameter/Inner Diameter corrosion monitoring;

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

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

(xxviii) ~~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;~~

"Encroachments" should be removed to stay consistent with ASME/ANSI B31.8S.

(xxix) Repairs;

(xxx) Vandalism;

(xxxi) External forces;

(xxxii) Audits and reviews;

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

(xxxiv) Aerial photography;

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

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

The Associations recommend that PHMSA remove the "other pertinent information" as the requirement for 192.917(b)(1) already states "including, but not limited to:".

(2) **If the operator does not have a pipeline attributes listed in paragraph (b)(1) of this section available, sound engineering assumptions may be used.**

PHMSA should include language representative of language from ASME B31.8S Appendix A Section A-1.2 in a new §192.917(b)(2). This is a practice that operators have been adhering to since its incorporate by reference in 2003. This language allows operators to use sound, engineering assumptions should a data set from §192.917(b)(1) is unavailable.

(3) 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 **adequate control** measures to **ensure consistency and**

Operators already use the best available data for their risk models. Introducing new terms (objective, traceable, verified) adds confusion and appears to add requirements.

The Associations recommend that PHMSA modify the language in §192.917(b)(3) for adequate control measures to match that which was recommended by the GPAC. (See 1/12/17 Transcript. Page 106. Line 5.) This modification results in the second sentence of the proposed 192.917(b)(3) being duplicative. Additionally, the Associations believe the requirement to document SME names & information is too far reaching and could ultimately be interpreted to include all employees that may indirectly interface with the pipeline.

accuracy of information ~~adequately correct any bias in SME input~~. ~~Bias control measures may include training of SMEs and 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.~~

(4) 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

> The inclusion of this requirement would codify the requirement for GIS for all covered segment transmission pipeline operators. Without properly accounting for the burden & cost associated with this requirement, it should not be included in the Final Rule. PHMSA indicated during the GPAC meeting that its intent was not to require GIS (See 1/12 Transcript, Page 121, Line 12.)

(5) 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 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 (§ 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:

> The Associations believe that the requirement to address interacting threats is adequately addressed in 192.917(c)(2). Therefore, the Associations recommend that PHMSA remove this sentence. Additionally, there is no published & accepted definition for "interacting threats". PHMSA should avoid requiring actions for terms that are undefined.

> The Associations ask PHMSA not to use the term "probability" as it has many definitions in this context. Including this term could imply a requirement for Probabilistic Risk Models.

> PHMSA should provide operators with additional time to expand the capabilities and functionality of Risk Models. Specifically, these requirements should be reviewed after the publication of Guidance from the PHMSA Risk Model Work Group.

(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~~;

Industry experts, including those that have attended PHMSA's Risk Modeling Work Group Meetings, have advised against attempting to model "worst case scenarios." Section 192.917(c) creates the obligation to consider consequences, including low-likelihood, high-consequence events.

(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;

PHMSA should remove references to "risk factors" to ensure clarity.

(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.

C. Redline Code: Suggested Changes to the Proposed §192.935(a)

The Associations provide the following suggested modifications to PHMSA's proposed §192.935(a). These modifications represent the discussion that occurred at the January GPAC meeting, as well as concerns shared by the public or identified through written comments 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~~ **Preventive and mitigative measures that operators ~~must~~ may consider** 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.

> PHMSA stated that it was not its intent to require operators perform each of the P&M Measures listed under §192.935(a). (See GPAC Transcript from 1/12/2017. Page 90. Line 21.)

D. Industry Comment: Record Requirements per Proposed Appendix A

PHMSA only included one recordkeeping requirement in Appendix A for Subpart O—Gas Transmission Pipeline Integrity Management, "Records that demonstrate compliance with all of the requirements of subpart O," as required under § 192.947. PHMSA's description fails to recognize that § 192.947 details the minimum records that an operator must maintain. Other provisions in Subpart O could give rise to potential record requirements based on PHMSA's interpretation of § 192.947. By way of contrast, PHMSA included both the general recordkeeping obligation, and the specific regulatory requirement subject to that obligation, in other portions of Appendix A. For example, in Subpart I—Requirements for Corrosion Control, PHMSA included the general recordkeeping requirement of § 192.491, as well as the specific provisions in Subpart I that are subject to that recordkeeping requirement. PHMSA should take the same approach in delineating the IM program recordkeeping requirements in Appendix A to avoid confusion and promote consistency.

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

Terry Boss, *Senior Vice President of Environment, Safety and Operations*
Interstate Natural Gas Association of America
20 F Street, NW
Suite 450
Washington, DC 20001
(202) 216-5900
tboss@ingaa.org

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