DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Part 192

[Docket No. PHMSA–2011–0023; Amdt. No. 192–132]

RIN 2137–AF39

Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), Department of Transportation (DOT).

ACTION: Final rule.

SUMMARY: PHMSA is revising the Federal Pipeline Safety Regulations to improve the safety of onshore gas transmission pipelines. This final rule addresses several lessons learned following the Pacific Gas and Electric Company incident that occurred in San Bruno, CA, on September 9, 2010, and responds to public input received as part of the rulemaking process. The amendments in this final rule clarify certain integrity management provisions, codify a management of change process, update and bolster gas transmission pipeline corrosion control requirements, require operators to inspect pipelines following extreme weather events, strengthen integrity management assessment requirements, adjust the repair criteria for high-consequence areas, create new repair criteria for non-high consequence areas, and revise or create specific definitions related to the above amendments.

DATES: The final rule is effective May 24, 2023. The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of May 24, 2023. The incorporation by reference of other publications listed in this rule was approved by the Director of the Federal Register on July 1, 2020.

FOR FURTHER INFORMATION CONTACT: Technical questions: Steve Nanney, Senior Technical Advisor, by telephone at 713–272–2855. General information: Robert Jagger, Senior Transportation Specialist, by telephone at 202–366–4361.

SUPPLEMENTARY INFORMATION:

I. Executive Summary

A. Purpose of the Regulatory Action

This final rule concludes a decade-long effort by PHMSA to amend its regulations governing onshore natural gas transmission pipelines in response to the tragic September 9, 2010, incident at a Pacific Gas and Electric Company (PG&E) gas transmission pipeline in San Bruno, CA, which resulted in the death of 8 people, injuries to more than 60 other people, and the destruction or damage of over 100 homes. PHMSA expects the new requirements in this final rule will reduce the frequency and consequences of failures and incidents from onshore natural gas transmission pipelines through earlier detection of threats to pipeline integrity, including those from corrosion or following extreme weather events. The safety enhancements in this final rule, therefore, are expected to improve public safety, reduce threats to the environment (including, but not limited to, reduction of greenhouse gas emissions released during natural gas pipeline incidents), and promote environmental justice for minority populations, low-income populations, and other underserved and disadvantaged communities that are located near interstate gas transmission pipelines.

Although the Federal Pipeline Safety Regulations (49 Code of Federal Regulations (CFR) parts 190 through 199; PSR) applicable to gas transmission and gathering pipeline systems set forth in parts 191 and 192 have increased the level of safety associated with the transportation of gas, serious safety incidents continue to occur on gas transmission and gathering pipeline systems, resulting in serious risks to life and property. In its investigation of the 2010 PG&E incident, the National Transportation Safety Board (NTSB) found among several causal factors that PG&E had an inadequate integrity management (IM) program that failed to detect and repair or remove a defective pipe section on its gas transmission line.[1] PG&E based its IM program on incomplete and inaccurate pipeline information, which led to, among other issues, faulty risk assessments, improper assessment method selections, and internal assessments of the program that were superficial and resulted in no meaningful improvement.[2]

Prior to the PG&E incident, PHMSA had initiated an advance notice of proposed rulemaking (ANPRM) to seek comment on whether the IM requirements in part 192 should be changed and whether other issues related to pipeline system integrity should be addressed by strengthening or expanding non-IM requirements.

[1] NTSB, NTSB/PAR–11–01, ''Pipeline Accident Report: Pacific Gas and Electric Company, Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010'' (2011) (NTSB Incident Report on San Bruno).

[2] NTSB Incident Report on San Bruno at 107–115.

PHMSA published the ANPRM on August 25, 2011.[3]

Based on the comments on the ANPRM, PHMSA published a notice of proposed rulemaking (NPRM) on April 8, 2016, to seek public comments on proposed changes to the PSR governing transmission and gathering lines.[4] A summary of those proposed changes pertaining to this rulemaking, corresponding stakeholder feedback, and PHMSA's responses to stakeholder feedback on the individual provisions, is provided below in section III of this document (Discussion of NPRM Comments, GPAC Recommendations, and PHMSA Response).

PHMSA determined that the most efficient way to manage the proposals in the NPRM was to divide them into three separate final rule actions. The first of these final rules was published on October 1, 2019, and addressed topics primarily relating to congressional mandates and safety recommendations, including maximum allowable operating pressure (MAOP) reconfirmation and material properties verification, the expansion of integrity assessments beyond high-consequence areas (HCA), the consideration of seismicity, in-line inspection (ILI) launcher and receiver safety, MAOP exceedance reporting, and strengthened requirements for assessment methods (2019 Gas Transmission Rule).[5] Provisions related to gas gathering pipelines were addressed in a separate rulemaking.[6] This rulemaking finalizes the remaining provisions from the NPRM as outlined below.

B. Summary of the Major Provisions of the Final Rule

To reduce the risks of pipeline incidents, PHMSA is amending the PSR applicable to gas transmission pipelines to improve the protection of the public, property, and the environment; close regulatory gaps; and adopt additional safety measures to improve safety inside and outside of HCAs. Specifically, PHMSA is making changes to clarify the IM requirements; improve the management of change (MOC) process; strengthen corrosion control requirements; provide parameters for inspections following extreme weather events; strengthen requirements related to the IM assessment methods; and improve the repair criteria for pipeline anomalies. PHMSA is also amending certain definitions in part 192 in support of these provisions.

PHMSA is modifying the IM regulations by adding specificity to the data integration language. The final rule establishes several pipeline attributes that must be included in an operator's risk analysis when an operator determines what threats are applicable to a pipeline segment. PHMSA is also explicitly requiring that operators integrate analyzed information into their IM programs and is requiring that data be verified and validated. Additionally, PHMSA is issuing requirements for applying knowledge gained through an operator's IM program, including provisions for analyzing interacting threats, potential failures, and worst-case incident scenarios from the initial failure to incident termination. Several of these items were proposed in response to NTSB findings following the PG&E incident that suggested pipeline operators were often not conducting data analysis, data integration, threat identification, and risk assessment in the manner originally intended and specified in subpart O of part 192.

Similarly, following the PG&E incident, PHMSA, informed by (inter alia) the NTSB's evaluation of the incident and ANPRM comments, determined that the existing MOC requirements and industry practices were not sufficient[7] and looked to align the regulatory requirements with the standards outlined in American Society of Mechanical Engineers/American National Standards Institute (ASME/ANSI) B31.8S.[8] Specifically, this final rule requires each operator of an onshore gas transmission pipeline to develop and follow a MOC 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.

This final rule also improves and updates the corrosion control requirements for gas transmission pipeline operators. Based on lessons PHMSA has learned following several pipeline failures, and following PHMSA's workshop on pipeline construction in Fort Worth, TX, on April 23, 2009,[9] PHMSA determined that construction practices, including the installation of pipe in-ditch, can result in damaged coating that can compromise corrosion control. Therefore, this rule requires that operators perform assessments to identify suspected damage promptly after backfilling and then remediate any coating damage found. Further, PHMSA has noted that the existing regulations were not always effective at eliminating deficiencies in cathodic protection[10] corrosion control or at preventing incidents from internal corrosion. Therefore, this rule strengthens the requirements for internal and external corrosion controls related to monitoring requirements and surveys. PHMSA also determined that additional prescriptive preventive and mitigative (P&M) measures are needed for managing electrical interference currents.

Extreme weather has been a contributing factor in several pipeline failures. PHMSA issued Advisory Bulletins in 2015, 2016, and 2019 to communicate the potential for damage to pipeline facilities caused by severe flooding, including actions that operators should consider taking to ensure the integrity of pipelines in the event of flooding, river scour, river channel migration, and earth movement.[11] As PHMSA has noted in another series of Advisory Bulletins, hurricanes are also capable of causing extensive damage to both offshore and inland pipelines.[12]

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[3] "Safety of Gas Transmission Pipelines," 76 FR 53086 (Aug. 25, 2011).

[4] "Safety of Gas Transmission and Gathering Pipelines," 81 FR 20722 (Apr. 8, 2016).

[5] "Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments," 84 FR 52180 (Oct. 1, 2019).

[6] "Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulations of Large, High-Pressure Lines, and Other Related Amendments," 86 FR 63266 (Nov. 15, 2021) (Gas Gathering Final Rule).

[7] See 81 FR 20796; NTSB Incident Report on San Bruno at 95–97 (concluding that the probable cause of the PG&E incident was PG&E's inadequate quality assurance and quality control in 1956 during its Line 132 relocation project, and noting that PG&E had poor quality control during a pipe installation project that later failed in 2008 in Rancho Cordova, CA).

[8] ASME/ANSI "B31.8S–2004: Supplement to B31.8 on Managing System Integrity of Gas Pipelines" (Jan. 14, 2005).

[9] *https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=58.*

[10] Cathodic protection is a technique used to control corrosion by making the metal pipe a cathode of an electrochemical cell. Essentially, the pipeline is connected to a more easily corroded metal that acts as an anode. That "sacrificial anode" metal corrodes instead of the metal that is being protected. For pipelines, passive galvanic cathodic protection is often not adequate, and an external direct current (DC) electrical power source is used to provide sufficient current.

[11] "Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Flooding, River Scour, and River Channel Migration," 80 FR 19114 (Apr. 9, 2015); "Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Flooding, River Scour, and River Channel Migration," 81 FR 2943 (Jan. 19, 2016); "Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards," 84 FR 18919 (May 2, 2019).

[12] "Potential for Damage to Pipeline Facilities Caused by the Passage of Hurricane Ivan," 69 FR 57135 (Sept. 23, 2004); "Pipeline Safety Advisory: Potential for Damage to Pipeline Facilities Caused by the Passage of Hurricane Katrina," 70 FR 53272 (Sept. 7, 2005); "Pipeline Safety: Potential for

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Because of the frequency and severe consequences of these events,[13] operators must protect the public from pipeline risks in the event of a natural disaster or extreme weather. While many prudent operators might voluntarily perform inspections following such events, the potential risk to public safety and environment merits codification of those practices in regulatory requirements. Therefore, PHMSA is amending the PSR to require that operators commence inspection of their potentially affected facilities within 72 hours after the operator determines the affected area can be safely accessed following the cessation of an extreme weather event such as a hurricane, landslide, flood; a natural disaster, such as an earthquake; or another similar event that has the likelihood to damage infrastructure. If an operator finds an adverse condition during the inspection, the operator must take appropriate remedial action to ensure the safe operation of the pipeline.[14]

PHMSA is also strengthening the standards for performing pipeline assessments by incorporating by reference certain consensus standards for both stress corrosion cracking (NACE International Standard Practice 0204–2008, ''Stress Corrosion Cracking Direct Assessment Methodology'' (2008) (NACE 0204–2008)) and internal corrosion direct assessments (NACE International Standard Practice 0206–2006, ''Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas'' (2006) (NACE SP0206–2006)). Operators are already required to assess the condition of gas transmission pipelines in HCAs and certain non-HCAs periodically in accordance with §§ 192.710, 192.921, and 192.937. When the initial IM regulations creating subpart O were issued in 2003 (2003 IM rule), industry standards did not exist for these types of assessments.[15] By incorporating by reference the standards subsequently published by NACE International,[16] PHMSA is ensuring greater consistency, accuracy, and quality when operators perform these assessments.

This final rule also updates the existing repair criteria for HCAs by incorporating criteria for additional anomaly types such as crack anomalies, certain corrosion metal loss defects, and certain mechanical damage defects. Such revisions will provide greater assurance that operators will repair injurious anomalies and defects before those defects grow to a size that causes a leak or rupture. PHMSA also is finalizing explicit repair criteria for non-HCAs. Prior to this final rule, there were only general requirements in the regulations for operators to perform repairs in non-HCAs. The content of the non-HCA repair criteria being finalized in this rule is consistent with the criteria for HCAs; however, PHMSA has provided longer timeframes for the remediation of conditions that are not categorized as ''immediate'' conditions to provide operators the ability to prioritize remediating anomalous conditions in HCAs where consequences of a pipeline failure may be greater.

The various changes in this rule have also prompted additions and changes to certain definitions in part 192. PHMSA has created or made changes to the following terms: ''close interval survey,'' ''distribution center,'' ''dry gas or dry natural gas,'' ''hard spot,'' ''in-line inspection (ILI),'' ''in-line inspection tool or instrumented internal inspection device,'' ''transmission line,'' and ''wrinkle bend.''

C. Costs and Benefits

PHMSA has prepared an assessment of the benefits and costs of the final rule as well as reasonable alternatives. PHMSA estimates the annual costs of the rule to be approximately $17 million, calculated using a 7 percent discount rate. The costs reflect improvements made to the MOC process, additional corrosion control requirements, the provisions related to inspections following extreme weather events, and the changes made to the repair criteria. PHMSA finds that the other final rule requirements will not result in incremental costs.

PHMSA is posting the Regulatory Impact Analysis (RIA) for this rule in the public docket. PHMSA has determined that the regulatory amendments adopted in this final rule will improve public safety, reduce threats to the environment (including, but not limited to, reduction of methane emissions contributing to the climate crisis), and promote environmental justice for minority populations, low-income populations, and other underserved and disadvantaged communities. PHMSA finds the regulatory amendments adopted in this final rule are technically feasible, reasonable, cost-effective, and practicable because the public safety, environmental, and equity benefits of its regulatory amendments described herein and within its supporting documents (including the RIA and environmental assessment, each available in the docket for this rulemaking) will justify any associated costs and demonstrate and the superiority of the final rule compared to alternatives.

II. Background

A. Overview

On September 9, 2010, a 30-inch-diameter natural gas transmission pipeline, owned and operated by PG&E, ruptured in a residential neighborhood in San Bruno, CA. The rupture produced a crater approximately 72 feet long by 26 feet wide. The segment of pipe that ruptured weighed approximately 3,000 pounds, was 28 feet long, and was found 100 feet south of the crater. When the escaping gas ignited, the resulting fire killed 8 people, injured approximately 60 more, destroyed or damaged 108 homes, and caused the evacuation of over 300 people. In its pipeline accident report for the incident, the NTSB determined that the probable cause of the incident was PG&E's inadequate quality control and assurance when it relocated the line in 1956 and its inadequate IM program. The NTSB determined that PG&E's IM program was deficient and ineffective because it was based on incomplete and inaccurate pipeline information, did not consider how the pipeline's design and materials contributed to the risk of a pipeline failure, and failed to consider the presence of previously identified welded seam cracks as part of its risk assessment. These deficiencies resulted in the selection of an assessment method that could not detect welded seam defects and led to internal assessments of PG&E's IM program that were superficial and resulted in no improvements. Ultimately, this inadequate IM program failed to detect and repair or replace the defective pipe section.

Damage to Pipeline Facilities Caused by the Passage of Hurricanes,'' 76 FR 54531 (Sept. 1, 2011) (alerting operators to the potential for damage from Hurricane Ivan).

[13] For the impacts of climate change on precipitation; droughts, floods, and wildfire; and extreme storms, see U.S. Global Change Research Program, ''Climate Science Special Report: Fourth National Climate Assessment, Volume 1,'' at ch. 7–9 (2017).

[14] PHMSA notes that these part 192 amendments are consistent with similar provisions adopted for part 195 for hazardous liquid pipelines. See ''Pipeline Safety: Safety of Hazardous Liquid Pipelines,'' 84 FR 52260 (Oct. 1, 2019).

[15] ''Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines): Final Rule,'' 68 FR 69778 (Dec. 15, 2003).

[16] In 2021, NACE International merged with the Society for Protective Coatings, becoming the Association for Materials Protection and Performance (AMPP). They will continue to be referred to as NACE International throughout this document.

In response to this incident, Congress, the NTSB, and the Government Accountability Office (GAO) called for PHMSA to improve IM and address other weaknesses and gaps in the PSR. As described in more detail in the sections that follow, this is the second of three planned rulemakings that are the culmination of this rulemaking initiative.

B. Advance Notice of Proposed Rulemaking

On August 25, 2011, PHMSA published an ANPRM to seek public comments regarding potential revisions to the PSR pertaining to the safety of gas transmission and gathering pipelines. PHMSA requested comments on 122 questions spread across 15 broad issues involving IM and non-IM requirements. The issues related to IM requirements included whether the definition of an HCA should be revised and whether additional restrictions should be placed on the use of certain pipeline assessment methods. The issues related to non-IM requirements included whether revised requirements were needed for mainline valve spacing and actuation, whether requirements for corrosion control should be strengthened, and whether new regulations were needed to govern the safety of gas gathering lines and underground natural gas storage facilities. Based on the comments received on several of the ANPRM topics, PHMSA developed specific proposals for some of those topics in an NPRM that was the basis for this final rule.

C. Notice of Proposed Rulemaking and Subsequent Final Rule

On April 8, 2016, PHMSA published an NPRM seeking public comments on proposed revisions to the PSR pertaining to the safety of onshore gas transmission pipelines and gas gathering pipelines. PHMSA considered the comments it received from the ANPRM and proposed new pipeline safety requirements and revisions of existing requirements in several major topic areas. A summary of the NPRM proposals and topics pertinent to this rulemaking, the comments received on those specific proposals, and PHMSA's response to the comments received, is provided under section III (Discussion of NPRM Comments, GPAC Recommendations, and PHMSA Response).

On October 1, 2019, PHMSA promulgated a subset of the rules proposed in the NPRM by issuing the first of three planned final rules. In that rule, PHMSA addressed gas transmission pipelines and established minimum Federal safety standards for MAOP reconfirmation, pipeline physical material properties verification, the expansion of integrity assessments beyond HCAs, the consideration of seismicity in an operator's risk assessment and P&M measures, ILI tool launcher and receiver safety, MAOP exceedance reporting, and strengthened requirements for IM assessment methods.

This final rule, the second of three planned rules, finalizes several proposed amendments in the NPRM related to gas transmission pipelines, including provisions related addressing repair criteria, IM improvements, cathodic protection, MOC processes, and other related amendments. A separate rulemaking, dealing with the safety of onshore gas gathering pipelines, was the subject of a final rule published on November 15, 2021, and extended reporting and safety requirements to certain gathering pipelines that were formerly not subject to Federal safety oversight. PHMSA estimated in that Gas Gathering Final Rule that there were over 400,000 miles of gas gathering pipelines that were not subject to minimum Federal pipeline safety standards, including basic incident and mileage reporting. The Gas Gathering Final Rule extended annual and incident reporting requirements to all gathering pipelines and defined a new category of ''Type C'' gathering pipelines to address the safety of larger-diameter, higher-pressure onshore gathering pipelines that were formerly unregulated. The scope of the requirements for Type C gas gathering pipelines are risk-based; basic damage prevention provisions apply to all Type C gas gathering pipelines while other safety requirements apply to larger-diameter Type C gas gathering pipelines or those Type C gas gathering pipelines that are located near buildings intended for human occupancy.

III. Discussion of NPRM Comments, Gas Pipeline Advisory Committee Recommendations, and PHMSA Response

The comment period for the NPRM ended on July 7, 2016. PHMSA received approximately 300 submissions to the docket containing thousands of comments on the NPRM. Submissions were received from the NTSB; groups representing the regulated pipeline industry; groups representing public interests, including environmental groups; State utility commissions and regulators; members of Congress; individual pipeline operators; and private citizens. PHMSA also received late-filed comments to this rulemaking from the major industry trade associations and others following advisory committee meetings as discussed below. Consistent with DOT Order 2100.6 and 190.323, PHMSA considered all comments, including those that were filed late, given their relevance to the rulemaking and the absence of additional expense or delay resulting from considering these comments.

Some of the comments PHMSA received in response to the NPRM were considered in finalizing the 2019 Gas Transmission Rule targeted at statutory mandates, while other comments were considered in response to the third final rule on gas gathering pipelines (under RIN 2137–AE38). In this final rule, PHMSA considers those comments that are relevant to repair criteria, IM improvements, cathodic protection, MOC, and other related amendments. PHMSA does not address the comments on pipeline safety issues that were beyond the scope of the NPRM and, therefore, beyond the scope of this final rule. However, that does not mean that PHMSA determined the comments lack merit or do not support additional rules or amendments. Such issues may be the subject of other existing rulemaking proceedings or may be addressed in future rulemaking proceedings. The remaining comments reflect a wide variety of views on the merits of particular sections of the proposed regulations.

The Technical Pipeline Safety Standards Committee, commonly known as the Gas Pipeline Advisory Committee (GPAC or ''the committee''), is a statutorily mandated advisory committee that advises and comments on PHMSA's proposed safety standards, risk assessments, and safety policies for natural gas pipelines prior to their final adoption. The GPAC is one of two pipeline advisory committees focused on technical safety standards that were established under the Federal Advisory Committee Act (Pub. L. 92–463) and section 60115 of the Federal Pipeline Safety Statutes (49 U.S.C. 60101 *et seq.*). Each committee consists of approximately 15 members, with membership equally divided among Federal and State agencies, regulated industry, and the public. The committees consider the ''technical feasibility, reasonableness, cost-effectiveness, and practicability'' of each proposed pipeline safety standard and provide PHMSA with recommended actions pertaining to those proposals.

Due to the size and technical detail of the NPRM, the GPAC met 5 times in 2017 and 2018 to discuss the proposed regulations applicable to gas transmission pipelines. The GPAC convened one time in 2019 to discuss the provisions related specifically to gas gathering pipelines.[17] During those meetings, the GPAC considered the specific regulatory proposals of the NPRM and discussed various comments made on the NPRM's proposal by stakeholders, including the pipeline industry at large, public interest groups, and government entities. To assist the GPAC in its deliberations, PHMSA presented a description and summary of the major proposals in the NPRM and the comments received on those issues. Stakeholders could comment on the proposals during the meeting prior to the committee discussion. PHMSA assisted the committee in fostering discussion and developing recommendations by providing direction on which issues were most pressing.

For the proposals addressed in this final rule, the committee came to consensus when voting on the technical feasibility, reasonableness, cost-effectiveness, and practicability of the NPRM's provisions. In many instances, the committee recommended changes to certain proposals that the committee found would make the rule more feasible, reasonable, cost-effective, or practicable.

This section discusses the substantive comments on the NPRM that were submitted to the docket, as well as the GPAC's recommendations. They are organized by topic and include PHMSA's response to, and resolution of, those comments.

A. IM Clarifications—§§ 192.917(a)–(d), 192.935(a)

i. Threat Identification, Data Collection, and Integration—§ 192.917(a) and (b)

1. Summary of PHMSA's Proposal

Subpart O of 49 CFR part 192 prescribes requirements for managing pipeline integrity in HCAs and requires that operators identify and evaluate all potential threats to each covered pipeline segment. Operators are required to identify threats to which the pipeline is susceptible, collect data for analysis, and perform a risk assessment that informs the operator's baseline assessment schedule and reassessment intervals as well as any additional P&M measures that may be needed for the covered segment. The regulations also require operators to address particular threats, such as third-party damage and manufacturing and construction defects. For these requirements, the regulations reference, through incorporation, ASME/ANSI B31.8S.

For threat identification, the regulations in § 192.917 specify that the potential threats operators must consider include, but are not limited to, the threats listed in section 2 of ASME/ANSI B31.8S. Those threats are grouped into time-dependent threats, static or resident threats, time-independent threats, and human error. In performing data gathering and integration, operators must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, operators must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S, which are the year of installation; pipe inspection reports; leak history; wall thickness; diameter; past hydrostatic test information; gas, liquid, or solid analysis; bacteria culture test results; corrosion detection devices; operating parameters; and operating stress level. An operator must also conduct a risk assessment that follows ASME/ANSI B31.8S section 5.

In a risk-based IM approach, data collection and integration is the backbone of an effective IM program. The PG&E incident exposed several problems in the way operators collect and manage pipeline condition data, showing that some operators have inadequate records regarding the physical and operational characteristics of their pipelines. The use of erroneous information leads to insufficient understanding of pipeline risks and incorrect integrity-related decision making. PG&E's IM program was missing or misidentified data elements that were necessary to characterize risk correctly and establish and validate MAOP, which is critically important for providing an appropriate margin of safety to the public.

Threat identification, data collection, and data integration are basic pillars on which IM was founded with the issuance of the 2003 IM rule. As specified in § 192.907(a), operators were to start with a framework, evolve that framework into a more detailed and comprehensive program, and continually improve their IM programs.[18] Operators would accomplish this constant improvement, in part, through learning about the IM process itself and learning more about the physical condition of their pipelines via IM assessments and the development of that data.

Data collection for new pipeline construction is relatively simple. However, collecting missing material property records for pipeline segments that have been in the ground for years can be challenging, as such data collection must be completed through integrity assessments or excavations. Operators are required to identify missing data and apply conservative assumptions, but incomplete data presents issues for risk assessment. The over-application of assumptions in the absence of real data, even if those assumptions are conservative, can lead to skewed or otherwise inaccurate risk analysis results.

In the NPRM, PHMSA proposed to revise § 192.917 to include specific requirements for collecting, validating, and integrating pipeline data. These requirements would add further specificity to the data integration regulations, list specific pipeline attributes that must be included in these analyses, explicitly require that operators integrate analyzed information, and require that data be verified and validated. PHMSA also proposed to require that operators use validated, objective data to the maximum extent practical. To the degree that subjective data from subject matter experts (SME) must be used, PHMSA would require that operator programs include specific features to compensate for SME bias, including training SMEs to recognize or avoid bias, and using outside technical experts or independent expert reviews to assess SME judgment and logic. Further, in § 192.917(b)(3), PHMSA proposed to require operators to identify and analyze spatial relationships among anomalous information (*e.g.,* corrosion coincident with foreign line crossings and evidence of pipeline damage where overhead imaging shows evidence of encroachment), stating that storing or recording the information in a common location, including a geographic information system (GIS) alone, is not sufficient.

2. Summary of Public Comment

Many stakeholders agreed with PHMSA that verified and validated data is important for data integration and threat analysis. The NTSB expressed support for the proposed additions to the IM analysis requirements and commented that expanded pipeline record and data requirements are a significant safety improvement in the management of pipelines through their service lifecycle. However, certain

[17] Specifically, the committee met on January 11–12, 2017; June 6–7, 2017; December 14–15, 2017; March 2, 2018; March 26–28, 2018; and June 25–26, 2019. Information on these meetings can be found at *regulations.gov* under docket no. PHMSA–2011–0023 and at PHMSA's public meeting page: *https://primis.phmsa.dot.gov/meetings/.*

[18] See 68 FR 69789.

stakeholders had concerns with PHMSA's specific proposed changes.

PHMSA also received comments from the industry on the feasibility of threat identification, data gathering, and integration. The American Petroleum Institute (API) stated that while the totality of attributes listed in proposed § 192.917 should not pose a major burden on the industry, some specific attributes listed may not be feasible to obtain in practice. Enterprise Products stated that including just four or five attributes that point to a specific conclusion would be more useful than the lengthy list of attributes in the proposed provisions. A few commenters requested PHMSA clarify what they meant by ''data integration, verification, and validation,'' as these terms were not clear.

The Interstate Natural Gas Association of America (INGAA) and the Texas Pipeline Association (TPA) expressed concern that the proposed provisions are more prescriptive than the ASME/ANSI standard that is referenced in the current IM requirements. INGAA also commented that PHMSA's proposed inclusion of specific attributes from ASME/ANSI B31.8S in the regulatory text alongside the existing incorporation by reference of that standard could cause confusion. INGAA further stated that PHMSA should retain the current regulatory language requiring operators to ''consider'' the relevant data for covered segments and similar non-covered segments, instead of adopting the proposed provisions that would require data evaluation for non-covered segments. INGAA also stated that many of the data elements required by ASME/ANSI B31.8S are not available for older pipelines, which can include non-covered segments. INGAA and other commenters also asserted that PHMSA should provide sufficient time for operators to comply with the proposed data validation and integration requirements given the expansion of § 192.917(b)(1) to non-covered segments.

Several commenters provided input on PHMSA's proposed requirements to address SME bias. INGAA suggested PHMSA should delete the references to SME bias listed in § 192.917(b)(2) and replace the text with more general language to include peer reviews and external SME verification, citing this alternative as more consistent and clearer than what PHMSA proposed. National Fuel stated that using outside technical experts for bias control would be unnecessarily costly to pipeline operators. The American Gas Association (AGA) asserted that using outside technical subject matter experts for bias control is already standard practice within the industry and that it is not necessary to codify it into regulation. PG&E also suggested improvements to the section, stating that there is not an existing industry standard to provide guidance on what constitutes an outside technical expert to perform this specific function, and PHMSA should provide further guidance on this topic.

Several industry trade groups provided input on the proposed language in § 192.917(b)(3) that would require operators to identify and analyze the spatial relationship among anomalous information (*e.g.,* corrosion coincident with foreign line crossings and evidence of pipeline damage where overhead imaging shows evidence of encroachment). TPA stated that it disagreed with PHMSA's proposal in this paragraph and commented that this requirement would impose a financial burden on smaller operators. PG&E asserted that the proposed language in § 192.917(b)(3) should be removed entirely since it was not clear how to comply with these requirements.

At the GPAC meeting on June 7, 2017, the committee noted that the NPRM's proposed revisions to § 192.917 do not include a way for operators to address the lack of availability of some data sets. The committee suggested that operators could assume the pipeline segment is susceptible to the threat associated with the missing data. The committee also questioned the purpose for the extensive, prescriptive data list, with some members believing it would turn into a compliance paperwork exercise without safety benefit. This, in turn, led to a discussion of how an operator demonstrates to a regulator that it is performing an effective risk analysis and whether that is a checklist of items or performing actions to generate better safety outcomes. Some committee members suggested PHMSA clarify that operators should only collect the pertinent data for operations and maintenance (O&M) tasks.

Committee members representing the industry noted the rule has no timeframe for the implementation of data collection and challenged the conclusion in the preliminary regulatory impact assessment (PRIA) that the data collection elements had a cost of zero, as databases may need to be upgraded to implement the listed attributes. Members representing the industry also requested PHMSA remove the proposed requirement to address SME bias; however, other committee members representing the public noted that SME bias in risk analysis is recognized across different disciplines and reflects a need to address how humans think about risk. Certain committee members representing the industry were also concerned that the requirements mandated the use of a GIS, which might be impractical for small operators.

Following the discussion, the committee voted 11–0 that the proposed rule, as published in the **Federal Register**, with regard to the provisions for IM clarifications regarding threat identification, data collection, and data integration, were technically feasible, reasonable, cost-effective, and practicable if PHMSA revised the list of pipeline attributes in the section to be more consistent with the existing regulations and the ASME/ANSI B31.8S standard, and if PHMSA also added language requiring operators to collect data that is pertinent and that a prudent operator would collect. The committee also recommended PHMSA require operators to have implementation procedures in place 1 year after the effective date of the rule, with full incorporation of all listed attributes by 3 years after the effective date of the rule, and strike requirements for operators to use a GIS in complying with these provisions. Finally, the committee recommended that PHMSA address SME bias by considering some of the specific suggestions made by committee members at the meeting, including striking or revising the last sentence of the provisions.

3. PHMSA Response

The current regulations at § 192.917(b) explicitly require that, at a minimum, an operator must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S. Operators may not ignore that requirement to collect the minimum set of data needed for a robust threat evaluation and risk assessment. PHMSA agrees that some assumptions regarding threat applicability based upon pipe type, operating parameters, and operating environment (*i.e.,* weld seam type, manufacturing date, coating type, operating pressure versus percentage specified minimum yield strength (SMYS), operating temperature, lack of cathodic protection (CP) or the time when CP was placed on the system, and location) can be made even if the pertinent data is missing. For example, a lack of CP on a pipeline system would mean that the pipeline is more prone to external corrosion, no matter what type of external coating is on the pipe. High operating temperatures, pressures, and a lack of quality pipe coating can also be risk factors for cracking.

Regarding INGAA's comment on retaining the current regulatory language requiring operators to ''consider'' the relevant data for covered segments and similar non-covered segments rather than adopting the proposed provisions that would require data evaluation for non-covered segments, PHMSA reminds operators that the current requirement states that operators must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. At a minimum, operators must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S and consider both on the covered segment and similar non-covered segments the data and conditions specific to each pipeline. PHMSA's clarification in this final rule that operators must ''analyze'' the information that they are already required to collect, integrate, and consider, is consistent with the existing requirement, as performing those actions is, essentially, an analysis. Nevertheless, PHMSA is changing ''consider'' to ''analyze'' to reinforce that operators must have documentation demonstrating that they have reviewed the data for similar vintage pipe to determine whether they have threats or not that should be remediated.

PHMSA further disagrees that it is appropriate to allow industry to continue to ''consider'' data elements selectively or that only specifying a few required data elements is the best approach. While some pipelines without associated data may not pose a risk, some may pose a significant risk. Comprehensive data is the best way to ensure an appropriate assessment and, in turn, reduction of risk. The addition of the specific data elements in the regulatory text clarifies PHMSA's expectations of data collection. PHMSA agrees, however, that some data elements may not be pertinent to all pipeline segments. Therefore, in this final rule, PHMSA is revising the proposed requirement to specify that the operator must collect ''pertinent'' data ''about pipeline attributes to assure safe operation and pipeline integrity, including information derived from operations and maintenance activities,'' as recommended by the GPAC. Regarding the cost of this data collection, all the proposed elements were listed in ASME/ANSI B31.8S. As that standard has been incorporated by reference since 2004 for covered segments (*i.e.,* HCAs), collecting the listed data should not be a new or an extensive exercise for any prudent operator with appropriate processes in place. While specifying the list of data elements in the regulatory text is new, the elements listed have been incorporated by reference since the promulgation of subpart O and are not more prescriptive than the current regulations. Further, PHMSA disagrees that continuing to incorporate by reference ASME/ANSI B31.8S as well as specifying individual data elements will confuse operators.

Additionally, in response to comments and the GPAC recommendation, PHMSA is revising the listing of data elements to be more consistent with ASME/ANSI B31.8S. In some cases, PHMSA has clarified the meaning of generic terms in the data collection list found in ASME/ANSI B31.8S within this final rule. For example, where the ASME/ANSI standard lists ''material properties,'' PHMSA has elaborated by specifying these are ''material properties including, but not limited to, grade, SMYS, and ultimate tensile strength.'' In another example, where the standard lists ''pipe inspection reports,'' PHMSA has itemized, in this final rule, the pipe inspections required by part 192 and that are commonly performed by operators.

PHMSA agrees with commenters that sufficient time should be allotted for operators to comply with the data integration requirements. However, PHMSA also agrees with the comments made that operators should have been collecting and accounting for the pertinent items of this data set since the publication of the original IM rule almost 20 years ago. Therefore, in this final rule, PHMSA is providing a phased-in timeframe. The GPAC recommended that the implementation timeframe should begin in year 1, with full incorporation by 3 years. Given the existing requirements for collecting and using the data elements from ASME/ANSI B31.8S, and given the discussion at the GPAC meetings and the public comments received, PHMSA has revised this final rule to require that an operator must begin data integration on the effective date of the rule and integrate all attributes within 18 months of this rule's publication date.

Regarding comments calling for clarification of what ''data integration, verification, and validation'' meant, PHMSA notes that, at a minimum, an operator should consider the same set of data on a periodic basis and analyze changes and trends that would indicate the need for additional integrity evaluations.

Regarding SME bias, PHMSA believes that it is important for operators to address SME bias in data collection and risk assessment to account for the reality of how humans think about risk. Operators should take this into consideration when incorporating SME opinion as fact or when treating input from all SMEs as equivalent. While some operators may effectively account for SME bias, PHMSA has not observed this to be universal practice in the industry. To the point commenters made that using outside technical experts for bias control is unnecessarily costly, PHMSA notes that the use of outside technical experts would be optional: this final rule contemplates that operators could also employ training to ensure information provided by their own SMEs is consistent and accurate. While commenters also correctly noted that there is not an existing industry standard as to what constitutes an outside technical expert or an independent technical expert for SME bias control, an operator is ultimately responsible for determining the appropriateness and conductors of such a review. As a part of such a review, should an operator decide to have another SME review input from another SME, the operator must use a qualified SME—*e.g.,* an individual with formal or on-the-job technical training in the technical or operational area being analyzed, evaluated, or assessed. Operators would be required to document that the SME is appropriately knowledgeable and experienced in the subject being assessed.

PHMSA was persuaded, consistent with a GPAC recommendation, that some adjustments to the rule language are appropriate for clarity, or to eliminate redundant language, within the non-exhaustive list of specific types of data to be collected at § 192.179(a) and (b). Specific changes adopted in this final rule include the following:

- Section 192.917(a)(2): deleted a redundant reference to ''or equipment defects;''
- Section 192.917(b)(1)(iii): deleted explicit material properties (*e.g.,* hardness, chemical composition) from a non-exhaustive list of material properties;
- Section 192.917(b)(1)(xxiv): added ''seam cracking'' within the list of pipe operational and maintenance inspection reports to be reviewed;
- Section 192.917(b)(1)(xxv): deleted a redundant reference to ''outer/inner diameter corrosion monitoring;''
- Section 192.917(b)(1)(xxviii): eliminated specific examples of ''encroachments;'' and
- Section 192.917(b)(1)(xxxvi): deleted a redundant savings clause for ''other pertinent information'' when the lead-in to the section noted that the information listed was non-exhaustive.

PHMSA has also, consistent with a recommendation by the GPAC revised the rule by (1) requiring that operators employ adequate control measures for SME input to ensure consistent and accurate information rather than ''correct'' SME ''bias;'' and (2) requiring that operators document the names and qualifications of individuals who approve SME input rather than document the names of the SMEs and the information provided.

Concerning the use of a GIS, the NPRM's proposed revisions to § 192.917 were not intended to imply that all operators were required to implement a GIS system but were meant to clarify that data integration is not achieved solely by maintaining spatially located data in a GIS system. Accordingly, PHMSA has revised this final rule as recommended by the GPAC to delete reference to the use of a GIS system and maintain the core requirement to identify and analyze spatial relationships among anomalous information.

A. IM Clarifications—§§ 192.917(a)–(d), 192.935(a)

ii. Risk Assessment Functional Requirements—§ 192.917(c)

1. Summary of PHMSA's Proposal

Section 192.917(c) requires operators to perform a risk assessment as part of an effective IM program. A risk assessment is an important element of a good IM plan. PHMSA analyzed the issues related to risk assessments that the NTSB identified in its investigation and held a workshop on July 21, 2011, to address perceived shortcomings in the implementation of IM risk assessments. PHMSA also sought input from stakeholders on these issues in the ANPRM. Based on the input received from both the ANPRM and the workshop, PHMSA determined that additional clarification was needed to emphasize the functions that risk assessments must accomplish and to elaborate on effective processes for risk management, both of which are critical to effective IM.

To address these issues, PHMSA proposed to clarify the risk assessment aspects of the IM regulations at subpart O by including the following functional requirements for risk assessments that operators should perform to assure pipeline integrity:

- Evaluate the effects of interacting threats;
- Ensure validity of the methods used to conduct the risk assessment;
- Determine additional P&M measures needed;
- Analyze how a potential failure could affect an HCA, including the consequences of the entire worst-case incident scenario, from initial failure to incident termination;
- Identify how each risk factor, or each combination of risk factors that simultaneously interact, contribute to risk at a common location;
- Account and compensate for uncertainties in the model and the data used in the risk assessment; and
- Evaluate risk reduction associated with candidate activities, such as P&M measures.

2. Summary of Public Comment

Public interest groups supported PHMSA's proposed revisions at § 192.917(c) to strengthen the functional requirements for risk assessment models. The Pipeline Safety Trust (PST) stated that the risk assessment models currently used by pipeline operators are inadequate and further noted that the proposed provisions could go farther to advance risk assessment quality. Other GPAC members representing the public supported the proposed revisions at § 192.917(c) during the committee meetings and noted that the NPRM language for this topic was written using a risk-informed approach that articulated the functions and purposes of risk assessments without being prescriptive as to the method or process to be used, which is consistent with IM principles.

Multiple industry trade associations and individual operators acknowledged the importance of risk assessments but believed that the proposed revisions at § 192.917(c) were too prescriptive. Several individual operators emphasized their voluntary efforts to improve their risk models and disagreed that the industry's risk models needed further prescription.

Many commenters emphasized that different pipeline systems are susceptible to different threats and believed that operators are best suited to determine which threat analyses are relevant to their systems. Multiple operators expressed the opinion that the proposed revisions at § 192.917(c) would require operators to expand datasets substantially but would contribute little benefit to risk identification, suggesting instead that integrating unnecessary datasets would distract from other safety efforts. AGA and several individual operators requested that PHMSA give operators discretion to select which data sets to incorporate into risk assessments for their system.

Some commenters requested that PHMSA specify what the NPRM meant when it proposed to revise § 192.917(c) to require operators to ''validate'' data. These commenters expressed doubts regarding the technical feasibility of implementing the proposed regulations in § 192.917(c), noting that some of the data PHMSA proposed requiring for the validation of risk assessment models is not available. These commenters proposed that operators be permitted to apply conservative values or values determined using engineering judgement. Southwest Gas Corporation, Paiute Pipeline, and Consumers Pipeline expressed concern that developing the newly required datasets would require the usage of ILI tools that their pipelines are not configured to accommodate. These commenters stated that gathering these datasets would present costs that were not captured by PHMSA's PRIA because PHMSA did not account for the cost of making lines piggable.

Multiple commenters were concerned that the proposed revisions would make operators' current relative risk models invalid and would require a transition to quantitative or probabilistic risk models. Similarly, API agreed with that assessment and noted that quantitative and probabilistic models are not useful or appropriate for the analysis, prediction, or prevention of low-frequency, high-consequence events such as the PG&E incident. Further, API noted that the probabilities of certain infrequent circumstances and conditions occurring at a single location and single time are so low that the quantitative or probabilistic risk models would not identify them because there are no statistics available from which to predict them. AGA asserted that the proposed requirements deviate from industry standards and that PHMSA did not provide sufficient justification for this departure. Commenters also emphasized the high costs associated with implementing quantitative risk models, which can include the procurement of specialist expertise, development of new datasets, and transition to a GIS or other new database management system.

Kern River requested clarification regarding which elements of § 192.917 need to be included in an operator's risk model and which elements only need to be included in the overall IM plan. They noted that integrity assessment method determinations, repair decisions, P&M measures selection, root cause analyses, and similar pipe studies all play a part in the overall IM plan and have at times overlapping, but also unique, requirements for data gathering, integration, and threat analysis.

AGA and several individual operators expressed concerns that the proposed rule does not provide a timeline for implementing new risk assessment requirements, thereby implying that operators must implement new requirements by the rule's effective date. Multiple operators and industry trade associations requested that operators be permitted to develop their own implementation schedules or provided suggestions for specific implementation schedules. For example, Enterprise Products requested that PHMSA include a 2-year implementation period for operators to incorporate the data integration and risk assessment requirements into their IM programs.

At the GPAC meeting on January 12, 2017, some committee members noted that any revisions to the risk assessment requirements should be deferred until after PHMSA's Pipeline Risk Modeling Work Group issues its pipeline system risk modeling technical document.[19] There was broad support from the committee for the revisions to § 192.917(c) proposed in the NPRM, with members noting the language was consistent with IM principles and was written using a performance-based approach that articulated the functions and purposes of risk assessment without being prescriptive as to the method or process needing to be used. However, some committee members representing the industry expressed concern with the use of the term ''probability'' in the NPRM's proposed revisions to § 192.917(c), which seemed to imply PHMSA intended for operators to be using probabilistic risk assessment techniques.

Following the discussion, the committee voted 11–0 that the proposed provisions for the risk assessment requirements were technically feasible, reasonable, cost-effective, and practicable if PHMSA modified the proposed rule to restore the reference to ASME/ANSI B31.8S, section 5, to clarify that other methods besides probabilistic techniques may be used; change the term ''probability'' to ''likelihood'' and delete the term ''risk factors'' from § 192.917 (c)(2); and provide a 3-year phase-in period for risk assessments to meet the functional objectives specified in § 192.917(c).

3. PHMSA Response

On March 6, 2020, PHMSA published the final report titled ''Pipeline Risk Modeling—Overview of Methods and Tools for Improved Implementation'' from the joint PHMSA/industry working group on risk modeling.[20] However, PHMSA notes that the report is focused exclusively on the models employed and ''best practices'' for using them. The working group did not address other aspects of the proposed rule, including how a risk assessment is used.

PHMSA believes that the revisions to § 192.917(c) are important to include in this rulemaking now, as many operators have not substantially improved their risk assessment techniques or models since the early initial efforts to prioritize baseline assessment plans in 2004, with the findings from the PG&E incident being a prime, national example. Therefore, PHMSA is establishing explicit minimum standards for the functional requirements of a risk assessment to help assure that operators will achieve this specific aspect of a ''more detailed and comprehensive'' program as discussed in the 2003 IM rule.

In the NPRM's proposed revisions to § 192.917(c), when PHMSA used terms such as ''probability'' and ''risk factors,'' it was not intended to imply that an operator must perform probabilistic risk analysis. To address this, PHMSA has modified the rule language to replace the term ''probability'' with ''likelihood'' and restored the reference to ASME/ANSI B31.8S, section 5, for acceptable risk assessment methodologies as recommended by the GPAC. Similarly, and as also recommended by the GPAC, PHMSA has deleted the phrase ''or risk factors'' from paragraph § 192.917(c)(2) for clarity. Whichever risk assessment methodology an operator chooses, the result must meet the functional requirements and accomplish the purposes specified in this final rule.

PHMSA notes that all data elements specified in § 192.917(b) are important for a robust risk assessment. While operators do have the discretion to expand their data collection efforts, this minimum defined data set is required to be used. As was emphasized by multiple operators in their comments, each pipeline system is susceptible to different threats, and the individual operator is best suited to determine these threats. However, an operator needs the specified data elements to identify threats objectively. As noted in the previous section, PHMSA has modified the rule to refer to the ''pertinent'' data elements, including information derived from O&M activities that assure safe operation and pipeline integrity. This revision clarifies that data elements that are not pertinent for a given pipeline segment need not be included in a risk assessment.

Pertaining to comments regarding the validity of the method used, an operator must ensure the soundness of the risk modelling method they are using applicable to the threats to a given pipeline segment, including its specific leak or failure history. To Kern River's comment as to which elements of § 192.917 need to be included in an operator's risk model and which elements need to be included in an operator's IM plan, PHMSA will note that integrity assessment method determinations, repair decisions, P&M measure selection, and root cause analyses are examples of items that could be included in an operator's risk model based on the particular types of threats being assessed. The existing regulations state that a ''particular threat'' is an identified threat being assessed for each covered segment.

As discussed above, some commenters claimed there would be high costs associated with implementing quantitative risk models, which might include the procurement of specialist expertise, the development of new data sets, and a transition to a GIS or other new database management system. PHMSA notes that operators can use the same data they have been, and are currently, collecting when implementing a quantitative risk model. Operators do not necessarily have to ''recollect'' or otherwise change their existing data to use a probabilistic risk model.

Given the state of some operators' risk assessment programs, PHMSA is persuaded that it is reasonable to allow operators a reasonable amount of time to upgrade their risk assessment models, methodologies, and analyses. However, this is an important provision that operators need to implement as soon as practicable. Therefore, and to be more consistent with the implementation for the data attributes discussed earlier, PHMSA is modifying this final rule to allow an 18-month implementation period for this provision.

A. IM Clarifications—§§ 192.917(a)–(d), 192.935(a)

iii. Threat Assessment for Plastic Pipe—§ 192.917(d)

1. Summary of PHMSA's Proposal

PHMSA proposed to add to the regulations examples of threats unique to plastic pipe that operators must consider, such as poor joint fusion practices, pipe with poor slow crack

[19] For more information on the work group and its efforts, see *https://www.phmsa.dot.gov/pipeline/risk-modeling-work-group/risk-modeling-work-group-overview.*

[20] *https://www.phmsa.dot.gov/news/now-available-phmsa-report-pipeline-risk-modeling-overview-methods-and-tools-improved-0.*

growth (SCG) resistance, brittle pipe, circumferential cracking, hydrocarbon softening of the pipe, internal and external loads, longitudinal or lateral loads, proximity to elevated heat sources, and point loading. The proposed revisions would not otherwise change the current requirements of § 192.917(d).

2. Summary of Public Comment

PHMSA did not receive any public comments on this section. At the GPAC meeting on June 7, 2017, PHMSA noted in its presentation to the committee that there were no public comments on the issue. Subsequently, the GPAC voted 11–0 that the proposed changes to the provisions for IM clarifications for threat assessments for plastic pipe were technically feasible, reasonable, cost-effective, and practicable, and they did not recommend any additional changes to § 192.917(d).

3. PHMSA Response

Since PHMSA did not receive any public comments or additional GPAC recommendations regarding threat assessment for plastic pipe, the final rule includes the requirement in § 192.917(d) as proposed in the NPRM. PHMSA proposed these changes to highlight these potential threats to both operators and inspectors, and finalizing these requirements will provide additional safety and enforcement awareness.

A. IM Clarifications—§§ 192.917(a)–(d), 192.935(a)

iv. Preventive and Mitigative Measures—§ 192.935(a)

1. Summary of PHMSA's Proposal

PHMSA's inspection experience shows that some operators do not implement additional P&M measures based on the evaluation required at § 192.935(a). PHMSA believes that strengthening requirements related to operators' use of insights gained from their IM programs is prudent to ensure effective risk management. Therefore, PHMSA proposed to clarify the expectation that operators use knowledge from risk assessments to establish and implement adequate P&M measures and provided more explicit examples of the types of P&M measures for operators to evaluate.

2. Summary of Public Comment

Several commenters requested that PHMSA revise the requirements at § 192.935(a) to remove the requirement for operators to perform all the listed measures to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in an HCA. These commenters stated that requiring operators to perform all the measures listed at § 192.935(a) negates the need for a risk analysis, as the rule would then require that operators perform each of the listed actions regardless of whether conditions warrant these actions or whether past efforts have been taken. INGAA suggested that PHMSA should keep the existing language, which states that an operator must base the additional measures on the threats the operator has identified to each pipeline segment. GPAC members representing the industry echoed INGAA's claims during the committee meetings.

During the GPAC meeting on June 7, 2017, the GPAC noted that PHMSA's proposed changes removed a statement that an operator must base additional P&M measures on the threats an operator has identified for each pipeline segment. The proposed text, the members believed, implied an operator would be required to evaluate and implement each listed P&M measure every time. Based on PHMSA's webinars and other discussions, the committee members didn't believe that was PHMSA's intent.

Following that discussion, the committee voted 11–0 that the proposed provisions for strengthening the requirements for applying IM knowledge were technically feasible, reasonable, cost-effective, and practicable if PHMSA clarified it was not the agency's intent to require that all listed P&M measures be implemented, and that operators ''must consider'' the listed items.

3. PHMSA Response

PHMSA agrees that all listed measures are not mandatory for implementation in all cases. Requiring an operator to implement P&M measures against threats that might not be applicable to their particular system could be overly burdensome. However, PHMSA has determined that requiring operators to consider the listed measures in their risk analyses and apply them to threats as appropriate is a practical requirement. As recommended by the GPAC, the final rule has been modified to reflect that position; each operator will be required to consider the listed measures and determine the appropriateness of each for their system.

B. Management of Change—§§ 192.13 & 192.911

1. Summary of PHMSA's Proposal

Section 192.911(k) requires that an operator's IM program include a MOC process as outlined in ASME/ANSI B31.8S, section 11. That document guides operators to develop formal MOC procedures to identify and consider the impact of major and minor changes to pipeline systems and their integrity. These changes can include technical, physical, procedural, and organizational changes, and they can be either temporary or permanent changes. Per ASME/ANSI B31.8S, section 11, an operator's MOC process should include the reason for the change, the authority for approving changes, an analysis of the implications of the change, the proper acquisition of the necessary work permits, appropriate documentation, communications of the change to any affected parties, time limitations of the change, and the qualification of staff. The document notes that changes to a pipeline system might require changes to an operator's IM program; similarly, changes to an IM program might also cause changes to a pipeline system. If changes in land use (*e.g.,* increased population) would affect the potential consequence of an incident or the likelihood of an incident occurring, such a change should be reflected in an operator's IM program. The operator should also reevaluate threats accordingly. In short, the MOC process outlined by ASME/ANSI B31.8S helps to ensure that an operator's IM process remains viable and effective as changes to pipeline systems occur or new data becomes available.

Inadequately reviewed or documented design, construction, maintenance, or operational changes can contribute to pipeline failures. In the PG&E incident, the NTSB investigation determined that a substandard piece of pipe was substituted in the field without proper authorization, design review, or approval. PHMSA has subsequently determined that more specific attributes of the MOC process should be explicitly codified within the text of §§ 192.13 (general requirements) and 192.911(k) (IM requirements). As a result, PHMSA proposed to require that operators have a MOC process that includes the reasons for the change; the authority for approving changes; an analysis of implications; the acquisition of required work permits; and evidence documenting communication of the change to affected parties, time limitations, and the qualification of staff.

2. Summary of Public Comment

Public interest groups, such as the PST, and the National Association of Pipeline Safety Representatives (NAPSR) agreed with and supported the proposed MOC provisions, stating that these provisions would enhance pipeline safety. Several individual pipeline operators and trade associations opposed the proposed MOC provisions, stating that the provisions are generally too broad and would be applied to many routine activities that already have established procedures. More specifically, AGA stated that they would create a new requirement for each transmission operator to have a formal MOC process to document and evaluate all changes to pipelines and processes. They further stated that the proposed revisions are unnecessary due to current industry progress related to MOC and the voluntary adoption of industry consensus standards.

Several commenters opposed the proposed addition of four types of changes (design, environmental, operational, and maintenance), asserting that these elements are not included in current industry standards or recommended practices. Similarly, INGAA asserted that PHMSA should eliminate the changes it proposed to § 192.13 that go beyond the recommendations of ASME/ANSI B31.8S. These commenters stated that PHMSA significantly underestimated the impact and burden caused by codifying and expanding the scope of MOC.

Several commenters, including AGA, API, and INGAA, opposed the proposed immediate implementation of the MOC provisions, with some commenters requesting an implementation period of 1 to 5 years. These commenters stated that the proposed changes were significant and would need to be incorporated into existing MOC processes, and that additional time would be needed to complete this in an effective manner. Many commenters also expressed concern over the retroactive application of the proposed MOC provisions.

At the GPAC meeting on January 12, 2017, the committee voted 8—2 that the proposed MOC revisions were technically feasible, reasonable, cost-effective, and practicable if PHMSA provided a 2-year phase-in period for the regulations as they pertain to non-IM pipeline assets, provided a notification procedure for justified extensions, clarified the requirements only covers significant changes that affect safety and the environment, and clearly stated that the revisions do not apply to distribution or gathering lines. The dissenters in the vote (representatives from the Environmental Defense Fund (EDF) and PST) were members representing the public, who thought that the proposed revisions were acceptable as proposed in the NPRM, the phase-in period recommended by the majority of the GPAC was too long, and that there was no reason that the proposed revisions should not apply to gathering lines.

3. PHMSA Response

PHMSA believes that an operator must understand the impacts that their decisions have on safety and the environment. Therefore, PHMSA believes that specifying the types of changes that must be addressed under a MOC program is appropriate. PHMSA also believes that the proposed changes to the MOC provisions conform with the requirements and intent of ASME/ANSI B31.8S.

However, based on the comments received and GPAC recommendations, PHMSA is persuaded that, as published in the NPRM, the language of proposed § 192.13(d) could be overly broad. Therefore, PHMSA has revised the requirement to specify the requirement applies to a ''significant change that poses a risk to safety or the environment'' to limit the application of this requirement to significant changes, as the GPAC recommended. Additionally, and as also recommended by the GPAC, PHMSA is specifying that § 192.13(d) is not retroactive and applies only to onshore transmission pipelines (*i.e.,* not gathering or distribution pipelines).[21]

PHMSA agrees that operators should be afforded time to comply with this new requirement, but also believes that operators can apply this process to non-HCA assets more promptly than the period that the GPAC recommended. Therefore, operators have 18 months for the MOC process to be fully incorporated for non-HCA pipeline segments. PHMSA is also including a notification procedure in accordance with § 192.18 for operators to apply for an extension, of up to 1 year, of the compliance deadline. PHMSA believes including this compliance deadline strikes a balance between the GPAC recommendation and the implementation of a procedure that operators already have in place for HCA pipeline segments, and including a notification procedure to provide operators with more time, if necessary, effectively implements the GPAC recommendations.

C. Corrosion Control—§§ 192.319, 192.461, 192.465, 192.473, 192.478, and 192.935 and Appendix D

i. Applicability

1. Summary of PHMSA's Proposal

Incidents attributed to corrosion continue to occur, which demonstrates that the current requirements can be more effective at preventing incidents caused by certain types of corrosion. This includes compromised pipe or pipe coating caused by damage from construction, cathodic protection deficiencies, interference currents, and internal corrosion. As a result, PHMSA proposed several changes to the regulations for corrosion control, including new requirements for pipe coating assessments, protective coating strength, P&M measures, and additional mitigation of stray current (also referred to as interference current). PHMSA also proposed changes regarding gas stream monitoring program requirements to mitigate internal corrosion. These proposed revisions were made in §§ 192.319, 192.461, 192.465, 192.473, and 192.935(f) and (g) and are discussed more thoroughly in this section. PHMSA also proposed to add a new § 192.478 for the monitoring and mitigation of internal corrosion.

2. Summary of Public Comment

The Coalition to Reroute Nexus, the Michigan Coalition to Protect Public Rights-of-Way, NAPSR, and the PST supported the proposed changes regarding corrosion control and pipeline condition monitoring. Earthworks suggested that PHMSA issue even more stringent requirements given the number of post-Carlsbad incidents that have occurred due to corrosion.[22] The Pipeline Safety Coalition, the Public Service Commission of West Virginia, and the Pennsylvania Public Utility

[21] PHMSA stated, in response to written comments submitted in the docket and discussion during the January 2017 GPAC meeting, that it would in the final rule limit application of the NPRM's proposed management of change amendments at § 192.13(d) to exclude gas distribution and gathering lines. PHMSA notes, however, that (1) PHMSA has undertaken a rulemaking (under RIN 2137–AF53) that will consider extending those or similar requirements to gas distribution pipelines as required by a mandate in section 204 of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (Pub. L. 116–260)); and (2) PHMSA may consider extending those or similar requirements to gas gathering lines as PHMSA obtains more information on the safety risks of such pursuant to enhanced reporting requirements codified by PHMSA's Gas Gathering Final Rule.

[22] An incident near Carlsbad, NM, on August 19, 2000, which was caused due to corrosion, killed 12 people and caused nearly $1 million in damage. The incident was a catalyst for PHMSA's IM program requirements for pipelines.

Commission stated that not all gathering pipelines should be exempt from corrosion monitoring.

Some commenters requested clarification regarding whether the proposed provisions were intended to include transmission, distribution, and gathering pipelines. Other commenters provided input on whether gathering pipelines should be included in the corrosion control requirements, especially alternating current voltage gradient (ACVG) and direct current voltage gradient (DCVG) inspections in proposed § 192.461.

During the meeting on June 7, 2017, GPAC committee members questioned whether the corrosion control requirements would apply to gathering lines—the presumption among the majority of the members was that the requirements were not intended to include gathering or distribution lines. The committee provided other feedback specific to the applicability and implementation of specific corrosion topic areas, which are discussed in the applicable sections below.

3. PHMSA Response

PHMSA has considered the comments received regarding the applicability of the proposed corrosion control requirements. PHMSA stated at the June 2017 GPAC meetings, in response to comments received on the NPRM and the discussions during the GPAC meeting, that it would in the final rule exclude gathering and distribution pipelines from the NPRM's proposed requirements in subpart I related to corrosion control. Accordingly, PHMSA has revised § 192.9 to exempt gathering lines from several of these requirements. PHMSA, however, may consider expanding this provision to gathering lines in the future. Comments on the specific provisions proposed for corrosion control are addressed in the following sections.

As to commenters requesting the regulations be made even more strict than proposed, PHMSA notes that changes more stringent than those proposed would require further notice. PHMSA believes that currently, there is also not sufficient data to justify more stringent changes. PHMSA will continue to review all data sources on the subject, including incident and annual reports, and consider more stringent corrosion control safety requirements in a future rulemaking if there is data supporting the need.

C. Corrosion Control—§§ 192.319, 192.461, 192.465, 192.473, 192.478, and 192.935 and Appendix D

ii. Installation of Pipe in the Ditch and Coating Surveys—§§ 192.319 and 192.461

1. Summary of PHMSA's Proposal

Section 192.319 prescribes requirements for installing pipe in a ditch, including requirements to protect pipe coating from damage during the process. While most operators perform the required high-voltage holiday detection [23] on the pipeline prior to it being placed into the ditch, pipe coating can sometimes be damaged during the handling, lowering, and backfilling process, which can compromise its ability to prevent external corrosion. To address this problem, PHMSA proposed to require that onshore gas transmission pipeline operators perform an above-ground indirect assessment through an ACVG or DCVG survey to identify locations of suspected damage promptly after an operator completes the backfilling process. Per the proposal, operators would remediate any moderate or severe coating damage issues identified by such an assessment, which, was defined as where there are voltage drops of greater than 35 percent for DCVG or 50 dBμV for ACVG.

Section 192.461 prescribes requirements for protective coating systems. PHMSA notes that pipe coating can disbond [24] from the pipe and shield the pipe from CP. The NTSB determined that this was a significant contributing factor in the major crude oil spill that occurred near Marshall, MI, in 2010. As a result, PHMSA determined that additional requirements are needed to specify that coating should not impede cathodic protection. Further, and as discussed above, PHMSA determined that additional requirements are needed so that operators verify that pipeline coating systems for protection against external corrosion have not become compromised or damaged during the installation and backfill process performed during maintenance, repairs, or pipe replacement.[25]

In the NPRM, PHMSA proposed to revise § 192.461(a) to require that pipelines have sufficient coating to protect against damage from being handled. PHMSA also proposed to add § 192.461(f) to require operators to perform an above-ground coating survey within 3 months of placing the pipeline into service and require operators to repair moderate or severe coating damage within 6 months of the assessment.

2. Summary of Public Comment

Stakeholders representing the public, including NAPSR and the PST, generally agreed with and supported the revisions to this section, stating that such requirements would increase safety and were a good step towards reducing the number of incidents that occur due to corrosion. Many commenters stated that ACVG/DCVG surveys are not always feasible and that PHMSA should not limit the tools for performing coating surveys to the two types specified in §§ 192.319 and 192.461(f). For example, INGAA stated that PHMSA did not provide justification for requiring coating surveys, such as ACVG and DCVG, to be used to detect coating issues after construction or after performing a repair or replacement. INGAA further stated that PHMSA should allow operators to use other assessment technologies, such as close interval surveys (CIS) and high-resolution geometry ILI inspection tools, to detect and manage post-construction, post-repair, and post-replacement conditions that contribute to external corrosion.

AGA and AGL Resources (now Southern Company Gas) commented that depth of cover and excessive pavement can make indirect surveys impossible. Further, AGA stated that while conducting post-construction surveys is industry best practice, activities that are not always feasible for operators to complete should not be codified within the regulations.

NACE expressed concern that ACVG and DCVG surveys do not address the stated goal of identifying coatings that impede cathodic protection and objected to setting specific thresholds for these tests. Similarly, INGAA stated that if the requirements for operators to perform coating surveys using ACVG and DCVG are finalized, the proposed voltage drop threshold value in § 192.461(f) should be eliminated.

Industry commenters also stated objections or suggested limitations to the timeframe proposed in § 192.461(f) regarding when these surveys should be performed, stating that the 3-month timeline is inconsistent with the 1-year period allowed to install cathodic protection after the construction of a

[23] "Holidays" are essentially holes or gaps in the coating film that exposes the pipeline to corrosion. The inspections of pipeline coating through electronic defect detectors is commonly also referred to as "jeeping."

[24] Disbonding is the failure of a coating to adhere to the underlying substance to which it was applied. Specific to pipelines, it is a loss of adhesion between the cathodic coating and the pipe due to a corrosive reaction taking place.

[25] This is similar to a proposal in § 192.319 for new construction.

pipeline in existing § 192.455(a)(2). New Jersey Natural Gas expressed concern that 3 months may not be adequate both to procure qualified personnel and to perform these surveys and have a fully mature cathodic protection system to perform a successful coating assessment. NAPSR believed that, unless there was a technical reason for the 3-month deadline for the surveys, the timeline might be too conservative due to service procurement and seasonal conditions. Therefore, they recommended extending the assessment deadline.

API and Enterprise Products commented that PHMSA does not provide any supporting evidence that backfilling a ditch for an onshore transmission pipeline is, or has been, an issue meriting the need for ACVG or DCVG surveys to assess coating integrity. Further, API and Southern California Gas Company stated that § 192.319(a) already requires all operators of transmission gas pipelines to ''protect the pipe coating from damage,'' either in initial installation, or any time the pipe is exposed and backfill material is added. Therefore, the proposed provisions may be duplicative with § 192.461.

At the GPAC meeting on June 6 and 7, 2017, committee members representing the industry echoed many of the comments received, noting also that ACVG and DCVG surveys may not address issues related to coatings impeding CP. Additionally, some of these members noted that coating surveys are not always feasible, and that PHMSA should not limit the tools for performing such surveys. Further, several GPAC members representing the industry suggested that PHMSA should not set specific repair thresholds in the regulations, and that the provisions do not align with current NACE standards.[26] Certain committee members also recommended applying a greater-than-1000-feet standard for this provision, which would match a proposed requirement for external corrosion control under § 192.461 and thought that the timeline for the above-ground coating survey should be extended from 3 months to 1 year to synchronize with current CP installation requirements. The committee also suggested PHMSA clarify the applicability of these provisions is limited to transmission pipelines.

Therefore, the committee voted 10–0 that these provisions proposed at §§ 192.319 and 192.461 were technically feasible, reasonable, cost-effective, and practicable if PHMSA: (1) raised the repair threshold from ''moderate'' to ''severe'' indications, (2) modified the requirements to apply to segments greater than 1,000 feet in length to be consistent with other similar corrosion control requirements, (3) extended the assessment and remediation timeframe to 6 months after a pipeline is placed into service and made allowances for delayed permitting, (4) adjusted the recordkeeping requirements so that operators would be required to make and retain for the life of the pipeline records documenting indirect assessment findings and remedial actions, and (5) provided flexibility for the use of alternative technology unless the agency objected.

3. PHMSA Response

Operators have historically assumed that coating is functioning as intended after construction. However, the NTSB report on the Enbridge crude oil accident near Marshall, MI, identified shielded CP due to disbonded coating as being a contributing cause of the failure. Whenever an operator backfills a pipeline, there is the potential for coating damage. PHMSA believes that conducting coating surveys after backfill is a reasonable and reliable way for operators to identify coating damage inflicted during the construction process before significant corrosion occurs. This is a means for an operator to confirm, after pipeline construction or replacement, that the pipe coating is not compromised and is functioning as intended.

PHMSA believes that ACVG/DCVG surveys are currently the best and most reliable means of detecting coating damage following construction, as opposed to a CIS survey, which is a complementary survey employed to assess the performance of CP systems. However, PHMSA desires to promote the development of new technologies and methods and acknowledges that other technology could be used for performing coating assessments. Therefore, in this final rule, PHMSA is allowing an operator to notify PHMSA of the intent to use other technology, which it may use unless an objection is received, as was recommended by the GPAC. PHMSA's review of such notification would evaluate whether an operator has demonstrated that the ''other technology'' provides equivalent protection to public safety and the environment compared the existing technologies contemplated by this final rule. As a part of its evaluation, PHMSA considers whether there are technical papers from standard developing organizations that support the use of the new technology, as well as any research that has been conducted on that technology and any usage of the technology in other industries and non-regulated pipelines.

PHMSA disagrees that the voltage drop threshold value used as the remediation criterion should be eliminated from the regulation but does agree that the values in the proposed revisions to §§ 192.319 and 192.461 in the NPRM were conservative as they would indicate ''moderate'' coating damage. Therefore, in this final rule and as recommended by the GPAC, PHMSA is specifying the voltage drop threshold value associated with a ''severe'' indication of coating damage as recommended by GPAC.

As recommended by the GPAC, PHMSA is persuaded that the 3-month proposed timeline may not be practical in all situations and has modified the final rule to allow operators up to 6 months after the pipeline is placed into service to complete the necessary assessments and remediation (with allowance for time required to obtain permits, if required). PHMSA has also included a requirement for the associated recordkeeping requirements of these provisions that includes the editorial changes recommended by the GPAC; specifically, that operators must make and retain for the life of the pipeline records documenting the indirect assessment findings and remedial actions.

PHMSA also modified both sections to apply to segments greater than 1,000 feet in length to be consistent with other corrosion control requirements that were similarly altered in this final rule. PHMSA notes that the application of these requirements to segments greater than 1,000 feet in length is also consistent with conditions that have been applied in several special permit applications.

As a part of the requirements for these sections, PHMSA has provided in the regulatory text that the applicable coating surveys must be conducted, except in locations where effective coating surveys are precluded by geographical, technical, or safety reasons.[27] These might include crossings of major interstates or rivers. An operator must document, in accordance with a technically proven

[26] When the ANPRM was being developed, NACE did have standards for ACVG/DCVG surveys. Since the development of this final rule, NACE has subsequently revised those standards, and there is no longer a standard for these surveys.

[27] For example, coating surveys could require drilling holes in roadways, or digging up pipe—each of which entail their own risks to public safety and the environment. Some of the pipelines that would be surveyed could either be cased or have thick-walls, further complicating efforts to conduct coating surveys.

analysis, any decision made not to perform such a coating survey.

As noted before, PHMSA did not intend for these provisions to apply to gathering or distribution pipelines, and it has clarified the applicability of these provisions to transmission lines only. However, PHMSA may expand the application of these provisions in a future rulemaking.

C. Corrosion Control—§§ 192.319, 192.461, 192.465, 192.473, 192.478, and 192.935 and Appendix D

iii. Interference Surveys—§ 192.473

1. Summary of PHMSA's Proposal

Interference currents occur when metallic structures pick up a stray electrical current from elsewhere and discharge the current, thereby causing corrosion. These currents can negate the effectiveness of cathodic protection systems. The sources of stray current problems are commonplace; they can result from other underground facilities, such as the cathodic protection systems from crossing or parallel pipelines, light rail systems, commuter train systems, high-voltage alternating current (HVAC) electrical lines, or other sources of electrical energy in proximity to the pipeline. Stray current corrosion is electrochemical corrosion that occurs when potential differences between a high-conductivity steel pipeline and lower-conductivity environments causes the stray current to flow through the pipe and create a corrosion cell. If stray current or interference issues are not remediated, accelerated corrosion could occur and potentially result in a leak or rupture. Section 192.473 prescribes general requirements to minimize the detrimental effects of interference currents. However, specific requirements to monitor and mitigate detrimental interference currents have not been prescribed in subpart I of part 192. Therefore, in the NPRM, PHMSA proposed to explicitly require operators to conduct interference surveys and remediate adverse conditions in a timely manner. Specifically, PHMSA proposed to amend § 192.473 to require that an operator's program include interference surveys to detect the presence of interference currents and take remedial actions within 6 months of completing the survey. Additionally, PHMSA proposed to require in § 192.473 that operators perform periodic interference surveys whenever needed.

2. Summary of Public Comment

Generally, stakeholders representing the public agreed with and supported the revisions to this section, noting that the requirements, as proposed, could help reduce the number of pipeline incidents caused by corrosion. Numerous trade associations and pipeline companies were concerned about the proposed requirements for interference surveys under § 192.473. Commenters, including Atmos Energy Corporation and AGA, expressed doubt regarding the ability of individual operators to obtain the necessary information from electric transmission providers. APGA and INGAA urged PHMSA to limit this new requirement to specific transmission lines, such as those pipelines subject to the threat of stray electric current. Commenters, including INGAA, also stated that the provisions should allow for the phased-in implementation of remediation measures and provided timeframes from 12 to 18 months. Some commenters suggested a lengthened implementation period for this requirement due to the potential difficulties in obtaining the proper permits.

At the GPAC meeting on June 7, 2017, certain committee members believed that these requirements should apply only to lines that are subject to stray current risks and noted that interference surveys might not be feasible depending on the information operators can obtain from electricity transmission companies. Committee members also suggested a phased-in compliance period between 12 and 18 months for these requirements, and noted, similarly to the proposed external corrosion provisions, that the remediation period did not account for activities like obtaining the necessary permits. There was also extensive discussion at the meeting regarding PHMSA's proposed use of the word ''significant'' in context of the level of corrosion that would need to be remediated, with several committee members suggesting that phrase be tied to a numeric threshold for easier compliance. The committee also discussed, at length, what PHMSA's expectation for a remediation ''plan'' is and what the necessary paper trail would look like for compliance.

After discussion, the committee voted 9–0 that the provisions for external corrosion interference currents are technically feasible, reasonable, cost-effective, and practicable if PHMSA clarified that the surveys are required for lines subject to stray currents and updated the remediation timeframe to require operators create a remediation procedure and apply for necessary permits within 6 months and complete remediation activities within 12 months with allowances for delayed permitting. The committee also specifically recommended that PHMSA clarify that operators must take remedial action when the interference is at a level that could cause significant corrosion as being 100 amps per meter squared, or if it impedes the safe operating pressure of the pipeline, or if it may cause a condition that would adversely affect the environment or the public.

3. PHMSA Response

PHMSA agrees with commenters that every pipeline segment is not equally subject to stray current. Therefore, in this final rule, PHMSA is modifying § 192.473 as recommended by the GPAC to clarify that interference surveys are required when electric potential monitoring indicates a significant increase in stray current, or new potential stray current sources are introduced. Additionally, PHMSA recognizes the need for objective remediation criteria and has included the criteria recommended by the GPAC, specifically ''greater than or equal to 100 amps per meter squared or if it impedes the safe operation of a pipeline or may cause a condition that would adversely impact the environment or the public.'' PHMSA has also revised this final rule to establish a remediation timeframe of 15 months, with allowance for delayed permitting, as recommended by the GPAC.

C. Corrosion Control—§§ 192.319, 192.461, 192.465, 192.473, 192.478, and 192.935 and Appendix D

iv. Internal Corrosion—§ 192.478

1. Summary of PHMSA's Proposal

Section 192.477 prescribes requirements to monitor internal corrosion by coupon testing or other means if corrosive gas is being transported. However, the regulation is silent on standards for determining whether corrosive gas is being transported or regarding any changes occurring that could introduce corrosive contaminants in the gas stream. The existing regulations also do not prescribe that operators continually or periodically monitor the gas stream for the introduction of corrosive constituents through system changes, changing gas supply, abnormal conditions, or other changes. This could result in pipelines that are not monitored for internal corrosion because an initial assessment did not identify the presence of corrosive gas.

As such, PHMSA determined that additional requirements are needed to ensure that operators effectively monitor gas stream quality to identify if and when corrosive gas is being transported and to mitigate deleterious gas stream constituents such as contaminants or liquids. In the NPRM, PHMSA proposed to add a new § 192.478 to require onshore gas transmission pipeline operators monitor for deleterious gas stream constituents and evaluate gas monitoring data quarterly. The proposed § 192.478 would also add a requirement for onshore gas transmission pipeline operators to review their internal corrosion monitoring and mitigation program semi-annually and adjust the program as necessary to mitigate the presence of deleterious gas stream constituents. These requirements would be in addition to the existing requirements to check coupons or perform other measures to monitor for the presence of internal corrosion when transporting a known corrosive gas.

2. Summary of Public Comment

NAPSR generally agreed with and supported the addition of this section. They did note, however, that PHMSA should consider the applicability of these requirements to pipelines that are transporting dry, tariff-quality gas. The PST noted that these proposed requirements in this section provided an enforceable mechanism to hold operators accountable for future incidents caused by internal corrosion.

Multiple commenters considered the proposed changes to requirements for internal corrosion control in § 192.478 to be overly prescriptive, particularly regarding gas monitoring and the list of corrosive constituents. INGAA stated that transmission operators are already taking comprehensive steps to address internal corrosion under subparts I and O of part 192 and that proposed § 192.478 should be eliminated for this reason. Atmos Energy Corporation and INGAA asserted that the internal corrosion monitoring timeline proposed in § 192.478(d) is unreasonable and too frequent, particularly for pipeline systems that are not susceptible to internal corrosion. They further stated that mitigation of internal corrosion is necessary only if a pipeline is transporting, or has the potential to transport, corrosive gas. At the GPAC meeting on June 6, 2017, committee members representing the industry supported those comments made by Atmos Energy Corporation and INGAA.

Commenters at the GPAC meeting, including committee members, noted that some distribution operators rely on upstream transmission pipeline gas suppliers to monitor gas quality and do not own any gas monitoring equipment. A committee member noted that if pipeline operators are getting gas from native sources, gathering lines, or underground storage fields, it might be necessary to determine the quality of the gas. Another committee member noted that there are tariffs that prevent certain quantities of constituents that could be internally corrosive from entering a transmission system. That commenter also noted that operators continually monitor for internal corrosion on pipelines transporting tariff-quality gas as a part of IM.

GPAC members also noted that PHMSA should consider harmonizing these requirements with the existing corrosion control monitoring requirements, as they appeared to be duplicative in certain areas.

After discussing the provisions, the committee voted 10–0 that the proposed provisions related to internal corrosion were technically feasible, reasonable, cost-effective, and practicable if PHMSA limited the applicability of the requirements to those pipelines that are transporting corrosive gas and provided additional guidance based on the committee discussion; changed the reference from the use of ''gas-quality monitoring equipment'' to ''gas-quality monitoring methods;'' specified types of technologies operators can use to mitigate potentially corrosive gas streams; and changed the frequency of the monitoring and program review requirements from twice per year to once per calendar year, not to exceed 15 months. The committee also specifically recommended deleting language that was duplicative to existing requirements and instead recommended PHMSA cross-reference those existing requirements in this section.

3. PHMSA Response

PHMSA noted during the GPAC meeting, that, in its experience, transmission pipeline operators measure the quality of the gas coming into their transmission systems. Based on the quality of the gas, transmission pipeline operators are paying suppliers for the gas they receive or are receiving money for the gas they deliver. Therefore, PHMSA assumes transmission pipeline operators have monitoring systems for the quality of the gas entering their systems. PHMSA's intent with the proposed revision of this section was to help ensure that operators were getting that data to the necessary people in their organization. For instance, if an organization's accountants are getting gas quality data due to their work with tariffs, the personnel responsible for operations and integrity management should get that data.

Based on the comments received, PHMSA is revising the scope of proposed § 192.478 in this final rule to limit its applicability to the transportation of corrosive gas and is modifying the proposed language in paragraph (b)(1) to specify that operators perform monitoring at points where gas with potentially corrosive contaminants enters the pipeline. To address concerns regarding the monitoring frequency, PHMSA is changing the requirement from twice per year to once per calendar year, not to exceed 15 months. Making such a change is more consistent with the timeframes for similar requirements in the regulations as revised by this rulemaking and implements the recommendation made by the GPAC.

Further, to harmonize this rule with other rule requirements, PHMSA is deleting proposed paragraph (c), since § 192.477 currently requires the monitoring of internal corrosion. To address comments regarding technology, PHMSA revised paragraph (b)(2) to read ''Technology to mitigate the potentially corrosive gas stream constituents. Such technologies may include product sampling and inhibitor injections.''

There have been instances where operators do transport corrosive gas by pipeline without investigating the possibility of corrosive effect of the gas on its pipeline and taking steps to minimize internal corrosion.[28] This has happened after operators have withdrawn gas from storage facilities (*e.g.,* caverns) where the gas that was injected became corrosive over time because of properties of the storage facilities. Therefore, there can be scenarios where corrosive gas can enter a pipeline system even if the gas being delivered into the upstream system is non-corrosive.

C. Corrosion Control—§§ 192.319, 192.461, 192.465, 192.473, 192.478, and 192.935 and Appendix D

v. Cathodic Protection—§ 192.465 & Appendix D

1. Summary of PHMSA's Proposal

Appendix D to part 192, ''Criteria for Cathodic Protection and Determination of Measurements,'' which is referenced in § 192.465(f), specifies requirements for CP of steel, cast iron, and ductile pipelines. Appendix D has not been updated since 1971. The NPRM

[28] In the Matter of Transcontinental Gas Pipe Line Company, LLC, CPF 1–2018–1005, available at *https://primis.phmsa.dot.gov/comm/reports/enforce/documents/120181005/120181005_Final%20Order_06192019.pdf* (last visited March 27, 2020). On December 12, 2016, Transcontinental Gas Pipe Line Company reported an explosion and fire that severely damaged a portion of one of its facilities and station piping, resulting in an estimated $15 million in damage. The root cause was determined to be internal corrosion caused by salt water produced from a storage field during gas withdrawal.

proposed to update appendix D by eliminating outdated guidance on CP and the interpretation of voltage measurement to better align with current standards and PHMSA's understanding of current industry practice.

Section 192.465 currently prescribes that operators monitor CP and take prompt remedial action to correct deficiencies indicated by the monitoring. The provisions in § 192.465 do not specify the remedial actions required to correct deficiencies and do not define ''prompt.'' To address this gap, the NPRM proposed to amend § 192.465(d) to require that operators must complete remedial action promptly, but no later than the next monitoring interval specified in § 192.465, or within 1 year, whichever is less. Additionally, new paragraph (f) proposed to add requirements for onshore gas transmission pipeline operators to perform CIS if annual test station readings indicate CP is below the level of protection required in subpart I. Unless it is impractical to do so, PHMSA proposed to require that operators complete CIS with the protective current interrupted. Whereas ACVG and DCVG are performed at the time of construction, before electrical current is on the pipe for CP, a CIS requires the pipe to be in the ground with the rectifiers installed. A CIS will discover areas of low current where CP might be weakened and can discover additional construction, operational or environmental damage along the pipeline when performed as a post-construction task. The NPRM's proposed revisions to § 192.465 would also require each operator to take remedial action to correct any deficiencies indicated by the CIS.

2. Summary of Public Comment

NAPSR and the PST generally agreed with and supported the revisions to § 192.465. NAPSR believed that the inclusion of a timeframe for operators to perform CIS and perform subsequent mitigation measures would increase pipeline safety but noted that PHMSA should provide further guidance on the intervals at which operators should perform the surveys. Both PST and NAPSR supported the revisions to appendix D.

Several industry entities commented on the proposed revisions to appendix D to part 192. INGAA stated that the proposed remaining criteria in appendix D for determining the adequacy of cathodic protection are too narrow, and that all industry standards provide for additional methods of assessing voltage drop. These commenters recommended that PHMSA follow the applicable paragraphs of NACE Standard Practice SP0169. Enterprise noted that appendix D should be consistent with § 195.571, which outlines the criteria that hazardous liquid pipeline operators must use when determining the adequacy of cathodic protection.

Commenters stated that the proposed changes to appendix D, as written, would apply to distribution pipelines as well as transmission pipelines and expressed concern that PHMSA has offered neither justification nor an estimate of the impact on distribution systems. These commenters requested that PHMSA clarify that the proposed changes to appendix D apply only to transmission pipelines.

Commenters, including committee members representing the industry during the meeting on June 6, 2017, stated that PHMSA should amend § 192.465 to include a more realistic timeframe for remedial action, specifically noting that the timeframe for remediation does not account for difficulties in obtaining the necessary permits. Additionally, commenters and GPAC committee members stated this provision could lead to unnecessary and costly work, as there are various situations that can produce a low CP reading that do not require CIS for the identification of the root cause. Those commenters stated there are certain conditions that do not require CIS and recommended allowing operators to identify, troubleshoot, and remediate these certain conditions on their own without the need to conduct CIS.

Further, GPAC members representing the industry disagreed with PHMSA's proposed revisions to the appendix D criteria for determining the adequacy of cathodic protection. Like their commentary on other provisions, these committee members also noted that the impact of these changes to distribution pipelines was not justified or analyzed, and therefore, distribution pipelines should be exempt from the proposed requirements.

Following their discussion, the committee voted 10–0 that the provisions related to the CP of steel, cast iron, and ductile pipelines were technically feasible, reasonable, cost-effective, and practicable if PHMSA clarified that the new requirements in § 192.465(d) only apply to gas transmission pipelines and withdrew the proposed revisions to appendix D. The committee also recommended that PHMSA address situations where CIS may not be an effective response by instead requiring operators investigate and mitigate any non-systemic or location-specific causes of corrosion and require CIS if operators need to address systemic causes of corrosion. Additionally, the committee recommended PHMSA address its comments regarding the timeframe by which the proposed provisions would need to be completed by requiring operators make a remedial action plan and apply for any necessary permits within 6 months and finish the remedial action within 1 calendar year, not to exceed 15 months, or as soon as practicable once the operator obtains the necessary permits.

3. PHMSA Response

PHMSA intended that the amendments proposed in the NPRM would apply only to transmission pipelines and has, in this final rule, added the phrase ''onshore gas transmission pipelines'' to § 192.465(d)(1) of to clarify that limitation. PHMSA will consider expanding application beyond onshore gas transmission pipelines in the future. PHMSA believes that modifying the timeline for remediation is appropriate, and therefore, is requiring operators develop a remedial action plan and apply for the necessary permits within 6 months of the inspection, with the completion of remediation activities to be completed prior to the next monitoring interval or within 1 year, not to exceed 15 months. Like the previous section, such a change is consistent with both the GPAC recommendation on the issue and the timeframes for the related regulations in this final rule. PHMSA understands that, in almost all cases where an operator performs an excavation of 1,000 feet or more, that excavation will probably require some permits. An operator should obtain such permits in a manner to allow the performance of coating surveys and any necessary repairs to the coating.

In the NPRM, PHMSA proposed to update appendix D but did not intend to introduce any new requirements. PHMSA agrees with certain commenters that the proposed revisions could have unintended consequences by creating potential tension with analogous cathodic protection evaluation criteria in NACE Standard Practice SP0169 and § 195.571 governing hazardous liquid lines (which section incorporates NACE Standard Practice SP0169 by reference). However, as PHMSA did not propose incorporation by reference of NACE Standard Practice SP0169 in appendix D, PHMSA is withdrawing the proposed changes to appendix D. PHMSA will continue to examine appropriate evaluation criteria for catholic protection of gas transmission pipelines and may pursue future rulemaking on this topic. These changes to the final rule for CP requirements are in accordance with the GPAC recommendations.

C. Corrosion Control—§§ 192.319, 192.461, 192.465, 192.473, 192.478, and 192.935 and Appendix D

vi. P&M Measures—§ 192.935(f) & (g)

1. Summary of PHMSA's Proposal

Currently, the gas transmission IM provisions do not explicitly address additional P&M measures for the threats of external and internal corrosion. For the same reasons that apply to the proposed changes for general corrosion control as discussed above, PHMSA proposed to address these gaps for HCAs. PHMSA determined that additional P&M measures are needed in § 192.935(f) and (g) to assure that public safety is enhanced in HCAs through additional protections from the time-dependent threats of internal and external corrosion. Specifically, PHMSA proposed to add § 192.935(f) and (g), which would require that operators enhance their corrosion control programs in HCAs to provide additional corrosion protections in addition to the proposed standards in subpart I. Under proposed § 192.935(f), operators would be required to enhance their internal corrosion management programs by performing mitigative actions if deleterious gas stream constituents are being transported and through performing semi-annual reviews of their programs.

Regarding the internal corrosion provisions discussed earlier in this document, § 192.477 prescribes requirements to monitor internal corrosion by coupon testing or other means if corrosive gas is being transported. However, the existing regulations do not prescribe that operators continually or periodically monitor the gas stream for the introduction of corrosive constituents through system changes, changing gas supply, abnormal conditions, or other changes. This could result in pipelines that are not monitored for internal corrosion because an operator's initial assessment did not identify the presence of corrosive gas. To provide additional protections for HCAs in addition to the standards proposed in subpart I, PHMSA proposed that § 192.935(f) would require operators use specific gas quality monitoring equipment for HCA segments, including but not limited to, a moisture analyzer, chromatograph, samplers for carbon dioxide, and samplers for hydrogen sulfide. The proposed provisions would also require operators sample at a certain frequency, use cleaning pigs to sample accumulated liquids and solids, and use corrosion inhibitors when corrosive constituents are present. PHMSA also proposed the maximum amounts of carbon dioxide, moisture content, and hydrogen sulfide that would require operator action.

Under proposed § 192.935(g), operators would also be required to enhance their external corrosion management programs, including controlling both alternating and direct electrical interference currents, confirming external corrosion control through indirect assessment, and controlling external corrosion through CP.

As described in the discussion on interference surveys above, interference currents can negate the effectiveness of CP systems. Section 192.473 prescribes general requirements to minimize the detrimental effects of interference currents. In the NPRM, PHMSA proposed to amend § 192.473 to require that an operator's corrosion control program include interference surveys to detect the presence of interference currents and require the operator take remedial actions within 6 months of completing the survey. In HCAs, PHMSA proposed additional prescriptive requirements in § 192.935(g) to afford extra protections for HCAs, including a maximum interval of 7 years for an operator to perform interference surveys; more specificity regarding the survey performance, including technical acceptance criteria; and a requirement that pipe-to-soil test stations be located at half-mile intervals within each HCA segment with at least one station in each HCA, if practicable.

Lastly, PHMSA proposed to make conforming edits to appendix E, which provides guidance for P&M measures for HCA segments subject to subpart O. PHMSA proposed to accommodate the proposed revised definition for "electrical survey" by replacing that term with "indirect assessment" to accommodate other techniques in addition to CIS.

2. Summary of Public Comment

NAPSR and the PST agreed with and supported the proposed changes to the P&M measures for addressing internal and external corrosion in HCAs and suggested strengthening the proposed provisions further.

While trade associations and individual operators supported certain aspects of the proposed provisions covering the P&M measures addressing external corrosion and internal corrosion in HCAs, these commenters objected to the specific requirements in § 192.935. Many of these commenters stated a preference for allowing operators the flexibility to implement corrosion control based on their own judgment of the severity of the threat. In general, many industry commenters stated that individual sections of the proposed provisions were too broad and prescriptive, and pipeline operators would incur greater costs without justified benefit. Further, they stated that the monitoring frequency of twice per year was too frequent. Some commenters recommended that PHMSA reference ASME standards for implementing P&M measures, and other commenters stated concern that some of the proposed provisions are not consistent with NACE standards.

Many commenters objected to several of the proposed aspects of internal corrosion control, such as the identification of threats, monitoring, and filtering, and these commenters stated that operators should have flexibility in implementing P&M measures. For example, INGAA opposed the proposed requirement in § 192.935(f) that requires operators to install continuous gas quality monitoring equipment at all points in which gas with potentially deleterious contaminants enters the pipeline. INGAA recommended that § 192.935(f) apply only to pipeline segments with a history of internal corrosion and stated that this would be consistent with the required risk analysis that operators perform to determine whether P&M measures are necessary. Similarly, Atmos Energy recommended that gas sources be monitored only at those sources suspected, in the judgment of the operator, of having deleterious gas stream constituents, and that such monitoring can be performed in real-time or periodically. INGAA stated that PHMSA should modify proposed § 192.935(g) to require that operators conduct periodic indirect inspections only where a pipeline segment has a known history of corrosion.

During the GPAC meeting on June 6, 2017, committee members representing the industry reiterated that § 192.935(f) and (g) were too broad and prescriptive and should not apply to every HCA pipeline segment indiscriminately. These members, echoing comments made by INGAA, stated that operators should use their risk assessments to be used to determine which specific P&M measures are needed in accordance with the current IM approach.

The committee also suggested that PHMSA should reference specific ASME standards for P&M measures and ensure they are consistent with NACE standards. Members representing the public suggested PHMSA review the proposed changes throughout subpart I and ensure that they would be as enforceable as the proposed P&M measures if the P&M measures were to be deleted. Members also discussed the fact that distribution operators do not always have gas monitoring equipment for their lines, as they depend on the suppliers to monitor the gas quality.

Following the discussion, the committee voted 9–1 (with a representative from PST dissenting) that the proposed rule, regarding the provisions for P&M measures for internal and external corrosion, were technically feasible, reasonable, cost-effective, and practicable if PHMSA withdrew the specific provisions discussed in § 192.935(f) and (g) and appendix E, as the requirements would have been duplicative with subpart I.

3. PHMSA Response

PHMSA noted during the GPAC meeting that it was persuaded by commenters that the changes it is making to the general corrosion control requirements in subpart I in this final rule are sufficient and that the additional regulations proposed in § 192.935(f) and (g) and appendix E were duplicative. The proposed changes to subpart I that PHMSA is finalizing in this rulemaking apply to pipelines in both HCAs and non-HCAs, and they were similar to the P&M measures that PHMSA was proposing regarding corrosion control in HCAs specifically. Therefore, PHMSA believes that the changes to subpart I in this rule provide the safety that the proposed changes at § 192.935(f) and (g) intended to provide. The proposed changes to appendix E incorporated the proposed definition for ''electrical survey'' and did not contain further substantive changes. After considering those comments, and as recommended by the GPAC, PHMSA is withdrawing all the proposed changes to § 192.935(f) and (g) and appendix E.

D. Inspections Following Extreme Weather Events—§ 192.613

1. Summary of PHMSA's Proposal

Weather events and natural disasters that can cause river scour, soil subsidence or ground movement may subject pipelines to additional external loads, which could cause a pipeline to fail. These conditions can pose a threat to the integrity of pipeline facilities if those threats are not promptly identified and mitigated. While the existing regulations provide for design standards that consider the load that may be imposed by geological forces, weather events and natural disasters can quickly impact the safe operation of a pipeline and have severe consequences if not mitigated and remediated as quickly as possible.

In the NPRM, PHMSA proposed revising § 192.613 to require that an operator inspect all potentially affected pipeline facilities after an extreme weather event to help ensure that no conditions exist that could adversely affect the safe operation of that pipeline. The operator would be required to 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 inspection required. The NPRM's proposed revisions to § 192.613 also provided that the initial inspection must occur within 72 hours after the cessation of the event, defined as the point in time when the affected area can be safely accessed by available personnel and equipment required to perform the inspection. If an operator finds an adverse condition, the NPRM' s proposed revisions to § 192.613 would require an operator to take appropriate remedial action to ensure the safe operation of a pipeline based on the information obtained because of performing the inspection.

2. Summary of Public Comment

The PST, NAPSR, and EnLink Midstream supported the proposed amendments to § 192.613, with many other stakeholders supporting the intent of the proposed provisions but requesting further clarification on some of the terms used within the proposal.

Some commenters expressed concern with the broad requirements of an ''inspection'' and requested PHMSA clarify what an inspection following an extreme weather event would entail. Additionally, these stakeholders stated that the proposed definition of an extreme weather event was vague and requested clarification. INGAA stated that operators are already required to have procedures to ensure a prompt and effective response to emergency conditions through § 192.615 and suggested that to avoid duplicative regulation, PHMSA should instead modify § 192.615(a)(3) to incorporate additional specificity on weather events that may trigger a response.

Many commenters objected to the proposed timeframe, stating that the 72-hour requirement listed in the rule could be problematic. Commenters stated that PHMSA should allow operators to determine when an impacted area can be safely accessed, and that pipeline operators are best positioned to evaluate the balance between the safety and the need for inspections to ensure continued safe operation of their systems. INGAA stated that the 72-hour requirement should either be replaced with a more general statement such as ''as soon as practicable,'' or that PHMSA should create a process to request an exception to the requirement. Louisiana Mid-Continent Oil and Gas Associations stated that extreme weather events vary significantly by region and commented that not all local geography and extreme weather events are the same. They further stated that the 72-hour deadline for inspection may be too prescriptive depending on the extreme weather event. They stated that because Louisiana is subjected to many unusual extraordinary events, such as spillway openings, high/low river flows, and rainwater flooding, PHMSA should clarify what ''other events'' means and how the cessation of an event is determined.

At the GPAC meeting of January 12, 2017, members noted concerns with the provisions as proposed but voted 12–0 that the provisions were technically feasible, reasonable, cost-effective, and practicable if PHMSA modified the proposed rule to clarify that the timing for this provision is to begin after the operator has made a reasonable determination that the area is safe, clarify in the preamble that operators are encouraged to consult with pipeline safety and public safety officials in order to make such determinations, delete the phrase ''whichever is sooner'' at the end of § 192.613(c)(2), and change the word ''infrastructure'' to ''facilities.''

3. PHMSA Response

PHMSA agrees that an operator's ability to inspect a pipeline facility following an extreme weather event may vary greatly depending on the type of extreme weather event that has taken place and the specific location of the event. The NPRM's proposed revisions to § 192.613 would require operators to inspect its pipeline facilities after the cessation of an extreme weather event. Cessation of the event was defined as the point of time when the affected area could be safely accessed by the personnel and equipment, including availability of personnel and equipment, required to perform the inspection. However, in consideration of the comments received, PHMSA is persuaded that additional clarification is warranted and that 72 hours after the cessation of the event may not be enough time in all cases for operator personnel and equipment to assess and inspect a pipeline safely.

Therefore, as recommended by the GPAC, PHMSA has modified this final rule to require an operator perform an initial inspection 72 hours after the operator reasonably determines that the affected area can be safely accessed by personnel and equipment, and the necessary personnel and equipment required to perform such an inspection are available. PHMSA encourages operators to consult with pipeline and public safety officials, including the appropriate PHMSA regional office, when making these determinations. If an operator is unable to commence the inspection in the 72-hour timeframe due to the unavailability of personnel or equipment, the operator must notify the appropriate PHMSA Region Director as soon as practicable.

If an operator finds an adverse condition, the operator must take appropriate remedial action to ensure the safe operation of a pipeline based on the information obtained from the inspection. Such actions might include, but are not limited to:

- Reducing the operating pressure or shutting down the pipeline;
- Isolating pipelines in affected areas and performing ''stand up'' leak tests;
- Modifying, repairing, or replacing any damaged pipeline facilities;
- Preventing, mitigating, or eliminating any unsafe conditions in the pipeline rights-of-way;
- Performing additional patrols, depth of cover surveys and adding cover over the pipeline, ILI or hydrostatic tests, or other inspections to confirm the condition of the pipeline and identify any imminent threats to the pipeline;
- Implementing emergency response activities with Federal, State, or local personnel; and
- Notifying affected communities of the steps that can be taken to ensure public safety.

PHMSA would not expect operators to comply with these provisions for weather or other disruptive events when, considering the physical characteristics, operating conditions, location, and prior history of the affected system, the event would not be expected to impact the integrity of the pipeline. For example, extreme weather events would not include rain events that do not exceed the high-water banks of the rivers, streams or beaches in proximity to the pipeline; rain events that do not result in a landslide in the area of the pipeline; storms that do not produce winds at tropical storm or hurricane level velocities; or earthquakes that do not cause soil movement in the area of the pipeline.

PHMSA is also modifying § 192.613(c) introductory text and (c)(1) as the GPAC recommended, by removing the phrase ''whichever is sooner'' and replacing the term ''infrastructure'' with ''facilities.'' As discussed during the GPAC meeting, ''pipeline facilities'' is a defined term at § 192.3, and the use of that term will likely provide additional clarity.

E. Strengthening Requirements for Assessment Methods—§§ 192.923(b) & (c), 192.927, 192.929

i. Internal Corrosion Direct Assessment (ICDA)—§§ 192.923(b) & 192.927

1. Summary of PHMSA's Proposal

The current regulations do not specify the quality and effectiveness of ICDA. NACE International submitted a petition for rulemaking on February 11, 2009, requesting that PHMSA address this issue. In the NPRM, PHMSA proposed amendments to §§ 192.923(b) and 192.927 to incorporate by reference NACE SP0206–2006 and further supplement the NACE standard to address issues observed by PHMSA.

For indirect inspections, PHMSA proposed to require that operators use pipeline-specific data, exclusively in performing an indirect inspection, and that the use of assumed pipeline or operational data would be prohibited. PHMSA also proposed operators be required to consider the accuracy, reliability, and uncertainty of data used to make calculations regarding the critical inclination angle of liquid holdup and the inclination profile of pipelines. Further, PHMSA proposed that operators be required to select locations for direct examination and establish the extent of pipe exposure needed, to explicitly account for these uncertainties and their cumulative effect on the precise location of predicted liquid dropout.

For detailed examinations as defined in NACE SP0206–2006, PHMSA proposed to require that operators identify a minimum of two locations for excavation within each covered segment associated with the ICDA Region and perform a detailed examination for internal corrosion at each location using ultrasonic thickness measurements, radiography, or other generally accepted measurement techniques. One required location would be the low point within the covered segment nearest to the beginning of the ICDA Region. The second required location would be near the end of the ICDA Region within the covered segment. If corrosion was found at any location, the operator would be required to evaluate the severity of the defect, expand the detailed examination program to determine all locations that have internal corrosion within the ICDA region, and expand the detailed examination program to evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) with similar characteristics to the ICDA Region in the operator's pipeline system.

For post-assessment evaluation and monitoring, PHMSA proposed to require that operators evaluate the effectiveness of ICDA as an assessment method for addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals than those currently specified in the regulations at § 192.939. PHMSA also proposed to require that operators validate their flow modeling calculations by comparing locations of discovered internal corrosion with locations predicted by the model. Additionally, PHMSA proposed to require that operators continually monitor each ICDA Region that contains a covered segment where internal corrosion was identified and by periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products.

Finally, PHMSA proposed to require that operators include in their plans the criteria used in making key decisions in implementing each stage of the ICDA process and provisions that the analysis be carried out on the entire pipeline in which covered segments are present.

2. Summary of Public Comment

NAPSR expressed its agreement with, and support for, the proposed revisions to §§ 192.923(b) and 192.927. Multiple pipeline operators and industry trade associations commented that the proposed provisions should simply incorporate the NACE standard by reference, and should not exceed those established industry standards, be rigidly prescriptive, or otherwise be mandatory. PG&E, commenting on the incorporation of standards by reference, requested PHMSA replace the phrase ''as required by'' with ''in accordance with'' so that operators can meet the substantial requirement but have flexibility in the implementation of that requirement if the industry publishes new techniques to perform ICDA. NACE International expressed its belief that, as described in NACE SP0206–2006, ICDA is an acceptable standalone methodology for assessing pipeline integrity.

Atmos Energy commented that the proposed mandated monitoring for all ICDA regions would be potentially excessive and recommended that PHMSA delete the proposed language and restore the current language at

§ 192.927(c)(4)(ii).[29] Another commenter recommended that PHMSA remove the proposed notification requirement prior to an operator performing an ICDA, noting that operators currently provide this information as part of other annual reporting.

At the GPAC meeting on December 15, 2017, the GPAC committee voted, 13–0, to revise §§ 192.923(b)(2) and (3) and 192.927 according to the recommendations by PHMSA staff at the meeting, which included supplementing the NACE standard with additional requirements to address specific issues that could adversely affect ICDA results.

3. PHMSA Response

PHMSA believes that it is appropriate to address ICDA by incorporating by reference the NACE standard and supplementing it with additional requirements pertaining to indirect inspections (a step in the NACE standard's ICDA process to help in determining where direct assessments need to be made), detailed examinations, and post-assessments. For indirect inspections, PHMSA has implemented additional requirements regarding the data an operator must use and accounting for uncertainties in that data. Where an indirect inspection demonstrates that detailed examinations are needed, PHMSA is expanding the examinations that an operator must perform to evaluate for the potential for internal corrosion in all pipeline segments if corrosion is found in the ICDA region. Regarding post-assessments, PHMSA is requiring operators to evaluate the effectiveness of ICDA as an assessment method and determine whether a covered segment should be reassessed more frequently than the intervals specified at § 192.939. Additionally, PHMSA is requiring operators validate the flow modelling calculations they use in the ICDA process as well as continually monitor each ICDA region that contains a covered segment where internal corrosion has been identified.

When the first IM regulations were promulgated in the 2003 IM rule, there was no consensus industry standard for ICDA that could be adapted or incorporated into the regulations to promote better pipeline safety regarding internal corrosion. Incorporating by reference the NACE standard into the regulations would improve pipeline safety because the NACE standard (1) typically requires more direct examinations than the current regulatory requirements; (2) encompasses the entire pipeline segment and requires that all inputs and outputs be evaluated; and (3) is considered by many to be an equivalent or superior indirect inspection model compared to the Gas Technology Institute (GTI) model currently referenced in § 192.927. Its range of applicability with respect to operating pressure is greater than the GTI model, thus allowing the use of ICDA in pipelines with lower operating pressures and higher flow velocities.

The existing requirements in § 192.927 have one aspect that has proven problematic: the definition of regions and requirements for selection of direct examination locations in the regulations are tied to the covered segment. A ''covered segment'' is defined in § 192.903 as ''a segment of gas transmission pipeline located in a high consequence area.'' The terms ''gas'' and ''transmission line'' are defined in § 192.3. Therefore, covered segment boundaries are determined by population density and other consequence factors without regard to the orientation of the pipe and the presence of locations at which corrosive agents may be introduced or may collect and where internal corrosion would most likely be detected (*e.g.,* low spots). Section 192.927 requires that locations selected for excavation and detailed examination be within covered segments, meaning that the locations at which internal corrosion would most likely be detected may not be examined. Thus, the existing requirements do not always facilitate the discovery of internal corrosion that could affect covered segments. PHMSA is addressing this problem in this final rule by incorporating NACE SP0206–2006 and by expanding the detailed examination program, whenever internal corrosion is discovered, to determine all locations that have internal corrosion within the ICDA region.

PHMSA believes requiring a notification requirement for operators is important so that PHMSA can review the specific proposal to use a standard to assess pipe segments that are explicitly excluded from the scope of the standard. PHMSA has also revised § 192.927(c) to clarify that an operator must conduct the ICDA process ''in accordance with'' the NACE standard to avoid the implication that all non-mandatory recommendations contained in the standard are required.

E. Strengthening Requirements for Assessment Methods—§§ 192.923(b) & (c), 192.927, 192.929

ii. Stress Corrosion Cracking Direct Assessment (SCCDA)—§§ 192.923 & 192.929

1. Summary of PHMSA's Proposal

The current regulations do not specify a number of issues that affect the quality and effectiveness of SCCDA integrity assessments. Specifically, Appendix A3 of ASME/ANSI B31.8S, which is referenced in the regulations, provides some guidance for conducting SCCDA, but the guidance is limited to stress corrosion cracking (SCC) that occurs in high-pH environments. NACE International submitted a petition for rulemaking to PHMSA on February 11, 2009, requesting that PHMSA address this issue by incorporating by reference NACE SP0204–2008, which addresses near-neutral SCC in addition to high-pH SCC. Accordingly, in the NPRM, PHMSA proposed changes to §§ 192.923 and 192.929 to incorporate by reference NACE SP0204–2008 and supplement the NACE standard to address issues observed by PHMSA in the areas of data gathering and integration, indirect inspection, direct examinations, remediation and mitigation, and post-assessments.

PHMSA proposed to require an operator's SCCDA plan to evaluate the effects of a carbonate-bicarbonate environment; the effects of cyclic loading conditions on the susceptibility and propagation of SCC in both high-pH and near-neutral-pH environments; the effects of variations in applied CP, such as overprotection, CP loss for extended periods, and high negative potentials; the effects of coatings that shield CP when disbonded from the pipe; and other factors that affect the mechanistic properties associated with SCC.

For indirect inspections, PHMSA proposed to require an operator's plan include provisions for conducting at least two above-ground surveys using complementary measurement tools most appropriate for the pipeline segment based on the data gathered.

For direct examinations, PHMSA proposed to require an operator's procedures provide for conducting a minimum of three direct examinations within the SCC segment at locations determined to be the most likely for SCC to occur.

For post-assessments, PHMSA proposed to require that the operator's procedures include the development of a reassessment plan based on the

[29] PHMSA regulations at § 192.927(c)(2) define an ICDA region as a continuous length of pipe (including weld joints), uninterrupted by any significant change in water or flow characteristics, that includes similar physical characteristics or operating history. An ICDA region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur until a new input introduces the possibility of water entering the pipeline.

susceptibility of the operator's pipe to SCC as well as on the mechanistic behavior of identified cracking.

2. Summary of Public Comment

Multiple commenters supported the proposed changes to § 192.929 for SCCDA. NAPSR expressed its agreement with, and support of, these revisions. Spectra Energy Partners (SEP), which merged with Enbridge in 2017, provided comments in support of the proposed inclusion of explicit requirements for SCCDA. SEP expressed its belief that SCCDA is a diligent, practicable approach for assessments for SCC for cases where the pipeline has not previously experienced an in-service failure caused by SCC and provided specific edits to make the proposed requirements for SCCDA clearer and more practicable. A commenter recommended that the requirements for SCCDA specify that an operator is required to conduct assessments in areas that are most likely to be subject to SCC regardless of HCA designation.

Several other commenters questioned or opposed the proposed changes to § 192.929. Several commenters, including API, expressed their support of NACE standards SP0204–2008 for SCCDA but recommended that PHMSA not exceed those established industry standards and should not make the recommendations within those standards mandatory. NACE International stated it was unaware of any conclusive data regarding overprotection or high-negative potentials as a factor in SCC of pipelines, which is what the NPRM's proposed revisions to § 192.929 suggested. Additionally, NACE International commented that PHMSA went beyond the practices stated in NACE Standard SP0204–2008 by proposing to require a minimum of two above-ground surveys and three direct examinations.

INGAA proposed to clarify the way in which SCCDA can be used as an IM method, asserting that SCCDA is a valid method to assess SCC threats in gas pipeline segments that are susceptible to, but have no history of, SCC.

Other commenters provided specific technical comments regarding these proposed provisions. TransCanada asserted that applying the NACE ''significant SCC'' definition as the threshold for immediate repair is both overly conservative and overly complicated, and they suggested that PHMSA instead adopt the threshold of ''noteworthy'' as defined in ASME STP–PT–011.

Enable Midstream Partners (EMP) agreed that operators should consider the specific factors PHMSA proposed in § 192.929(b)(1) and (4) as part of the data gathering and integration and post-assessment remediation and mitigation process for SCCDA. However, EMP asserted that PHMSA should clarify these sections by including a referenced standard that provides guidance to operators on how they should consider these specific factors. Another commenter stated that PHMSA should include a reference to ASME/ANSI B31.8S, Appendix A3, for susceptibility criteria.

Commenters also suggested that PHMSA allow operators to use sound engineering judgments when calculating the remaining strength of the pipeline segment if the segment is subject to the pipeline material properties and attributes verification requirements of § 192.607 and those requirements have not yet been met.

At the GPAC meeting on December 15, 2017, the committee recommended PHMSA revise the approach proposed in the NPRM by making the changes to these provisions that were recommended by PHMSA staff during the meeting, which were to replace the spike hydrostatic pressure test requirements with a reference to § 192.506(e) to eliminate redundancy; address the gap pertaining to failure pressure calculations when data is not available; codify, as applicable, the expectation that the recommendations within the NACE standard are not mandatory; communicate additional guidance as needed during rule implementation; and consider how to structure the rule to apply results from non-HCAs to HCAs.

3. PHMSA Response

When the first IM rule was promulgated in 2003, there was no NACE standard for SCCDA. Additionally, the requirements pertaining to SCC in ASME/ANSI B31.8S, Appendix B, only applied to pipe susceptible to high pH SCC (*i.e.,* pipelines susceptible to near-neutral SCC were not addressed). Therefore, PHMSA believes that incorporating by reference the NACE standard and supplementing it with additional requirements to address issues it has observed related to data gathering and integration, indirect inspection, direct examinations, remediation and mitigation, and post-assessments, is an appropriate way to address SCCDA.

For data gathering and integration, PHMSA is requiring that operators gather and evaluate data related to SCC at all sites an operator excavates while conducting its pipeline operations where the criteria in NACE SP0204–2008 indicate the potential for SCC. Per this final rule, operators must additionally analyze the effects of a carbonate-bicarbonate environment, cyclic loading conditions, variations in applied CP, the effects of coatings that shield CP when disbonded from the pipe, and other factors that would affect the mechanics of SCC. For indirect inspections, PHMSA is requiring operators conduct at least two above-ground surveys using the measurement tools most appropriate for the pipeline segment based on an evaluation of the collected data. An operator's plan for direct examination must include a minimum of three direct examinations within the SCC segment at the locations where SCC would be most likely to occur. If an operator finds any indication of SCC in a segment, an operator must perform specific mitigation measures. Further, in this final rule, an operator must develop procedures for post-assessments based on the susceptibility of the pipeline segment to SCC as well as the mechanical behavior of identified cracking. Regarding EMP's comment stating that PHMSA should provide guidance to operators on how they should consider specific factors as a part of the data gathering and integration process by referring to a standard incorporated by reference within PHMSA regulations, as well as the comment recommending that PHMSA incorporate a reference to ASME/ANSI B31.8S, Appendix A3, for susceptibility criteria, PHMSA declines to incorporate by reference such standards because it could limit operators from considering all of the factors that they should.

PHMSA also agrees with commenters that referring to § 192.506, *Transmission lines: Spike hydrostatic pressure test,* in § 192.929 is preferred instead of repeating the spike hydrostatic test requirements and has changed this final rule accordingly. PHMSA addressed the comment about determining predicted failure pressure when needed data are not available by referencing § 192.712, which explicitly provides an operator with conservative assumptions and alternatives for material toughness values, material strength, and pipe dimensions and other data, in lieu of documented material properties.

F. Repair Criteria—§§ 192.714, 192.933

PHMSA identified several improvements to the IM repair criteria based on its experience gained since the IM rule became effective in 2004; ongoing research and development, including developments in ASME/ANSI B31.8S; and investigations into recent incidents. In the NPRM, PHMSA proposed adjustments to the existing repair criteria for anomalies discovered in HCAs and proposed new repair criteria for anomalies found outside of HCAs.[30]

F. Repair Criteria—§§ 192.714, 192.933

i. Repair Criteria in HCAs—§ 192.933

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to add more immediate repair conditions and more 1-year repair conditions for HCA pipeline segments in § 192.933. The specific anomalies and repair schedules for cracks, dents, and corrosion metal loss are discussed in their respective sections below. In certain cases, like for SCC and selective seam weld corrosion anomalies that were new to the repair criteria, PHMSA proposed to require that operators repair ''any indication of'' such anomalies. In other cases, such as for dents, PHMSA did not make significant changes to the existing repair criteria at § 192.933, which require the repair of ''any indication of'' metal loss, cracking, or a stress riser.

2. Summary of Public Comment

Public advocacy groups, including Pipeline Safety Coalition, the PST, and Clean Water for North Carolina, supported the proposed provisions that would strengthen the existing repair criteria at §§ 192.713 (non-HCAs) and 192.933 (HCAs). Additionally, NAPSR and the NTSB supported PHMSA's proposed repair criteria revisions.

There was common agreement from pipeline operators and the industry trade associations that the processes for HCA repairs and non-HCA repairs should be standardized. However, the trade associations and pipeline operators generally believed that the proposed provisions at §§ 192.713 and 192.933 were too prescriptive and would impede operators from performing repairs based on risks. They further stated that the proposed provisions do not take into consideration other factors that operators currently consider when optimizing plans to remediate anomalies, such as historical data, geography, and congestion of the right-of-way.

Some of the commenters representing the industry recommended PHMSA eliminate all references to the words ''any indication of'' within the proposed revisions to §§ 192.713 and 192.933 when applied to anomalies needing repair so that it is the confirmed presence of a condition that requires a repair instead. These commenters stated that requiring operators to repair an ''indication of'' certain anomalies would cause needless repairs and misallocate resources. Spectra Energy stated that PHMSA's annual report data indicates that only one repair is required for every three anomaly investigations, which demonstrates that the existing anomaly response criteria operators have implemented are appropriately conservative.

3. PHMSA Response

Based on PHMSA's annual report data, the number of immediate repairs have remained relatively constant even though the baseline assessment period has concluded. PHMSA understands that this is likely the result of operators deferring repair of non-immediate conditions until the defect progresses into an immediate repair condition, rather than immediate conditions arising spontaneously. PHMSA understands that most defects that become immediate repair conditions are observable by ILI equipment well in advance of progression to an immediate repair condition. The repair criteria in this final rule are intended to assure that anomalies are repaired before they become an immediate condition and are at or near failure. In this final rule, PHMSA has included reference to ASME/ANSI B31.8S within each of §§ 192.714 and 192.933 to take into consideration other factors that operators currently consider when establishing remediation plans.

In this final rule, PHMSA has removed the proposed repair criteria under §§ 192.714 (non-HCAs) and 192.933 (HCAs) for SCC and selective seam weld corrosion, which were new repair criteria that contained the phrase ''any indication of.'' PHMSA combined SCC and selective seam weld corrosion repair criteria into a more general cracking repair criteria because each of these phenomena is, or results in, cracking. PHMSA included remediation measures for SCC under the requirements at § 192.929, which are the requirements for using direct assessment for SCC but did not require the remediation of ''any indication of'' SCC. PHMSA was not proposing to change any of the existing repair criteria that referenced ''any indication of,'' such as that for dents with any indication of metal loss, cracking, or a stress riser. Those repair criteria remain unchanged in this final rule.

F. Repair Criteria—§§ 192.714, 192.933

ii. Repair Criteria in Non-HCAs—§ 192.714

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed at § 192.713 repair criteria for non-HCA areas to assure that operators promptly repair injurious defects that are discovered outside of HCAs. These proposed repair criteria for non-HCAs were based on, and were similar, to, the repair criteria (regarding structure, anomaly types, and the repair timeframes) for HCA pipeline segments proposed at § 192.933.

For those anomalies for which a 1-year response is required on HCA pipeline segments, PHMSA proposed that a 2-year response would be required in non-HCA pipeline segments. This proposal would require operators to remediate anomalous conditions on gas transmission pipeline segments promptly and commensurate with the risk they present, while allowing operators to allocate their resources to those anomalies in HCAs that present a higher risk.

The specific anomalies and repair schedules for cracks, dents, and corrosion metal loss are discussed in their respective sections below.

2. Summary of Public Comment

Citizen groups, including Pipeline Safety Coalition, the PST, and Clean Water for North Carolina, supported the proposed provisions that would strengthen the repair criteria for HCAs and non-HCAs. Additionally, NAPSR and the NTSB supported PHMSA's revisions to the repair criteria.

Generally, the industry trade associations and pipeline operators supported PHMSA's intention of establishing repair criteria outside of HCAs but disagreed with some of the specific provisions. There was common agreement, however, that the processes for HCA repairs and non-HCA repairs should be standardized.

The trade associations and pipeline operators generally believed that the proposed provisions were too prescriptive and would impede operators from performing repairs based on risks. They further stated that the proposed provisions do not take into consideration other factors that operators currently consider when optimizing plans to remediate anomalies, such as historical data, geography, and congestion of the right-of-way.

AGA recommended that PHMSA create a new subpart to address assessment requirements outside of

[30] The GPAC voted on each section of the repair criteria separately, and each section is discussed in more detail below.

HCAs and add a section within that subpart to cover repair criteria. Several other trade associations and pipeline operators echoed AGA's recommendations.

Several industry commenters also stated that the rulemaking did not demonstrate that the safety benefit of strengthened repair criteria outweighs the costs. Multiple operators stated that the proposed repair provisions in § 192.713 would increase the number of digs operators would need to perform and asserted that the increased number of digs may not improve pipeline safety.

Certain commenters suggested that it would not be appropriate for PHMSA to require operators to repair immediate conditions in non-HCAs before repairing immediate conditions in HCAs, and that PHMSA should require operators to prioritize those conditions discovered within HCAs if operators discover multiple immediate conditions in HCAs and non-HCAs simultaneously. More specifically, AGA requested that the rule explicitly prioritize immediate conditions within HCAs over immediate conditions in other locations when conditions are discovered simultaneously and recommended that PHMSA adopt different terminology for ''immediate repair conditions'' inside and outside HCAs. Similarly, other industry trade organizations expressed concern that the proposed provisions for non-HCAs would complicate the allocation of resources to HCAs on a higher-priority basis when confronted with the large number of new, non-HCA pipelines needing assessments.

Commenters also requested PHMSA make the sections pertaining to non-HCA repairs and HCA repairs consistent regarding pressure reductions. Commenters representing the industry noted that, as proposed, certain notification requirements for long-term pressure reductions or for those operators unable to respond within the given timeframe were different depending on whether the pipeline was in an HCA or a non-HCA. These commenters suggested that those notification procedures be made consistent, wherever possible, between the HCA and non-HCA repair criteria. Multiple trade associations and pipeline industry entities also expressed concerns that the proposed provisions requiring ''an operator to reduce the operating pressure of its affected pipeline until it can remediate the immediate repair conditions'' are unnecessarily conservative. INGAA asserted that the proposed pressure reduction requirements for non-HCAs are more stringent than the pressure reductions requirements for HCAs, and several commenters offered alternative methods for determining appropriate operating pressure reductions. Specifically, these commenters requested PHMSA allow operators to take a pressure reduction other than 80 percent if they documented the analysis performed and assumptions used. These commenters claimed that, as proposed in the NPRM, operators were allowed to use a different pressure reduction in HCAs if an analysis supported it but were not allowed to do so in non-HCAs.

During its meeting in late March 2018, the GPAC recommended PHMSA clarify that pressure reductions would be required for immediate conditions in non-HCAs and in cases where repair schedules could not be met. As a part of this recommendation, the GPAC also recommended that operators notify PHMSA when they could not meet the schedule for anomaly evaluation and remediation or when a temporary pressure reduction exceeds 365 days. The GPAC also recommended that PHMSA should allow operators to calculate pressure reductions (following the discovery of repairable conditions) by using either class location factors, or 80 percent of the operating pressure, or 1.1 times the predicted failure pressure. The GPAC also recommended PHMSA require that operators document and keep records, for 5 years, of the calculations and decisions used to determine such pressure reductions and the implementation of the actual reduced operating pressure. Further, the GPAC recommended PHMSA avoid duplicating language regarding the need for repairs and pressure reductions found in other sections of the regulations.

3. PHMSA Response

In the 2019 Gas Transmission Rule, PHMSA promulgated new requirements for operators to conduct integrity assessments in areas outside of HCAs, including all Class 3 and Class 4 locations and the newly defined ''moderate consequence areas'' (MCA) that are piggable. This new requirement was in response to the congressional mandate in the 2011 Pipeline Safety Act (Pub. L. 112–90) to expand IM or elements of IM beyond HCAs. The non-HCA repair criteria PHMSA is issuing in this final rule are the companion requirements to those assessments and are necessary to extend the assessment and repair program elements of IM effectively to areas beyond HCAs. Although PHMSA agrees that this requirement will likely result in additional repairs, PHMSA believes it is necessary and important to assure that injurious defects are remediated before they lead to loss of pipeline integrity.

Commenters requested that the non-HCA repair criteria be split out from the general non-IM repair provisions that previously existed in the regulations. PHMSA determined that the non-HCA repair criteria would be clearer and easier to comply with if they were in a distinct section, and PHMSA has created a new § 192.714 with all of the non-HCA repair criteria.

To the comments that suggested that a different schedule be created for immediate conditions within HCAs and non-HCAs, PHMSA believes that the existing approach used in subpart O for HCAs is better because the identification of anomalies based on ILI results is an actionable indication that there might be an injurious defect in the pipeline. Establishing repair criteria based on operators discovering these actionable anomalies assures that the anomaly is investigated promptly and repaired, if necessary. PHMSA believes it is prudent for an operator to perform any necessary repairs once the operator has excavated the pipe and exposed the anomaly for field investigation, instead of deferring the repairs. Although PHMSA agrees that defects in HCAs, if they were to fail, could result in higher consequences, PHMSA reminds readers that ASME/ANSI B31.8S, section 7.2, defines an immediate condition as an ''indication show[ing] that [a] defect is at failure point.'' PHMSA believes that any indication of a pipe that is at the point of failure needs to be addressed immediately, and as such, for both HCAs and non-HCAs, operators must reduce pressure and immediately remediate the anomaly.

PHMSA agrees with several commenters and the GPAC recommendations for consistently addressing pressure reductions for repairs for both HCA and non-HCA pipeline segments. PHMSA believes that pressure reductions are needed for immediate conditions and when repair schedules cannot be met and has incorporated pressure reductions for non-HCA pipelines that are like the existing requirements for HCAs in subpart O, which include the operator notifying PHMSA. PHMSA also agrees that the amount of the pressure reduction should be established to be 80 percent of the operating pressure at the time of discovery of the defect, or the predicted failure pressure divided by 1.1, or the predicted failure pressure times the design factor for the class location in which the affected pipeline is located, and that records for such pressure reductions must be kept for a minimum of 5 years. PHMSA incorporated these provisions, as recommended by the GPAC, in § 192.714(e) for non-HCA pipelines. Further, PHMSA followed the GPAC recommendation for reducing duplicative language regarding repairs and pressure reductions and has streamlined this final rule accordingly.

PHMSA also notes that AGA suggested creating a new subpart for non-HCA assessments and repairs. Although PHMSA has not created a new subpart, PHMSA believes it has accomplished the same purpose by putting the new non-HCA assessment and repair requirements in separate, distinct sections.

F. Repair Criteria—§§ 192.714, 192.933

iii. Cracking Criteria—§§ 192.714(d)(1)(v) & 192.933(d)(1)(v)

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to add criteria to address cracking and crack-like defects, including SCC, because the existing regulations have no explicit repair criteria for those types of critical defects. The cracking criteria would apply to both HCAs and non-HCAs, but they would require repair at different size thresholds and at different timeframes depending on the anomaly location.

Following the Enbridge incident near Marshall, MI, the NTSB recommended that PHMSA revise the hazardous liquid regulations at § 195.452 to state clearly: (1) when an engineering assessment of crack defects, including environmentally assisted cracks, must be performed; (2) the acceptable methods for performing these engineering assessments, including the assessment of cracks coinciding with corrosion with a safety factor that considers the uncertainties associated with sizing of crack defects; (3) criteria for determining when a probable crack defect in a pipeline segment must be excavated and time limits for completing those excavations; (4) pressure restriction limits for crack defects that are not excavated by the required date; and (5) acceptable methods for determining crack growth for any cracks allowed to remain in the pipe, including growth caused by fatigue, corrosion fatigue, or SCC as applicable.[31] Although the recommendation was limited to hazardous liquid pipelines, the issue applies equally to gas transmission pipelines, as SCC can occur on these pipelines as well.

Therefore, in the NPRM, PHMSA proposed to allow operators to use an engineering critical assessment (ECA) to evaluate indications of SCC. If the SCC was ''significant,'' it would be categorized as an ''immediate'' repair condition. If the SCC was not ''significant,'' it would be categorized as a ''1-year'' condition. Further, PHMSA proposed to adopt the definition of significant SCC from the consensus industry standard NACE SP0204–2008. PHMSA also proposed that an operator could not use an ECA to justify not remediating any known indications of SCC.

The current regulations also do not have repair criteria for seam cracks or crack-like flaws. Current regulations also fail to address corrosion affecting a longitudinal seam and selective seam weld corrosion, which are time-sensitive integrity threats that behave like cracks and are categorized as crack-like defects. In the NPRM, PHMSA proposed to address these gaps by including repair criteria for cracks and crack-like flaws in § 192.933 and proposed similar criteria in § 192.713.

2. Summary of Public Comment

INGAA, API, and Piedmont strongly opposed the proposed provisions in § 192.713(d)(1)(v), that stated ''any indication of significant SCC'' constitutes an immediate repair condition. Commenters requested that PHMSA determine the repair condition of cracks and crack-like defects according to factors that capture the severity of the defect, such as predicted failure pressures or maximum depth. Many commenters believed that PHMSA's proposed criteria were too conservative and suggested the repair criteria be for anomalies with a crack depth of greater than 70 percent of the pipe wall thickness or with a predicted failure pressure of less than 1.1 times MAOP. Other commenters suggested PHMSA delete the definitions of specific significant crack defects and use the alternative cracking criterion proposed by PHMSA at the GPAC meeting on March 2, 2018.

INGAA recommended making the repair criteria for cracking consistent with the repair criteria for metal loss and suggested that PHMSA consider anomalies with a crack depth of 80 percent wall thickness as immediate conditions for this reason. INGAA also recommended that PHMSA adopt a failure pressure ratio approach for cracking.

Certain commenters noted that the classification of all cracks or crack-like defects as 2-year repair conditions was overly conservative and suggested PHMSA relax that requirement. For example, some commenters suggested requiring repairs at 50 percent crack depth or a predicted failure pressure of less than 1.25 times MAOP.

At the GPAC meeting, for the proposed repair criteria for cracks, members representing the industry stated PHMSA's criteria for the immediate repair of certain crack defects were too conservative and suggested establishing an immediate repair threshold for cracks up to 70 percent of wall thickness or those with a predicted failure pressure of less than 1.1 times MAOP rather than those cracks with a predicted failure pressure of less than 1.25 times MAOP. Members representing the public noted that public safety would be better served by the threshold for immediate crack repairs being more conservative but questioned whether the more stringent threshold would be practical.

Similarly, members representing the industry suggested that PHMSA's proposed criteria for 1-year and 2-year scheduled conditions were too conservative as well and suggested setting the relevant criteria as those cracks with a depth of 50 percent wall thickness or those cracks with a predicted failure pressure of less than 1.25 times MAOP. Members representing the industry also suggested that, in addition to relaxing the criteria for immediate cracks, PHMSA should also add language requiring operators to consider tool tolerance and other factors when examining crack growth rates. Further, members representing the industry suggested that PHMSA base the repair criteria on design conditions or design factors rather than class location factors. Committee members also suggested that PHMSA cross-reference specific regulatory language rather than repeat the text in full in other sections of the code.

Following the discussion, the committee voted 12–0 that, as published in the **Federal Register**, the provisions in the proposed rule and draft regulatory evaluation for cracking repair criteria were technically feasible, reasonable, cost-effective, and practicable if PHMSA: (1) struck the proposed definitions of ''significant seam cracking'' and ''significant stress corrosion cracking,'' (2) deleted the phrase ''any indication of'' from the repair criteria related to cracking, (3) combined the criteria for SCC and seam cracking, (4) required that operators calculate predicted failure pressures for all time-dependent cracking anomalies by using the fracture mechanics

[31] NTSB Recommendation P–12–3, available at *https://www.ntsb.gov/_layouts/ntsb.recsearch/Recommendation.aspx?Rec=P-12-003.*

procedure PHMSA developed, (5) revised the definition of ''hard spot'' as discussed,[32] and (6) considered specific crack repair criteria as immediate conditions. Those specific crack repair criteria for immediate conditions would include (1) crack depth plus corrosion greater than 50 percent of pipe wall thickness; (2) crack depth plus any corrosion is greater than the inspection tool's maximum measurable depth; or (3) the crack anomaly is determined to have a predicted failure pressure that is less than 1.25 times MAOP.

3. PHMSA Response

In this final rule, PHMSA did not adopt the proposed definitions of ''significant seam cracking'' and ''significant stress corrosion cracking.'' With the revisions to the cracking repair criteria, these definitions weren't necessary. Similarly, with the deletion of the proposed repair criteria using those specific definitions, the recommendation for deleting the phrase ''any indication of'' from those criteria, became moot. Further, PHMSA's revisions to the cracking repair criteria also made the recommendation for PHMSA to combine the proposed SCC criteria and the seam cracking criteria moot.

PHMSA believes that the repair criteria it proposed in the NPRM for cracks are consistent with research findings and provides an adequate safety margin while accounting for the severity of the defects through the analysis of the predicted failure pressure.[33] PHMSA believes the repair criteria for cracks that were suggested by some of the commenters would not provide an adequate safety margin due to factors including the accuracy of tool results, varying pipe toughness, and pressure cycling. This was discussed at length by the GPAC, who ultimately recommended that anomalies be classified as immediate conditions where the crack depth plus corrosion is greater than 50 percent of pipe wall thickness, compared to certain commenters who suggested that cracks with a depth of up to 70 percent pipe wall thickness be classified as immediate conditions.

While the GPAC did not have an explicit recommendation for scheduled (*i.e.,* non-immediate) crack repair criteria, they recommended that PHMSA consider a repair schedule for cracks that is less conservative than what was proposed in the NPRM. Their recommended schedule is: 1.39 times MAOP for Class 1 and 2 locations and 1.5 times MAOP for Class 3 and 4 locations. PHMSA considered this recommendation and determined that the condition should cover Class 1 locations and Class 2 locations containing Class 1 pipe that has been uprated in accordance with § 192.611, where the predicted failure pressure is 1.39 times MAOP. For all other Class 2 locations and higher class locations, the predicted failure pressure would be 1.5 times MAOP. Section 192.611 allows Class 1 pipe to remain in a Class 2 location if it has had a subpart J pressure test, for 8 hours, at 1.25 times MAOP. Also, it allows pipe with a design factor of 0.72, with the reciprocal of 1 divided by 0.72 being equal to 1.39, which is the predicted failure pressure. Therefore, PHMSA elected to apply a predicted failure pressure ratio of 1.39 times MAOP to both Class 1 pipe and uprated Class 2 pipe.

For immediate conditions, the GPAC asked PHMSA to consider if a less conservative repair criterion of 1.1 times MAOP (after tool tolerance had been applied) would be appropriate. PHMSA considered this suggestion but notes that, after allowing for pressure excursions above MAOP due to over pressure protection device settings, the actual safety margin of such an approach would be between 0 and 6 percent. PHMSA has determined that this safety margin for immediate crack conditions is inadequate and, for this final rule, has retained the requirement that operators must immediately repair crack anomalies with a predicted failure pressure that is less than 1.25 times MAOP.

PHMSA took technical guidance information from several sources into account regarding significant SCC and significant seam weld corrosion when creating the repair criteria for these anomalies, including ASME ST–PT–011 (''Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas'').[34]

ASME ST–PT–011 states that stress corrosion cracks are ''Noteworthy'' if the maximum crack depth is greater than 10 percent of the wall thickness and if the maximum interacting crack length is more than the critical length of a 50 percent through-wall crack at a stress level of 110 percent SMYS.[35] The report provides categories as follows:

Category 1: Predicted Failure Pressure (PFP) is above 110 percent SMYS (note that 110 percent SMYS is used to delineate Category 1 cracks because it corresponds to the pressure most commonly prescribed for hydrostatic testing).

Category 2: PFP is above 125 percent MAOP[36] and below 110 percent SMYS.

Category 3: PFP is above 110 percent MAOP and below 125 percent MAOP.

Category 4: PFP is below 110 percent MAOP.

Category Zero: A crack below the threshold for Noteworthy cracks. These typically fall into two groups: (1) Those that are shallow (*i.e.,* less than 10 percent through-wall depth), or (2) Those that are so short that, even if they were 50 percent through-wall depth, they would not result in a hydrostatic test failure.

In this final rule, operators can use an engineering analysis on cracks in Categories 1 through 2 as described above. However, any Category 3 or 4 cracking defect below 125 percent MAOP would require immediate remediation. Category 3 cracks would have a 10 percent or greater safety factor, which is similar to how PHMSA currently treats corrosion anomalies at § 192.933. PHMSA provides more conservatism in the cracking criteria because there is more uncertainty with the accuracy of current ILI technology in its ability to measure crack length and depth, as well operational factors.

These severity categories allow operators to estimate the minimum remaining life at operating pressure for each category. The following estimates from ASME ST–PT–011 are based on the time it would take for the crack depth to increase to a failure-causing depth at the operating pressure. For pipelines operating at 72 percent SMYS, the following minimum operational lives for each category of cracks are as follows:

[32] This is discussed more under the ''Definitions'' subsection of this section.

[33] See ASME, ''STP–PT–0011:Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas'' (2008). See also Young, B.A., et al., ''Comprehensive Study to Understand Longitudinal ERW Seam Failures'' (2017), available at *https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=390.* Both papers call for anomaly evaluation; the knowledge of certain properties, including the length and depth of the crack, and pipe properties like wall thickness, grade, and toughness; and a proposed safety factor based on the time until the next assessment period. The papers also require that the depth of a crack not be greater than the depth of the assessment tool's tolerance. See § 192.712(e).

[34] ASME, ''STP–PT–011: Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas'' (2008).

[35] PHMSA notes that 110 percent SMYS for a Class 1 pipeline is roughly equivalent to 1.49 times MAOP.

[36] PHMSA notes that 125% times MAOP for a pipeline that operates at 72% SMYS in a Class 1 location would correspond to roughly 90% SMYS for a Category 2 crack. PHMSA has defined in § 192.506 that a spike test for cracking should be conducted at a pressure of 100 percent of SMYS (roughly equivalent to 1.39 times MAOP for a Class 1 location) or 1.5 times MAOP.

Category Zero: Failure life exceeds 15 years (for short cracks) to 25 years (for shallow cracks).

Category 1: Failure life exceeds 10 years.

Category 2: Failure life exceeds 5 years.

Category 3: Failure life exceeds 2 years.

Category 4: Failure may be imminent.

ASME ST–PT–011 further states that mitigating a pipeline segment with SCC should be commensurate with the severity of the discovered crack, which would reflect the PFP and the estimated life at the operating pressure. For example, Category Zero cracks may warrant no more than ongoing SCC condition monitoring and reassessment after a period of 7 years. Cracks may be best assessed by direct assessment, hydrostatic testing, or ILI. The most severe cases would require an immediate pressure reduction, repair (if the location is known), and hydrostatic testing or ILI, followed by replacing the pipe or installing an appropriate sleeve over the crack or known cracking areas.

F. Repair Criteria—§§ 192.714, 192.933

iv. Dent Criteria—§§ 192.714 & 192.933

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed that dents in non-HCA segments with any indication of metal loss, cracking, or a stress riser would be considered ''immediate'' repair conditions. Additionally, PHMSA proposed that dents meeting the ''1-year'' repair conditions under § 192.933 would be required to be repaired in non-HCAs within 2 years.

2. Summary of Public Comment

Multiple commenters, including the industry trade associations and operators, disagreed that all dents with metal loss should be considered immediate repair conditions. These commenters requested that PHMSA's final rule address different kinds of dents separately. Many pipeline operators stated that dents with metal loss from ''scratches, gouges, and grooves'' are appropriate as immediate repair conditions, while dents caused by corrosion are lower risk and should be conditions scheduled for later repair. Several organizations cited API Publication 1156 [37] and ASME/ANSI B31.8, ''Gas Transmission and Distribution Piping Systems,'' to support these claims. Several commenters also recommended that PHMSA impose different response timelines for dents depending on the location and the manner of the dents, because dents with bottom-side metal loss are usually corrosion-related and low-risk, while dents on the top of the pipeline with metal loss are likely to be from mechanical damage and are at a higher risk to fail. This distinction would be consistent with the criteria for smooth dents (dents with no peaks, buckling, gouging, cracking, or metal loss that can reduce the operational life of the pipe).

With further regard to the repair criteria for dents, commenters representing the industry believed PHMSA should allow operators to use an ECA to evaluate dents as an alternative to following the prescribed repair criteria. Some of this discussion focused on whether PHMSA should include a finite element analysis (FEA) [38] as part of the ECA and whether PHMSA should define critical strain levels as a criterion in the ECA. Comments from industry additionally suggested that the criterion related to gouges or grooves greater than 12.5 percent of wall thickness was duplicative with other criteria. Industry trade associations noted that gouges and grooves would be evaluated in accordance with the dent, metal loss, or cracking criteria, and therefore, a separate anomaly category for gouges and grooves should be removed. Further, they asserted that current ILI technology can't determine the specific cause of metal loss, which would make this criterion unfeasible.

At the GPAC meeting on March 26, 2018, the committee recommended changes to several of the specific repair criteria for cracks, corrosion metal loss, and dents. Specific to dents, the committee recommended that PHMSA allow use of an ECA to evaluate certain dent-related anomalies and incorporate the ECA into the repair criteria.[39]

Following the discussion, the committee voted 12–0 that, as published in the **Federal Register**, the provisions in the proposed rule and draft regulatory evaluation for dent repair criteria were technically feasible, reasonable, cost-effective, and practicable if PHMSA: (1) allowed operators to use an ECA for specific dent-related repair criteria and considered language to accommodate alternative ECA methods (including an FEA), and (2) distinguished between top-side dents that exceeded critical strain levels and bottom-side dents that exceeded critical strain levels by making distinct criteria for those anomalies.

3. PHMSA Response

PHMSA believes that the repair criteria it proposed in the NPRM for dents provide an adequate safety margin and believes the criteria for dents that were suggested by some of the commenters would not provide adequate safety margin. PHMSA based this judgment on R&D programs that have been sponsored by PHMSA and the Pipeline Research Council International, and on elements of dent repair criteria that are contained within API RP 1183.[40]

PHMSA agrees with the GPAC recommendation for allowing an ECA method to evaluate dent anomalies and has revised the dent repair criteria for immediate, scheduled, and monitored conditions, as recommended by GPAC, to do so. PHMSA believes that the development of high-resolution deformation ILI tools has advanced enough to justify allowing operators to use an ECA method to evaluate dent anomalies and believes that it would be consistent with public safety while providing operators additional flexibility. While this rulemaking was under development, API published API RP 1183, which provides guidance for assessing and managing dents that are present in pipeline systems as a result of contact by rocks, machinery, or other forces. The RP presents guidance for developing a dent assessment and management program by (1) providing suitable methods for inspecting and characterizing the condition of the pipeline with respect to dents; (2) establishing data screening processes to evaluate dents relative to the extent and degree of deformation and operational severity; (3) providing response criteria for dents based on the dent shape and profile as determined by ILI; (4) applying engineering assessment methods to evaluate the fitness-for-service of dents, including the reassessment interval; (5) presenting remediation and repair options to address dents; and (6) developing preventive and mitigative measures for dents in lieu of, or in addition to,

[37] API, ''Pub. 1156: Effects of Smooth and Rock Dents on Liquid Petroleum Pipelines'' (1997).

[38] FEA is a modeling technique used to find and solve structural or integrity issues for phenomena such as cracking or denting. Pipe properties, including the parameters of the damage to the pipe, planned operating pressure, lifespan until the next evaluation, and any future operational conditions (max pressure, pressure cycle, higher temperatures), are needed to perform an FEA.

[39] Many of the recommended changes to the proposed repair criteria were highly technical in nature. For more information, including transcripts of the discussion and the voting slides, please visit: *https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=132.*

[40] API, Recommended Practice 1183, ''Assessment and Management of Dents in Pipelines'' (Nov. 2020).

periodic dent integrity assessment, including pressure reductions and pressure cycle management.

PHMSA agrees with commenters that the criteria based on gouges and grooves would be duplicative with other criteria being proposed in the NPRM, namely the criteria related to metal loss anomalies. Accordingly, PHMSA has removed the criteria related to gouges and grooves from this final rule.

In the 2019 Gas Transmission Rule, PHMSA finalized an ECA method for operators to use as a part of the pipeline material property and attribute verification under § 192.607 and the MAOP reconfirmation requirements of § 192.624. A key aspect of that ECA method is the detailed analysis of the remaining strength of pipe with known or assumed defects. The 2019 Gas Transmission Rule created a new section, § 192.712, to address the techniques and procedures an operator could use to analyze the predicted failure pressures for pipe with corrosion metal loss and cracks or crack-like defects.[41] That analysis requires the conservative analysis of the defect to determine the remaining life of the pipeline. In this final rule, PHMSA is building on the provisions it promulgated in the 2019 Gas Transmission Rule by allowing operators to use such an analysis for determining the timing of certain anomaly repairs, including dents. Unlike the previously existing repair criteria, which required the repair of listed anomalies within a specific timeframe, operators, per this final rule, can perform this analysis to determine whether the predicted failure pressure of the anomaly would warrant additional monitoring and a later repair. PHMSA understands that operators may propose, for PHMSA review in accordance with § 192.18, procedures for the assessment and remediation of dent anomalies (such as an ECA for dent anomalies); operators may develop those procedures using consensus industry standards (*e.g.,* API RP 1183, ASME B31.8, ASME B31.8S) or current research findings.

F. Repair Criteria—§§ 192.714, 192.933

v. Corrosion Metal Loss Criteria—§§ 192.714 & 192.933

1. Summary of PHMSA's Proposal

The required remediation of several types of corrosion defects that are incorporated in the hazardous liquid regulations in part 195 are currently omitted from part 192. The current gas transmission IM regulations allow operators to use ASME/ANSI B31.8S, Figure 4, for guiding repair decisions not specified in § 192.933(d), which can allow operators significant discretion in assessing and remediating pipe with corrosion or metal loss defects. PHMSA has found a wide variation in operators' interpretation of how to meet the requirements of the regulations in assessing, evaluating, and remediating corrosion and metal loss defects.

To address these gaps, and to harmonize part 192 with part 195, PHMSA proposed to amend § 192.933 to designate as immediate repair conditions those anomalies where metal loss is greater than 80 percent of nominal wall thickness and for indications of metal loss affecting certain legacy pipe with longitudinal seams.

To address gaps related to non-immediate conditions, the NPRM proposed that operators must repair the following within 1 year: (1) anomalies where a calculation of the remaining strength of the pipe shows a predicted failure pressure ratio at the location of the anomaly less than or equal to 1.25 times the MAOP for Class 1 locations, 1.39 times the MAOP for Class 2 locations, 1.67 times the MAOP for Class 3 locations, and 2.00 times the MAOP for Class 4 locations (comparable to the alternative design factor specified in § 192.620(a)); (2) areas of general corrosion with a predicted metal loss greater than 50 percent of nominal wall thickness; (3) anomalies with predicted metal loss greater than 50 percent of nominal wall thickness that are located at crossings of another pipeline, are in areas with widespread circumferential corrosion, or are in areas that could affect a girth weld; and (4) anomalies with metal loss due to gouges or grooves[42] that are greater than 12.5 percent of nominal wall thickness.

2. Summary of Public Comment

A commenter noted that PHMSA should recognize that gouges and scrapes are metal loss defects that can be smoothed by grinding to eliminate stress concentrations.

Multiple commenters also provided input on the proposed provisions that determine repair criteria for metal loss affecting certain pipe with longitudinal seams. INGAA, AGA, and a pipeline industry entity generally supported a classification of ''immediate'' for anomalies with ''an indication of metal loss affecting a detected longitudinal seam, if that seam was formed by direct current or low frequency or high frequency electric resistance welding or by electric flash welding.'' However, PG&E requested that PHMSA not classify metal loss affecting a detected longitudinal seam as an immediate repair condition if that seam was formed by high-frequency electric resistance welding, as that pipe is considered ductile. National Fuel requested that PHMSA categorize longitudinal seam metal loss based on a minimum metal-loss threshold rather than ''an indication.'' Certain commenters requested PHMSA allow operators to perform a fitness-for-service evaluation or ECA on selective seam weld corrosion.

Kern River suggested PHMSA should consider applicable manufacturing and tool detection tolerances in the establishment of repair criteria that require response to ''any indication of metal loss.''

Several commenters, including AGA, Pauite, and DTE, did not support the proposed inclusion of ''any indication of significant seam weld corrosion'' in § 192.713(d)(1)(vi). INGAA and AGA asserted that seam weld corrosion can only be conclusively determined by an in-field examination even though ILI tools are often employed to identify possible seam weld corrosion areas.

INGAA requested that gouge and groove metal loss anomalies be deleted from the 1-year and 2-year response conditions. Other commenters noted that current ILI tools do not have the capability of differentiating 12.5 percent gouge or groove metal loss anomalies from 12.5 percent external corrosion metal loss anomalies and suggested PHMSA delete this proposed requirement. These commenters argued that, given current ILI technology and per this proposal, operators would be required to investigate all metal loss indications greater than 12.5 percent to determine if the metal loss was a gouge or groove. Several trade associations and pipeline industry entities requested that operators be allowed to perform excavations to validate ILI results before classifying a segment as a high-priority repair.

Several pipeline industry commenters disagreed with the proposed repair criteria and repair methods that differed from industry standard ASME/ANSI B31.8S. For example, AGA stated that they opposed the inclusion of different repair criteria for different class locations because this contradicts ASME/ANSI B31.8S. API noted that PHMSA's proposal contradicted the ASME/ANSI standard by including depth-based criteria and also stated that PHMSA should not include the depth-

[41] See 84 FR 52236, 52237.

[42] Gouges or grooves are stress concentrators that lead to cracking and fatigue, which in turn may lead to accelerated failure.

based criteria but only reference ASME/ANSI B31.8S, which is considered the best accepted practice. Similarly, INGAA recommended that PHMSA allow operators to use the repair methods in ASME/ANSI B31.8S rather than the proposed criteria.

Some commenters thought that the new proposed criteria for corrosion anomalies made the existing corrosion repair requirements at § 192.485(c) duplicative and requested PHMSA delete the existing corrosion repair requirements for clarity. Other commenters noted that PHMSA's proposed requirement for corrosion greater than 50 percent of wall thickness was redundant to other proposed corrosion metal loss defects and suggested this specific item should be deleted. Similarly, commenters suggested that the criteria for predicted metal loss greater than 50 percent of nominal wall located at the crossing of another pipeline, areas with widespread circumferential corrosion, or areas that could affect a girth weld were both too conservative and duplicative of other corrosion repair criteria.

At the GPAC meeting on March 26, 2018, regarding the general provisions and applicability of the corrosion metal loss repair criteria, commenters representing the industry noted that for 1-year and 2-year scheduled conditions, the use of class location safety factors would be burdensome, as it would require more frequent repairs for pipelines in Class 2, Class 3, or Class 4 locations than contemplated by consensus industry standard ASME/ANSI B31.8S section 7, figure 4.

The committee also discussed specific requirements related to the repair of corrosion anomalies. Echoing many of the public comments on the topic, members representing the industry believed that the newly proposed corrosion repair requirements were either overly conservative or duplicative compared to existing repair requirements in the corrosion control subpart. These committee members suggested the new requirements should be deleted or otherwise changed to be less conservative. Additionally, these members noted that the proposed criteria for anomalies where corrosion is greater than 50 percent of wall thickness would be redundant with other repair criteria for evaluating corrosion metal loss defects using accepted analysis techniques, such as ASME B31G and remaining strength of corroded pipe (RSTRENG).[43] Further, for corrosion metal loss affecting pipe seams, members representing the industry suggested the criteria should apply to corrosion that ''preferentially'' affects the long seam,[44] and that PHMSA should allow an ECA to analyze such defects to prevent unnecessary excavations.

The committee also suggested that PHMSA evaluate predicted failure pressure ratings and thresholds for remediation schedules of anomalies at pipeline crossings with widespread circumferential corrosion or with corrosion that can affect a girth weld.

Following the discussion, the committee voted 11–0 that, as published in the **Federal Register**, the provisions in the proposed rule and draft regulatory evaluation for corrosion metal loss repair criteria (excluding the repair timing) were technically feasible, reasonable, cost-effective, and practicable if PHMSA: (1) clarified that the criteria do not apply to corrosion pits near a long seam but does apply to corrosion along seams that could lead to slotting-type crack-like defects, (2) deleted duplicative criteria, (3) cross-referenced the proposed new fracture mechanics section with the general corrosion remediation requirements, and (4) revised the repair criteria for scheduled conditions regarding the predicted failure pressure as discussed by the committee.

The committee then voted 8–3 (with each of two members representing State regulators and one member representing the public dissenting) that, as published in the **Federal Register**, the provisions in the proposed rule and draft regulatory evaluation for scheduled conditions regarding the predicted failure pressure repair criteria for corrosion metal loss anomalies were technically feasible, reasonable, cost-effective, and practicable if PHMSA: (1) incorporated ASME/ANSI B31.8S, section 7, figure 4, into the repair criteria; (2) required operators to consider ILI tool tolerance on all runs; (3) removed and revised the predicted failure pressure standards for metal loss anomalies per the discussion of the committee; and (4) provided guidance to improve the understanding and use of ASME/ANSI B31.8S, section 7, figure 4.

For corrosion metal loss anomalies that meet the ''scheduled'' criteria (*i.e.,* 1-year conditions for HCAs and 2-year conditions for non-HCAs), the GPAC voted 8–3 that PHMSA should remove the predicted failure pressure standards for Class 1 and Class 2 segments from the NPRM and require operators to use section 7, figure 4 from ASME/ANSI B31.8S instead (*i.e.,* retain the current requirement in place for HCAs under subpart O).

3. PHMSA Response

When developing the repair criteria in the NPRM, PHMSA evaluated grounding the predicted failure pressure for those criteria in one or more of the following three factors: (1) the test pressure of a pipeline, (2) the design factor of a pipeline, and (3) the HCA repair criteria. Because PHMSA sought to improve upon existing HCA repair criteria, PHMSA decided against using that factor as the basis for calculating predicted failure pressures and proposed using test pressure or design factor of a pipeline instead. PHMSA based its proposed threshold for Class 1 pipelines (less than or equal to 1.25 times MAOP predicted failure pressure) on the maximum test pressure in § 192.619 for Class 1 pipelines (1.25 times MAOP). For the repair thresholds for Class 2, Class 3, and Class 4 pipelines, PHMSA calculated predicted failure pressures using the reciprocals of the design factors listed at § 192.111 for the immediately preceding class location rating. This approach ensured an adequate margin to failure even if the pipeline were to experience a one-class bump (pursuant to § 192.611) from changes in population density of the surrounding area. The resulting predicted failure pressure thresholds were less than or equal to 1.39 times MAOP (reciprocal of the 0.72 Class 1 design factor) for pipelines in a Class 2 location, less than or equal to 1.67 times MAOP for pipelines in Class 3 locations, and less than or equal to 2.00 times MAOP for pipelines in Class 4 locations.

PHMSA believes the repair criteria for corrosion metal loss that were suggested by some of the commenters would not provide adequate safety margin compared to what PHMSA proposed in the NPRM. This was discussed at length by the GPAC, who recommended repair criteria that, in some cases, were less conservative than what PHMSA proposed in the NPRM.

In this final rule, PHMSA adopted the GPAC's recommendation to incorporate ASME/ANSI B31.8S section 7, figure 4, into the repair criteria by requiring operators to use it in Class 1 locations for metal loss anomalies with a

[43] Both are incorporated by reference at § 192.7; see (c)(4): ASME/ANSI B31G–1991 (Reaffirmed 2004), ''Manual for Determining the Remaining Strength of Corroded Pipelines,'' 2004, and (j)(1): AGA, Pipeline Research Committee Project, PR–3–805, ''A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe,'' (December 22, 1989).

[44] Corrosion that ''preferentially'' affects the long seam is corrosion that is of and along the weld seam that is classified as selective seam weld corrosion. It normally effects low frequency electric resistance weld seams (LF–ERW) and electric flash welded seams (EFW).

predicted failure pressure greater than 1.1 times MAOP, which is consistent with the previous IM repair regulations. The committee also recommended PHMSA provide additional guidance on the use of ASME/ANSI B31.8S section 7, figure 4. ASME/ANSI B31.8S, section 7, figure 4 has three scales for repair that are based on the MAOP of the pipeline and the MAOP's percentage of the pipeline's SMYS.[45] Operators can use one of the 3 sliding scales of figure 4, as appropriate, to address anomalies when the anomaly has a failure pressure ratio above 1.1. As discussed previously, operators are currently required to follow ASME/ANSI B31.8S section 7, figure 4 under elements of the previous IM repair regulations. PHMSA understands that the 10 percent nominal safety margin provided by compliance with ASME/ANSI B31.8S section 7, figure 4 is appropriate for the relatively low risk to public safety posed to pipelines in low-population-density, Class 1 locations.

However, PHMSA did not accept the GPAC's recommendation for Class 2 locations. The number of immediate repair conditions being discovered during reassessments in Class 2 locations continues at approximately the same rate as they were discovered during the baseline assessment phase of the IM rule promulgated in 2004, according to PHMSA annual report data. PHMSA attributes this to defects that are not repaired and allowed to grow to a size that are at or near failure (*i.e.,* an immediate condition). Existing immediate repair criteria for pipelines in Class 2 locations (predicated on ASME/ANSI B31.8S section 7, figure 4) allow up to a maximum 10 percent safety margin over the MAOP. However, after allowing for pressure excursions above MAOP due to overpressure protection device settings, the actual safety margin is between 0 and 6 percent. PHMSA has determined that the continued reliance on those ASME/ANSI B31.8S section 7, figure 4-derived safety margins in more densely populated Class 2 locations does not ensure adequate identification and elimination of sub-critical defects before they grow to a size that would raise immediate safety concerns. Therefore, in this final rule, PHMSA chooses to retain the NPRM's predicted failure pressure threshold for metal loss anomalies in Class 2 locations of less than 1.39 times MAOP.

For Class 3 and Class 4 locations, PHMSA considered predicted failure pressure thresholds between 1.39 times and 1.50 times MAOP as requested by the committee. However, PHMSA has determined that, in order to provide adequate margin for public safety in higher- population-density Class 3 and 4 locations, PHMSA could not establish a predicted failure pressure threshold as low as 1.39 times MAOP. Therefore, in this final rule, PHMSA has provided a repair threshold for anomalies meeting a predicted failure pressure of less than 1.50 times MAOP for pipelines in Class 3 and Class 4 locations. PHMSA notes this approach would align repair criteria with the approach in § 192.619 for determining maximum allowable pressures for the same locations, and reflects that transmission pipelines in Class 3 and Class 4 locations are more robust (as a result of thicker walls and other design requirements) than those used in Class 1 and Class 2 locations.

PHMSA has provided similar repair criteria in this final rule for corrosion metal loss anomalies that are at a crossing of another pipeline; are in an area with widespread circumferential corrosion; could affect a girth weld; or that preferentially affects detected longitudinal seams that are formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0. Specifically, PHMSA is requiring the repair of conditions that reach less than 1.39 times the MAOP for anomalies in Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611. For those corrosion metal loss anomalies at all other Class 2 locations, as well as those anomalies in Class 3 and Class 4 locations, operators will have to repair them once they reach a predicted failure pressure of less than 1.50 times MAOP.

PHMSA is requiring the additional stringency in Class 1 locations and Class 2 locations compared to the general corrosion metal loss repair standard discussed above because, should corrosion at the crossing of other pipelines induce failure, multiple pipelines could be damaged or fail. Pipelines with anomalies located at areas of widespread circumferential corrosion could additionally lose pipe strength due to outside longitudinal (pulling force) loading on the pipeline. And, historically, longitudinal seams that are formed by direct-current welding, low-frequency or high-frequency electric resistance welding, electric flash welding, or that have a longitudinal joint factor of less than 1.0, are more likely to fail. Therefore, PHMSA has determined that more stringent repair criteria are necessary for corrosion metal loss anomalies that preferentially affect these longitudinal seams. In contrast, because pipelines in Class 3 and Class 4 locations are (as noted above) more robust than those in Class 1 and Class 2 locations, PHMSA has determined that it is unnecessary to impose different thresholds for pipelines in Class 3 and Class 4 locations based on whether they are located at the crossing of another pipeline.

As explained in the discussion for dent anomalies above, PHMSA agreed with commenters that the specific criteria for gouges and grooves was duplicative with other metal loss conditions and has chosen not to finalize gouge and groove criteria in this final rule. Therefore, the comments related to whether ILI tools can properly or reliably identify gouges and grooves specifically are moot.

F. Repair Criteria—§§ 192.714, 192.933

vi. General Discussion

Process for Analyzing Defects Discovered—§ 192.933

1. Summary of PHMSA's Proposal

Following the Enbridge hazardous liquid incident in 2010 that spilled nearly 1 million barrels of oil near Marshall, MI, in 2010, the NTSB recommended that PHMSA revise requirements in the hazardous liquid pipeline safety regulations at § 195.452(h)(2) related to the ''discovery of condition'' to require, in cases where a determination about pipeline threats has not been obtained within 180 days following the date of inspection, that pipeline operators notify PHMSA and provide an expected date when adequate information will become available.[46] The NTSB also recommended that PHMSA revise part 195 to state the acceptable methods for performing engineering assessments of ILI results, including the assessment of cracks coinciding with corrosion, with a safety factor that considers the uncertainties associated with sizing of crack defects (P–12–3). Although these recommendations were for the hazardous liquid pipeline safety regulations in part 195, the issues apply equally to gas pipelines regulated under part 192.

Accordingly, PHMSA proposed to amend paragraph (b) of § 192.933 to

[45] Those three scales pertain to (1) not exceeding 30 percent SMYS, (2) above 30 percent SMYS but not exceeding 50 percent SMYS, and (3) above 50 percent SMYS.

[46] NTSB Recommendation P–12–4, available at *https://www.ntsb.gov/safety/safety-recs/_layouts/ntsb.recsearch/Recommendation.aspx?Rec=P-12-004.*

require that operators notify PHMSA within 180 days following an assessment where the operator cannot obtain sufficient information to determine if a condition presents a potential threat to the integrity of the pipeline; and expand the requirements in § 192.933 to clarify that operators must assure that persons qualified by knowledge, training, and experience must analyze the data obtained from an ILI to determine if a condition could adversely affect the safe operation of the pipeline. PHMSA also proposed to require that operators explicitly consider uncertainties in reported results in identifying and characterizing anomalies, which includes uncertainties in tool tolerance, detection threshold, the probability of detection, the probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots.

PHMSA also proposed to amend paragraphs (a) and (d) of § 192.933 to require that operators document a pipeline's physical material properties and attributes that are used in remaining strength calculations in reliable, traceable, verifiable, and complete records. If such records were not available, operators would be required to base the pipe and material properties used in the remaining strength calculations on properties determined and documented in accordance with § 192.607.

2. Summary of Public Comment

Commenters noted that there were potential issues with how the revised repair criteria and the proposed material verification requirements at § 192.607 would interact regarding remaining strength calculations. These commenters requested that, absent reliable data, PHMSA allow operators to use supportable, sound engineering judgments when calculating remaining strength. This would allow operators to establish the remaining strength of affected segments while material verification was completed. Similarly, commenters suggested if the value for specified minimum yield strength is unknown, operators should be able to use a conservative default value, such as 30,000 pounds per square inch (psi). For predicted failure pressure calculations, operators suggested they should be able to use the records they have on hand and operator knowledge for calculations until any necessary material properties are verified through § 192.607. Similarly, at the GPAC meeting on March 26, 2018, commenters representing the industry suggested PHMSA should allow, in the absence of traceable, verifiable, and complete material records,[47] for operators to use sound engineering judgment or otherwise conservative assumptions in repair-related decision making, and recommended PHMSA modify the regulations as such.

The EDF and PST supported PHMSA's proposals related to considering uncertainties in ILI results for identifying and characterizing anomalies. Several pipeline operators and industry trade associations on the other hand, including INGAA, expressed concern that the NPRM would require pipeline operators to repair anomalies that do not threaten pipeline integrity, stating that many anomalies that are identified by indirect measurements as requiring repair are later determined not to require repair upon examination in the field. These commenters requested that PHMSA change the proposed requirements to distinguish between ILI results and in-field examinations and start the repair timeline with the time an anomaly is examined in the field and not when it is identified by ILI.

INGAA suggested that PHMSA change the proposed requirements to differentiate between response, remediation, and repair, and that PHMSA replace ''repair'' with ''response'' in the terms ''2-year repair criteria'' and ''1-year repair criteria'' as those terms pertain to the non-HCA repair criteria. INGAA also requested that PHMSA further divide ''2-year response conditions'' into ''2-year response conditions and scheduled responses'' and similarly divide ''1-year response conditions'' into ''1-year response conditions and scheduled responses.'' INGAA suggested such a revision would be necessary because the proposed requirements for the response to, and repair of, potential pipeline anomalies do not recognize the differences between actions that operators take when evaluating the result of integrity assessments versus those actions operators take following in-field examinations of potential anomalies.

Several commenters requested that PHMSA change the proposed regulatory language to distinguish between ILI results and in-field examinations (response) and the actual remediation activity (repair) with a view to start the repair timeline after an anomaly is examined in the field and not when it is identified by ILI. Commenters suggested separate timelines to distinguish between the ''response'' and ''repair'' phases of pipeline remediation.

3. PHMSA Response

PHMSA addressed comments pertaining to the use of sound engineering judgment and assumed values to evaluate anomalies when data required for the evaluation is unknown or not available in traceable, verifiable, and complete records in the 2019 Gas Transmission Rule at § 192.712.[48] If an operator does not have one or more of the material properties necessary to perform an ECA analysis (diameter, wall thickness, seam type, grade, and Charpy v-notch toughness values, if applicable), the operator must use the conservative assumptions PHMSA provided and include the pipeline segment in its program to verify the undocumented information in accordance with the material properties verification requirements at § 192.607.

In the Response to Petitions for Reconsideration on the 2019 Gas Transmission Rule,[49] PHMSA stated that if operators are missing any material properties during anomaly evaluations and repairs, operators must confirm those material properties under §§ 192.607 and 192.712(e) through (g). For consistency in this final rule, and to make this requirement more explicit, PHMSA has linked those material property confirmation requirements to the anomaly repair requirements by cross-referencing § 192.607 at both §§ 192.714 and 192.933. PHMSA will also note that, in accordance with the section 23 mandate in the 2011 Pipeline Safety Act, operators reported that approximately 13 percent of pipeline segment mileage in HCAs and Class 3 and Class 4 locations lack adequate documentation of the physical and operational characteristics of the pipelines necessary to confirm the proper MAOP. Such documentation is

[47] In an advisory bulletin dated May 7, 2012 (77 FR 26822), PHMSA provided guidelines for what records would meet a traceable, verifiable, and complete standard. The phrase ''traceable, verifiable, and complete'' matched a phrase from NTSB recommendation P–10–5, which recommended to the California Public Utilities Commission to ensure that PG&E ''aggressively and diligently searched documents and records relating to [. . .] natural gas transmission lines in class 3 and class 4 locations and class 1 and class 2 high consequence areas [. . .]. These records should be traceable, verifiable, and complete [. . .].'' See NTSB Recommendation P–10–5, available at *https://www.ntsb.gov/safety/safety-recs/_layouts/ntsb.recsearch/Recommendation.aspx?Rec=P-10-005.* While PHMSA proposed that records meet a reliable, traceable, verifiable, and complete standard, PHMSA believes that being consistent with the guidance it provided in the May 2012 advisory bulletin and the NTSB recommendation will provide further clarity.

[48] See 84 FR 52236, 52251.

[49] 85 FR 40132 (July 6, 2020).

also critical for performing predicted failure pressure calculations.

In an earlier section of the repair criteria discussion, PHMSA noted that the identification of anomalies based on ILI results is an actionable indication that there might be an injurious defect in the pipeline. Establishing repair criteria based on operators discovering these actionable anomalies assures that these anomalies are investigated promptly and repaired. Therefore, PHMSA disagrees with commenters who suggested that there should be separate timelines for anomaly responses and repairs, as it would be prudent for operators to perform any necessary repairs once the operator has excavated the pipe and exposed the anomaly for investigation rather than deferring such repairs.

F. Repair Criteria—§§ 192.714, 192.933

vii. Miscellaneous Comments

1. Summary of Public Comments

Commenters were concerned that the requirements in this rulemaking would apply to gas gathering pipelines and requested that PHMSA clarify this is not the case. Similarly, the GPAC, in its late March 2018 meeting, recommended PHMSA clarify that the non-HCA repair criteria applied to those pipeline segments not currently covered under the IM regulations at subpart O.

Additionally, pipeline operators and their trade associations requested that PHMSA clarify the effective date of the repair provisions, as the requirements were proposed in an allegedly retroactive section of the regulations. These commenters claimed, as written, the proposed provisions would force operators to apply the revised repair criteria to prior ILI assessments that, at the time, met all the standards of the regulations. Some of these commenters recommended PHMSA establish reasonable, risk-based timeframes for operators to implement repairs of anomalies that were historically identified and were repaired in accordance with the code requirements of the time. The GPAC, during their meeting in late March of 2018, similarly recommended that PHMSA add an effective date to these general repair provisions to clarify that they were not retroactive.

Some commenters also discussed the application of the proposed repair criteria to pipelines outside of HCAs that have established their MAOP under the alternative requirements at § 192.620. The GPAC recommended PHMSA apply appropriate predicted failure pressure factors to alternative MAOP pipelines based on class location and design factors for scheduled conditions under the repair criteria.

2. PHMSA Response

PHMSA did not intend for the new repair criteria for non-HCA pipe segments to be applicable to gas gathering pipelines, HCA segments, or offshore transmission lines. However, PHMSA will consider expanding the application of these provisions in the future. In this final rule, to clarify that the new non-HCA repair criteria apply only to onshore transmission lines, PHMSA placed the new non-HCA repair criteria in a new § 192.714, which applies only to onshore transmission lines. Subsequently, PHMSA withdrew all proposed changes to § 192.713. PHMSA has also revised § 192.9 in this final rule to exempt regulated gas gathering lines from the requirements of § 192.714. Additionally, PHMSA has modified § 192.711 in this final rule to clarify that the new repair criteria in § 192.714 do not apply to gathering lines or HCA segments subject to subpart O. The current and unchanged § 192.713 would continue to apply to regulated gas gathering lines. Although the creation of a new § 192.714 was not discussed at the GPAC, PHMSA determined that this approach was a clearer means to specify that the new non-HCA repair criteria only apply to onshore transmission pipelines and meet the intent of the GPAC recommendation to clarify that the non-HCA repair criteria do not apply to gathering lines, HCA segments, or offshore transmission lines. Furthermore, PHMSA determined that this approach avoids duplication of repair language in other code sections.

PHMSA did not intend to imply that the new repair criteria were to be applied retroactively and has clarified this intent in this final rule by revising § 192.711(b) to include an effective date as recommended by the GPAC.

Regarding alternative MAOP pipelines, the NPRM did not propose, and therefore did not give opportunity for comment on, changes to repair criteria for alternative MAOP pipe segments. However, PHMSA agrees with commenters that the language proposed in the NPRM could create ambiguity with respect to the applicability of the non-HCA repair criteria to pipe with MAOP established in accordance with § 192.620. Therefore, in this final rule, PHMSA more broadly exempted alternative MAOP lines from compliance with non-HCA repair criteria and reiterated the applicability of the repair criteria provided at the alternative MAOP provisions under § 192.620(d)(11) as they provide a comparable level of safety based upon the operating factors. PHMSA did not make a corresponding change to § 192.933, as alternative MAOP pipelines in HCAs must meet both the HCA and the alternative MAOP repair criteria. This approach is preferable to repeating the alternate MAOP repair criteria in two locations of part 192.

G. Definitions—§ 192.3

i. Close Interval Survey

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed a new definition for ''close interval survey'' as a series of closely spaced pipe-to-electrolyte potential measurements taken to assess the adequacy of cathodic protection or to identify locations where a current may be leaving the pipeline and may cause corrosion, and for the purpose of quantifying voltage drops other than those across the structure electrolyte boundary.

2. Summary of Public Comment

Comments from the trade associations and GPAC members representing the industry questioned whether PHMSA should tie the definition of ''close interval survey'' to a corresponding NACE standard for consistency. PHMSA presented some minor changes to the definition at the meeting on March 28, 2018, and the committee voted 13–0 that PHMSA should adopt those changes into the final rule.

3. PHMSA Response

After considering the comments and GPAC recommendations, PHMSA is adopting the definition of ''close interval survey'' as recommended by GPAC. As such, PHMSA has specified that the pipe-to-electrolyte potential measurements are taken ''over the pipe,'' and added the phrase ''such as when performed as a current interrupted, depolarized, or native survey'' to qualify what is ''other than those across the structure electrolyte boundary.''

G. Definitions—§ 192.3

ii. Distribution Center

1. Summary of PHMSA's Proposal

PHMSA proposed to define a ''distribution center'' as a location where gas volumes are either metered or have a pressure or volume reduction prior to delivery to customers through a distribution line.

2. Summary of Public Comment

AGL Resources, Pipeline Safety Coalition, Southern California Gas

Company, Spire STL Pipeline LLC, and Xcel Energy supported PHMSA's intention to define the term ''distribution center.'' In particular, AGL Resources stated that the proposed definition would remove confusion and the potential for conflict between operators and regulators throughout the Nation. Like its comments on the proposed definition for ''transmission line,'' Xcel Energy suggested that PHMSA add an implementation period for operators to handle the regulatory impacts of the new definition.

AGA supported PHMSA's effort to define a ''distribution center'' to ensure consistency and certainty in the identification of transmission lines. However, AGA also stated that PHMSA failed to provide any justification or explanation for its proposed definition, and AGA proposed an alternative definition of ''distribution center'' where piping downstream of a distribution center that operates above 20 percent SMYS would be classified as a transmission line. Other organizations, such as Alliant Energy, Dominion Energy, PECO Energy, Paiute Pipeline Company, and Southwest Gas Corporation, supported AGA's alternative definition.

TPA recommended PHMSA revise the proposed definition of ''distribution center'' to provide a clear endpoint for transmission lines and the start of distribution lines. Atmos Energy stated that the proposed definition did not recognize the many possible configurations of pipes in which transmission pipelines deliver to distribution systems. For example, Oleksa and Associates stated that some distribution systems may have no meters prior to delivery to customers and also may have no pressure or volume reductions (*e.g.,* a distribution system supplied by a landfill). Lastly, Cascade Natural Gas requested the term ''distribution center'' clearly refer to distribution pipelines and that such a definition should not be included in a rulemaking for transmission and gathering pipelines.

At the GPAC meeting, PHMSA offered for the committee's consideration the option of recommending withdrawal of the proposed definition for ''distribution center.'' Committee members opposed this suggestion, stating that finalizing a definition for ''distribution center'' would provide the industry and regulators with regulatory certainty and clarity. During the meeting, committee members came to a consensus on the definition of a ''distribution center'' based on comments the industry provided. However, certain committee members representing the public were not inclined to adopt a definition of a ''distribution center'' that was based on the comments provided by industry and wished to defer to PHMSA regarding the wordsmithing of the definition.

Following the discussion, the committee voted 10–0 that the definition for ''distribution center'' was technically feasible, reasonable, cost-effective, and practicable if PHMSA incorporated a definition for ''distribution center'' in the final rule and considered revising the definition to mean the initial point where gas enters piping used to deliver gas to customers for end use as opposed to customers who purchase it for resale. Examples of a distribution center would include a metering location; a pressure reduction location; or where there is a reduction in the volume of gas, such as a lateral off a transmission pipeline.

3. PHMSA Response

After considering the comments received and the GPAC's recommendations, PHMSA is adopting the definition recommended by GPAC so that a ''distribution center'' means the initial point where gas enters piping used to deliver gas to customers for end use as opposed to customers who purchase it for resale.

PHMSA disagrees that an implementation period for the definition is appropriate, given that this term has been in use for a long period of time. PHMSA agrees with commenters for the need to clarify the end point of transmission and the start of distribution. PHMSA agrees with those commenters who suggested that piping downstream of a distribution center operating at above 20 percent SMYS should be considered a transmission line and is modifying the definition of ''transmission line'' accordingly in this final rule.

G. Definitions—§ 192.3

iii. Dry Gas or Dry Natural Gas

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed a new definition for the term ''dry gas or dry natural gas'' to mean gas with less than 7 pounds of water per million cubic feet that is not subject to excessive upsets allowing electrolytes into the gas system.

2. Summary of Public Comment

GPAC members representing the industry asked whether PHMSA should tie the definition for dry gas to the corresponding NACE standard for continuity. Committee members representing the public were concerned about incorporating by reference the definition into the regulations but were amenable to lifting the language directly from the standard to ensure consistency. PHMSA representatives noted that the agency could consider the NACE definition and make the definition for dry gas less prescriptive than proposed.

After discussion, the committee voted 13–0 that the definition for ''dry gas or dry natural gas'' was technically feasible, reasonable, cost-effective, and practicable if PHMSA revised the definition to be consistent with the NACE definition as discussed at the meeting.

3. PHMSA Response

PHMSA has taken into consideration the comments as well as the GPAC recommendations and is modifying the definition for ''dry gas or dry natural gas'' to be consistent with the NACE standard. More specifically, the definition specifies that ''dry gas or dry natural gas'' is gas ''above its dew point and without condensed liquids.''

G. Definitions—§ 192.3

iv. Electrical Survey

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed revising the term ''electrical survey'' so that it means a series of closely spaced measurements of the potential difference between two reference electrodes to determine where the current is leaving the pipe on ineffectively coated or bare pipelines.

2. Summary of Public Comment

PHMSA received a variety of comments on the definition for ''electrical survey.'' Some commenters expressed support for the definition and its inclusion in the regulations. Other commenters supported the concept of the definition but provided PHMSA with varying edits to improve on the clarity and functionality of the definition.

Several commenters noted that the proposed definition for electrical survey was duplicative with the proposed definition for ''close interval survey'' and recommended that PHMSA retain the definition for close interval survey instead. Some of these commenters noted that the proposed definition for electrical survey was more restrictive than the definition of electrical survey in NACE standards and excluded certain types of surveys. Other commenters suggested that the proposed definition for electrical survey should match the definition in various NACE standards.

NACE itself believed that the definition used in the NPRM for ''electrical survey'' was ambiguous and inaccurate, stating the proposed definition does not align with current terminology and accepted pipeline integrity practices. NACE recommended that PHMSA use the definition for ''indirect inspection'' in NACE SP0502, which is widely accepted as standard practice and should meet PHMSA's intent.

The GPAC recommended that PHMSA withdraw the proposed changes to appendix D as a part of the recommended revisions to the proposed corrosion control regulations. There was no further discussion on the definition for the term, and the committee voted, 13–0, to delete the definition from the rule.

3. PHMSA Response

PHMSA notes that, when the committee voted to withdraw the proposed changes to appendix D as a part of the corrosion control discussion, a revised definition for electrical survey was unnecessary as all references to ''electrical surveys'' were removed. Therefore, PHMSA agrees with the GPAC recommendation and has struck the proposed revision to the definition of ''electrical survey'' from this final rule.

G. Definitions—§ 192.3

v. Hard Spot

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to define a ''hard spot'' as steel pipe material with a minimum dimension greater than 2 inches (50.8 mm) in any direction with hardness greater than or equal to Rockwell 35 HRC, Brinnel 327 HB, or Vickers 345 HV_{10}.

2. Summary of Public Comment

During the GPAC meeting, committee members noted there was a small editorial correction that needed to be made—changing ''Brinnel'' to ''Brinell'' —and also recommended that the definition be prefaced with the phrase ''an area on'' so that the definition reads ''an area on steel pipe material [. . .].''

3. PHMSA Response

PHMSA has modified the proposed definition of hard spot as the GPAC recommended for this final rule.

G. Definitions—§ 192.3

vi. In-Line Inspection (ILI) and In-Line Inspection Tool or Instrumented Internal Inspection Device

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to add definitions for ''in-line inspection (ILI)'' and ''in-line inspection tool or instrumental internal inspection device'' to § 192.3. Specifically, the term ''in-line inspection'' would mean the inspection of a pipeline from the interior of the pipe using an ILI tool, which may also be known as intelligent or smart pigging. The term ''in-line inspection tool or instrumented internal inspection device'' would mean a device or vehicle that inspects a pipeline from the inside using a non-destructive technique. Such a device might also be called an intelligent or smart pig.

2. Summary of Public Comment

NACE International commented that the proposed definitions of ''in-line inspection'' and ''in-line inspection tool or instrumented internal inspection device'' do not align with the definition provided in NACE International Standard SP01024 or SP0102, respectively. NACE International suggested that PHMSA use the definition in NACE Standard SP0102, as PHMSA had proposed to incorporate by reference the standard in the regulations.

The GPAC reviewed the proposed definitions and, following their discussion, voted 13–0 that the definitions for ''in-line inspection'' and ''in-line inspection tool or instrumented internal inspection device'' were technically feasible, reasonable, cost-effective, and practicable if PHMSA considered clarifying in the preamble that the phrase ''a line that can accommodate inspection by means of an instrumented in-line inspection tool'' referred to pipeline segments that can be inspected with free-swimming ILI tools without any permanent physical modification of the pipeline segment.

3. PHMSA Response

After considering these comments, PHMSA is modifying the definitions of both ''in-line inspection'' and ''in-line inspection tool or instrumented internal inspection device'' based on the definitions in NACE SP0102–2010. In accordance with the GPAC recommendation, PHMSA is also noting that an ILI can include both tethered and self-propelled (*i.e.,* ''free-swimming'') tools.

G. Definitions—§ 192.3

vii. Transmission Line

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to modify the second criterion of the ''transmission line'' definition to base the percentage of SMYS on the MAOP of the pipeline, whereas currently it is based on the pressure at which the pipeline is operating. PHMSA also proposed editorial changes to the ''Note'' section of the definition and make it clearer that ''factories, power plants, and institutional users of gas'' were examples of a large-volume customer.

2. Summary of Public Comment

AGA asserted that modifying the second criterion in the ''transmission line'' definition in conjunction with other definition changes PHMSA proposed would result in the reclassification of some transmission pipelines to distribution lines and some distribution pipelines to transmission lines. Several pipeline operators and industry representatives, including AGL Resources, Alliant Energy, Black Hills Energy, Cascade Natural Gas, Centerpoint Energy, Spire, Delmarva Power, National Grid, National Fuel Gas Supply Corporation, North Dakota Petroleum Council, Paiute Pipelines, TECO Peoples Gas, TPA, and PECO Energy, supported AGA's comments or provided similar recommendations. Additionally, Dominion East Ohio and Southwest Gas objected to PHMSA's proposed modifications to the definition, stating that the proposed definition would burden operators with ongoing IM programs with no additional benefit to public safety.

APGA commented that PHMSA's slight rewording of the note in the transmission definition regarding types of large-volume customers could be interpreted to mean that only factories, power plants, and institutional users of gas can be large-volume customers. APGA suggested PHMSA change the proposed language in the final rule to clarify that those listed items are examples of large-volume customers rather than a comprehensive list.

ONE Gas proposed an alternative simplified approach to the definition of ''transmission line'' that focuses on a line's MAOP as it relates to the percentage of yield strength.

There were various comments from other pipeline operators, including the suggestion that PHMSA remove the term ''distribution center'' from the definition of ''transmission line,'' allow operators to use MAOP to determine a transmission pipeline, and provide an implementation period for operators to incorporate regulatory requirements of the newly defined transmission lines.

During the GPAC meeting, committee members representing the industry expressed support for allowing operators to designate pipelines voluntarily as transmission lines, especially if their risk profile was high, so that operators could operate and maintain those lines to a higher standard.

Following the discussion, the committee voted 10–0 that the definition for ''transmission line'' was technically feasible, reasonable, cost-effective, and practicable if PHMSA included the phrase ''an interconnected series of pipelines'' within the text of the definition and allowed operators to designate pipelines voluntarily as transmission lines.

3. PHMSA Response

PHMSA has considered the comments received regarding the proposed definition of a ''transmission line.'' PHMSA agrees with the recommendation from the GPAC to allow operators to designate pipelines voluntarily as transmission lines, as well as the recommendation from the GPAC to include the phrase ''an interconnected series of pipelines.'' Accordingly, PHMSA has revised the definition of ''transmission line'' in this final rule to include these recommendations.

PHMSA agrees with commenters that the language to clarify the examples of large-volume customers may imply a specific list and has withdrawn the changes to the note in the definition. In response to the comment on providing an implementation period for compliance with the new definition, PHMSA notes that it does not apply separate implementation periods to definitions outside of the effective date of the rule. If PHMSA determines that corresponding regulations would be affected by a change in a definition, it incorporates appropriate implementation time to those regulations as necessary.

PHMSA also notes that, per the comments received on the definition for ''distribution center,'' it agreed with commenters who suggested that piping downstream of a distribution center operating at above 20 percent of SMYS should be considered a transmission line and is modifying the definition of ''transmission line'' accordingly in this final rule.

PHMSA sees no functional difference in changing the definition of a transmission line from a pipeline that operators at a hoop stress of 20 percent or more of SMYS and a pipeline that has a MAOP of 20 percent or more of SMYS. For a pipeline to operate above 20 percent or more of SMYS, it will have an MAOP of 20 percent or more of SMYS. If an operator has a pipeline where the theoretical MAOP is higher than the pipeline's actual operating pressure, and therefore the line would need to be reclassified, the operator could reduce the MAOP of the line to keep the line's classification the same without affecting its operating pressure.

G. Definitions—§ 192.3

viii. Wrinkle Bend

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to define ''wrinkle bend'' as a bend in the pipe that was formed in the field during construction such that the inside radius of the bend has one or more ripples of various sizes or where the ratio of peaks to peaks or peaks to valleys are of a certain size, or where a mathematical equation could be substituted when a wrinkle bend's length cannot reliably be determined.

2. Summary of Public Comment

There was no significant public comment on this definition, and the GPAC recommended PHMSA adopt the definition as it was published in the NPRM.

3. PHMSA Response

PHMSA adopts the definition as it was published in the NPRM.

IV. Section-by-Section Analysis

Section 192.3 Definitions

Section 192.3 provides definitions for various terms used throughout part 192. In support of other regulations adopted in this final rule, PHMSA is amending the definition of ''transmission line'' and is adding new definitions for ''close interval survey,'' ''distribution center,'' ''dry gas or dry natural gas,'' ''hard spot,'' ''in-line inspection,'' ''in-line inspection tool or instrumented internal inspection device,'' and ''wrinkle bend.'' The definitions, including ''in-line inspection,'' ''dry gas or dry natural gas,'' and ''hard spot,'' clarify technical terms used in part 192 or in this rulemaking.

Section 192.7 What documents are incorporated by reference partly or wholly in this part?

Section 192.7 lists documents that are incorporated by reference in part 192. PHMSA is making conforming amendments to § 192.7 to include two NACE standard practice documents regarding SCCDA and ICDA.

Section 192.9 What requirements apply to gathering lines?

Section 192.9 lists the requirements that are applicable or not applicable to gathering lines. This final rule addresses several new requirements for transmission lines that are not intended to apply to gathering lines; PHMSA is adopting in this final rule revisions to § 192.9 to except each of offshore and Types A, B, and C [50] gas gathering lines from those requirements.

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

Section 192.13 prescribes general requirements for gas pipelines. PHMSA has determined that public safety and environmental protection would be improved by requiring operators of transmission lines to evaluate and mitigate risks during all phases of the useful life of a pipeline as an integral part of managing pipeline design, construction, operation, maintenance, and integrity, including the MOC process.

As such, PHMSA has added a new paragraph (d) to § 192.13 with a general clause for transmission pipeline operators that invokes the requirements for the MOC process as it is outlined in ASME/ANSI B31.8S, section 11, and explicitly articulates the requirements for a MOC process applicable to onshore gas transmission pipelines. This final rule requires each operator to have a MOC process that must include the reason for change, authority for approving changes, analysis of implications, acquisition of required work permits, documentation, communication of change to affected parties, time limitations, and qualification of staff. While these general attributes of change management are already required for covered segments by virtue of the incorporation by reference of ASME/ANSI B31.8S, PHMSA believes it will improve the visibility and emphasis on these important program elements to require them for all onshore transmission pipelines directly in the rule text.

Section 192.18 How To Notify PHMSA

Section 192.18 in subpart A contains the procedure for an operator to submit notifications to PHMSA. Paragraph (c) has been modified to incorporate notification requirements for the use of ''other technology'' with external corrosion control and ICDA per §§ 192.461(g) and 192.927(b).[51] This is

[50] PHMSA notes that it has introduced in this final rule revisions to § 192.9(e), which paragraph was adopted in the Gas Gathering Final Rule, to identify specific provisions of part 192 that would apply to the new Type C category of part 192-regulated onshore gas gathering pipelines.

[51] PHMSA notes that between publication of this final rule and its effective date, regulatory amendments to § 191.18 adopted in rulemaking published in April 2022 will have been codified in the Code of Federal Regulations. ''Pipeline Safety:

Continued

consistent with the requirements PHMSA issued with the use of other technology for provisions finalized in the 2019 Gas Transmission Rule.

Section 192.319 Installation of Pipe in a Ditch

Section 192.319 prescribes requirements for installing pipe in a ditch, including requirements to protect pipe coating from damage during the process. Sometimes pipe coating is damaged during the construction process while it is being handled, lowered, and backfilled, which can compromise its ability to protect against external corrosion. Accordingly, this final rule adds new paragraphs (d) through (g) to § 192.319, which require that onshore gas transmission operators perform an above-ground indirect assessment to identify locations of suspected damage promptly after backfilling is completed and remediate coating damage. Mechanical damage is also detectable by these indirect assessment methods, since the forces that can mechanically damage steel pipe usually result in detectable coating defects.

If an operator uses ''other technology'' to perform an assessment required under this section, paragraph (e) requires the operator to notify PHMSA in accordance with § 192.18. Paragraph (g) requires each operator of transmission pipelines to make and retain, for the life of the pipeline, records documenting the coating assessment findings and repairs. The additional requirements of this section do not apply to gas gathering pipelines or distribution mains.

Section 192.461 External Corrosion Control: Protective Coating

Section 192.461 prescribes requirements for protective coating systems. Certain types of coating systems that have been used extensively in the pipeline industry can impede the process of cathodic protection if the coating disbonds from the pipe. Accordingly, this final rule amends paragraph (a)(4) to require that pipe coating has sufficient strength to resist damage during installation and backfill, and it also adds a new paragraph (f) to require that onshore gas transmission operators perform an above-ground indirect assessment to identify locations of suspected damage promptly after backfill is completed or anytime there is an indication that the coating might be compromised. To ensure the prompt remediation of any severe coating damage, new paragraph (h) requires operators create a remedial action plan and provides the specific timing requirements for repairs. New paragraph (g) requires an operator to notify PHMSA, in accordance with § 192.18, if using ''other technology'' for the coating assessment, and paragraph (i) specifies the documentation requirements for this section. The additional requirements of this section do not apply to gas gathering pipelines or distribution mains.

Section 192.465 External Corrosion Control: Monitoring

Section 192.465 requires that operators monitor CP and take prompt remedial action to correct deficiencies indicated by the monitoring. To clarify that regulatory requirement, this final rule amends paragraph (d) to require that operators of onshore transmission pipelines must complete remedial action no later than the next monitoring interval specified in § 192.465, within 1 year, or within 6 months of obtaining any permits, whichever is less.

This final rule also adds a new paragraph (f) to require onshore gas transmission operators to conduct annual test station readings to determine if CP is below the level of protection required in subpart I. For non-systemic or location-specific causes of insufficient CP, the operator must investigate and mitigate the cause. For insufficient CP due to systemic causes, an operator must complete CIS with the protective current interrupted, unless it is impractical to do so based on a geographical, technical, or safety reason. For example, issues related to cost would not be an adequate reason for not performing the survey, whereas performing a survey on a pipeline protected by direct buried sacrificial anodes (anodes directly connected to the pipelines) might be impractical. The revisions to paragraph (d) and new paragraph (f) do not apply to gas gathering lines or distribution mains.

Section 192.473 External Corrosion Control: Interference Currents

Interference currents can negate the effectiveness of CP systems. Section 192.473 currently prescribes general requirements to minimize the detrimental effects of interference currents. However, subpart I does not presently contain specific requirements to monitor and mitigate detrimental interference currents. Accordingly, this final rule adds a new paragraph (c) to require that onshore gas transmission operator corrosion control programs include interference surveys to detect the presence of interference currents when potential monitoring indicates a significant increase in stray current, or when new potential stray current sources are introduced. Sources of stray current can include co-located pipelines, structures, HVAC power lines, new or enlarged power substations, new pipelines, and other structures. They can also include additional generation, a voltage uprating, and additional lines. The rule also requires operators perform remedial actions no later than 15 months after completing the interference survey, with an allowance for permitting, to protect the pipeline segment from detrimental interference currents. These additional requirements do not apply to gas gathering pipelines or distribution mains.

Section 192.478 Internal Corrosion Control: Monitoring

Section 192.477 prescribes requirements to monitor internal corrosion if corrosive gas is being transported. However, the existing rules do not prescribe operators continually or periodically monitor the gas stream for the introduction of corrosive constituents through system modifications, gas supply changes, upset conditions, or other changes. This could result in operators not identifying internal corrosion if an initial assessment did not identify the presence of corrosive gas. Accordingly, PHMSA has determined that additional requirements are needed to ensure that operators effectively monitor their gas stream quality to identify if, and when, corrosive gas is being transported and mitigate deleterious gas stream constituents (*e.g.,* contaminants or liquids).

Therefore, this final rule adds a new § 192.478 to require onshore gas transmission operators monitor for known deleterious gas stream constituents and evaluate gas monitoring data once every calendar year, not to exceed a period of 15 months. Additionally, this final rule adds a requirement for onshore gas transmission operators to review their internal corrosion monitoring and mitigation program annually, not to exceed 15 months, and adjust the program as necessary to mitigate the presence of deleterious gas stream constituents. These requirements are in addition to the existing requirements to check coupons or perform other methods to monitor for the actual

Requirement of Valve Installation and Minimum Rupture Detection Standards,'' 87 FR 20940 (Apr. 8, 2022) (identifying an effective date in October 2022) (Valve Installation Final Rule). The amendatory text at the end of this final rule, therefore, reflects the text of § 192.18 as it will be revised when the Valve Installation Final Rule becomes effective.

presence of internal corrosion in the case of transporting a known corrosive gas stream. The new § 192.478 does not apply to gas gathering pipelines or distribution mains.

Section 192.485 Remedial Measures: Transmission Lines

Section 192.485 prescribes requirements for operators to perform remedial measures to address general corrosion and localized corrosion pitting in transmission pipelines. For such conditions, the requirements specify that an operator may determine the strength of pipe based on actual remaining wall thickness by using the procedure in ASME/ANSI B31G or the procedure in AGA Pipeline Research Committee Project PR 3–805 (RSTRENG). PHMSA has determined that additional requirements are needed beyond ASME/ANSI B31G and RSTRENG to ensure such calculations have a sound basis and has revised § 192.485(c) to specify that an operator must calculate the remaining strength of the pipe in accordance with § 192.712, which prescribes important aspects such as pipe and material properties, assumptions allowed when data is unknown, accounting for uncertainties, and recordkeeping requirements.

Section 192.613 Continuing Surveillance

Extreme weather and natural disasters can affect the safe operation of a pipeline. Accordingly, this final rule revises § 192.613 to require operators to perform inspections after these events and take appropriate remedial actions.

Section 192.710 Transmission Lines: Assessments Outside of High Consequence Areas

Section 192.710 prescribes requirements for the periodic assessment of certain pipelines outside of HCAs. In the NPRM, PHMSA proposed for operators to use the non-HCA repair criteria being finalized in this rule if they performed an assessment on a non-HCA pipeline and discovered an anomaly requiring repair. However, in splitting the rulemaking, PHMSA finalized the assessment requirement in the 2019 Gas Transmission Final Rule but did not incorporate regulatory text establishing the corresponding repair criteria. Therefore, in this final rule, PHMSA has revised the assessment requirement at § 192.710 to require operators to use the repair criteria finalized in this rulemaking if anomalies are discovered during these assessments.

Section 192.711 Transmission Lines: General Requirements for Repair Procedures

Section 192.711 prescribes general requirements for repair procedures. For non-HCA segments, the existing regulations required that operators make permanent repairs as soon as feasible. However, no specific repair criteria were detailed, and no specific timeframe or pressure reduction requirements were provided. PHMSA has determined that more specific repair criteria are needed for pipelines not covered under the integrity management regulations. Such repair criteria will help to maintain safety in a consistent manner in Class 1 through Class 4 locations that may have significant populations but that are not HCAs. Accordingly, this final rule amends paragraph (b)(1) of § 192.711 to require operators remediate specific conditions, as defined in § 192.714, on non-HCA gas transmission pipelines. Paragraph (b)(1) retains the existing requirement that operators must repair anomalies on gathering pipelines regulated in accordance with § 192.9 as soon as feasible.

Section 192.712 Analysis of Predicted Failure Pressure and Critical Strain Levels

In the 2019 Gas Transmission Rule, PHMSA updated and codified minimum standards for determining the predicted failure pressure of pipelines containing anomalies or defects associated with corrosion metal loss and cracks. In this final rule, PHMSA is revising the repair criteria for gas transmission pipelines, including for dents. Some of the revised dent repair criteria allow operators to determine critical strain levels for dents and defer repairs if critical strain levels are not exceeded. As such, PHMSA has established minimum standards for operators to calculate critical strain levels in pipe with dent anomalies or defects and has included those standards in a new paragraph (c) of § 192.712. The title of this section has also been updated to reflect this addition. PHMSA has also provided reassessment schedules for engineering critical assessments that operators perform to determine maximum reevaluation intervals to ensure that anomalies do not grow to critical sizes.

Section 192.714 Transmission Lines: Permanent Field Repair of Imperfections and Damages

Section 192.713 prescribes requirements for the permanent repair of pipeline imperfections or damage that impairs the serviceability of steel transmission pipelines operating at or above 40 percent of SMYS. PHMSA has determined that more explicit requirements are needed in § 192.714 to identify criteria for the severity of imperfections or damage that must be repaired, and to identify the timeframe within which repairs must be made for pipelines in all class locations that are not in HCAs. Pipelines not in HCAs can still have significant populations that could be harmed by a pipeline leak or rupture. As such, PHMSA has determined that repair criteria should apply to any onshore transmission pipeline not covered under the IM regulations in subpart O. PHMSA believes that establishing these non-HCA segment repair conditions for Class 1 locations through Class 4 locations are important because, even though they are not within HCAs, these locations could be in highly populated areas and are not without consequence to public safety and the environment.

Accordingly, this final rule creates a new § 192.714 to establish repair criteria for immediate, 2-year, and monitored conditions that the operator must remediate or monitor to ensure pipeline safety. PHMSA is using the same criteria as it is issuing for HCAs, except conditions for which a 1-year response is required in HCAs will require a 2-year response in non-HCA pipeline segments so that operators can allocate their resources to HCAs on a higher-priority basis. Additionally, PHMSA is prescribing more explicit requirements for the *in situ* evaluation of cracks and crack-like defects using in-the-ditch tools whenever required, such as when an ILI, SCCDA, pressure test failure, or other assessment identifies anomalies that suggest the presence of such defects.

Section 192.911 What are the elements of an integrity management program?

Paragraph (k) of § 192.911 requires that IM programs include a MOC process as outlined in ASME/ANSI B31.8S, section 11. PHMSA has determined that specific attributes and features of the MOC process that are currently specified in ASME/ANSI B31.8S, section 11, should be codified directly within the text of subpart O for HCAs to make the requirements readily available to all operators of onshore gas transmission pipelines. This change is consistent with the new paragraph (d) in § 192.13 for all onshore transmission pipelines.

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

Section 192.917 requires that operators with IM programs for covered pipeline segments identify potential threats to pipeline integrity and use the threat identification in their integrity program. This performance-based process includes requirements to identify threats to which the pipeline is susceptible, collect data for analysis, and perform a risk assessment. The regulations include special requirements for operators to address plastic pipe and particular threats, such as third-party damage and manufacturing and construction defects.

As specified in § 192.907(a), PHMSA expected operators to start with a framework for IM, which would later evolve into a more detailed and comprehensive program, and expected that an operator would continually improve its IM program as it learned more about the process and about the material condition of its pipelines through integrity assessments. PHMSA elaborated on this philosophy in the 2003 IM rule.[52]

Even though the IM regulations have been in effect since 2004, PHMSA still finds certain operators have poorly developed IM programs. The clarifications and additional specificity adopted in this final rule, with respect to the processes an operator must use in implementing the threat identification, risk assessment, and preventive and mitigative measure program elements, reflect PHMSA's expectation regarding the degree of progress operators should be making, or should have made, during the first 10 years of the implementation of the IM regulations.

The current IM regulations incorporate by reference ASME/ANSI B31.8S to require that operators implement specific attributes and features of the threat identification, data analysis, and risk assessment process in their IM programs. In this final rule, PHMSA is amending § 192.917 to insert certain critical features of ASME/ANSI B31.8S directly into the regulatory text. PHMSA is specifying several pipeline attributes that must be included in pipeline risk assessments and is explicitly requiring that operators integrate analyzed information and ensure that data is verified and validated to the maximum extent practical. To the degree that subjective data from SMEs must be used, PHMSA is requiring that an operator's program account and compensate for uncertainties in the risk model used and the data used in the operator's risk assessment. PHMSA is also in this final rule revising the non-exhaustive list of data to be collected for clarity or to eliminate redundant language.

PHMSA will note that in its advisory bulletin on the verification of records that ''verifiable'' records are those in which information is confirmed by other complementary, but separate, documentation. Such records might include contract specifications for a pressure test of a line segment complemented by field logs or purchase orders with pipe specifications verified by metallurgical tests of coupons pulled from the same pipe segment.

Additionally, PHMSA is clarifying the performance-based risk assessment aspects of the IM regulations in this final rule by specifying that operators must perform risk assessments that are adequate for evaluating the effects of interacting threats; determine additional P&M measures needed; analyze how a potential failure could affect HCAs, including the consequences of the entire worst-case incident scenario from initial failure to incident termination; identify the contribution to risk of each risk factor, or each unique combination of risk factors that interact or simultaneously contribute to risk at a common location; account for, and compensate for, uncertainties in the model and the data used in the risk assessment; and evaluate risk reduction associated with candidate risk reduction activities, such as P&M measures.

In consideration of NTSB recommendation P–11–18, PHMSA is adopting regulations that require operators to validate their risk models considering incident, leak, and failure history and other historical information. These features are currently requirements because they are incorporated by reference in ASME/ANSI B31.8S. However, PHMSA has found that provisions incorporated directly into its regulatory text have higher levels of compliance. The final rule also amends the requirements for plastic pipe to provide specific examples of integrity threats for plastic pipe that must be addressed.

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

This final rule incorporates by reference NACE SP0206–2006, ''Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas,'' for addressing ICDA, and NACE SP0204–2008, ''Stress Corrosion Cracking Direct Assessment,'' for addressing SCCDA. Accordingly, PHMSA has revised § 192.923(b)(2) and (3) to require operators comply with these standards.

Section 192.927 What are the requirements for using internal Corrosion Direct Assessment (ICDA)?

Section 192.927 specifies requirements for gas transmission pipeline operators who use ICDA for IM assessments. The requirements in § 192.927 were promulgated before NACE SP0206–2006 was published and require that operators follow ASME/ANSI B31.8S provisions related to ICDA. PHMSA has reviewed NACE SP0206–2006 and finds that it is more comprehensive and rigorous than either § 192.927 or ASME/ANSI B31.8S in many respects. Therefore, PHMSA is incorporating NACE SP0206–2006 into the regulations for the performance of ICDA and is establishing additional requirements for addressing covered segments within the technical process defined by the NACE standard.

This final rule requires that operators perform two direct examinations within each covered segment the first time ICDA is performed. These examinations are in addition to those required to comply with the NACE standard. The additional examinations are consistent with the current requirement in § 192.927(c)(5)(ii) that operators apply more restrictive criteria when conducting ICDA for the first time and are intending to verify, within the HCA, that the results of applying the process of NACE SP0206–2006 for the ICDA are acceptable. Applying the process for NACE SP0206–2006 requires more precise knowledge of the pipeline orientation (particularly slope) than operators may have in many cases. Conducting examinations within the HCA during the first application of ICDA will verify that applying the ICDA process provides an operator with adequate information about the covered segment. Operators who identify internal corrosion on these additional examinations, even though excavations at locations determined using NACE SP0206–2006 did not identify any internal corrosion, will know that improvements are needed to their knowledge of pipeline orientation. In addition, operators will know they need other adjustments to their application of the NACE standard to the covered segment for using ICDA in the future. Section 192.927(b) and (c) are revised in this final rule to address these issues.

PHMSA notes that, for these requirements, operators are prohibited from using assumed pipeline or operational data. Any data an operator

[52] ''Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines)''; 68 FR 69778 (Dec. 15, 2003). See 68 FR 69789.

uses for its ICDA process should be based on known information, such as the pipeline route, the pipeline diameter, and pipeline flow inputs and outputs. Operators can choose to base their ICDA process on data that is more conservative than their known pipeline or operational data.

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

Section 192.929 specifies requirements for gas transmission pipeline operators who use SCCDA for IM assessments. The requirements in § 192.929 were promulgated before NACE Standard Practice SP0204–2008 was published, and the standard requires that operators follow Appendix A3 of ASME/ANSI B31.8S. That appendix provides some guidance for conducting SCCDA but is limited to SCC that occurs in high-pH environments. Experience has shown that pipelines can also experience SCC degradation in areas where the surrounding soil has a pH near neutral (referred to as near-neutral SCC). NACE SP0204–2008 addresses near-neutral SCC as well as high-pH SCC. NACE SP0204–2008 also provides technical guidelines and process requirements that are both more comprehensive and rigorous for conducting SCCDA than § 192.929 or ASME/ANSI B31.8S.

Since NACE SP0204–2008 provides comprehensive guidelines on conducting SCCDA and is more comprehensive in scope than Appendix A3 of ASME/ANSI B31.8S, PHMSA has concluded the quality and consistency of SCCDA conducted under IM requirements would be improved by requiring operators to use NACE SP0204–2008. The final rule accomplishes this.

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

Section 192.933 specifies injurious anomalies and defects that operators must remediate and the timeframes within which such remediation must occur. PHMSA determined that the existing regulations for repair criteria had gaps, as some injurious anomalies and defects were not listed as requiring remediation in a timely manner commensurate with their seriousness. To remedy this, in this final rule, PHMSA is designating the following types of defects as immediate conditions: (1) anomalies where the metal loss is greater than 80 percent of nominal wall thickness; (2) metal loss anomalies with a predicted failure pressure less than or equal to 1.1 times the MAOP; (3) a topside dent that has metal loss, cracking, or a stress riser; (4) anomalies where there is an indication of metal loss affecting certain longitudinal seams; and (5) cracks or crack-like anomalies meeting specified criteria.

The final rule also designates the following types of defects as 1-year conditions: (1) smooth topside dents with a depth greater than 6 percent of the pipeline diameter; (2) dents greater than 2 percent of the pipeline diameter that are located at a girth weld or spiral seam weld; (3) a bottom-side dent that has metal loss, cracking, or a stress riser; (4) metal loss anomalies where a calculation of the remaining strength of the pipe shows a predicted failure pressure ratio less than or equal to 1.39 for Class 2 locations, and 1.50 for Class 3 locations and Class 4 locations; (5) anomalies where there is metal loss that is at a crossing of another pipeline, is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld, and that has a predicted failure pressure less than 1.39 in Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, and less than 1.50 times the MAOP in all other Class 2 locations and all Class 3 and 4 locations; (6) anomalies where there is metal loss affecting a longitudinal seam; and (7) any indications of cracks or crack-like defects other than those listed as an immediate condition.

In this final rule, PHMSA is also adding requirements for addressing regulatory gaps related to the methods for calculating predicted failure pressure if metal loss exceeds 80 percent of wall thickness; time-sensitive integrity threats including corrosion affecting a longitudinal seam, especially those associated with seam types that are known to be susceptible to latent manufacturing defects, such as the failed pipe at San Bruno,[53] and selective seam weld corrosion; and the fact that the current regulations do not list SCC as an immediate condition even though it is listed in ASME/ANSI B31.8S as an immediate repair condition.

With respect to SCC, PHMSA has incorporated repair criteria to specify that operators must use engineering assessment techniques specified in § 192.712 to evaluate if cracks or crack-like anomalies should be categorized as an ''immediate'' condition, a ''1-year'' condition, or a ''monitored'' condition. PHMSA believes that this will help address NTSB recommendation P–12–3, which resulted from the investigation of the Enbridge accident near Marshall, MI.[54] Although the NTSB recommendation was specifically made for hazardous liquid pipelines regulated under part 195, SCC can affect gas transmission pipelines regulated under part 192 as well.

The current regulations do not include 1-year conditions for metal loss anomalies. For non-immediate conditions, the regulations direct operators to use Figure 4 in ASME/ANSI B31.8S to determine the repair criteria for metal loss anomalies that do not meet the ''immediate'' threshold. To address this gap, PHMSA is including certain metal loss anomalies in the list of 1-year conditions. These changes make the gas transmission repair criteria more consistent with the hazardous liquid repair criteria at 49 CFR 195.452(h).

PHMSA is also incorporating safety factors commensurate with the class location in which the pipeline is located to make 1-year conditions anomalies where the predicted failure pressure is less than or equal to 1.39 times MAOP in Class 2 locations, and 1.50 times MAOP in Class 3 and Class 4 locations in HCAs. Operators must continue to use ASME/ANSI B31.8S, Figure 4 for corrosion metal loss anomalies in Class 1 locations.

Additionally, the NTSB recommended that PHMSA revise the ''discovery of condition'' at 49 CFR 195.452(h)(2) to require, in cases where a determination about pipeline threats has not been obtained within 180 days following the date of inspection, that pipeline operators notify PHMSA and provide an expected date when adequate information will become available.[55] PHMSA incorporated this NTSB recommendation into §§ 195.416(f) and 195.452(h)(2) of the ''Safety of Hazardous Liquid Pipelines'' final rule, which was published on October 1, 2019.[56]

Although the NTSB made the recommendation for hazardous liquid pipelines regulated under part 195, the issue applies to gas transmission pipelines regulated under part 192 as well. Accordingly, PHMSA has

[53] These seam types include seams formed by direct current, low- or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with § 192.712(d), is less than 1.25 times the MAOP.

[54] See NTSB Recommendation P–12–3, available at *https://www.ntsb.gov/_layouts/ntsb.recsearch/Recommendation.aspx?Rec=P-12-003.*

[55] NTSB Recommendation P–12–4, available at *https://www.ntsb.gov/safety/safety-recs/_layouts/ntsb.recsearch/Recommendation.aspx?Rec=P-12-004.*

[56] See 84 FR 52260.

amended paragraph (b) of § 192.933 to require that operators notify PHMSA whenever the operator cannot obtain sufficient information to determine if a condition presents a potential threat to the integrity of the pipeline within 180 days of completing the assessment.

PHMSA is also finalizing requirements for the *in situ* evaluation of cracks and crack-like defects using in-the-ditch tools whenever an operator discovers conditions that need to be repaired, such as when an ILI, an SCCDA, a pressure test failure, or another assessment identifies such anomalies. This applies to IM pipelines the same requirement adopted in § 192.714(g) for non-IM pipelines.

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

Section 192.935 requires an operator to take additional measures beyond those already required by part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in an HCA. An operator must conduct a risk analysis to identify the additional measures to protect the HCA and improve public safety. As discussed earlier, PHMSA is amending § 192.917 to clarify the guidance for risk analyses operators use to evaluate and select additional P&M measures. This final rule also adds specific enhanced measures for operators to use for managing internal and external corrosion in HCAs and expands the list of P&M measures operators must consider when providing for public safety.

Specifically, operators must explicitly consider the following P&M measures:

(i) Correcting the root causes of past incidents in order to prevent recurrence;

(ii) O&M processes that maintain safety and the pipeline MAOP;

(iii) Adequate resources for the successful execution of these activities within the required timeframe;

(iv) Pressure transmitters that communicate with the pipeline control center on both sides of automatic shut-off valves and remote-control valves;

(v) Additional right-of-way patrols;

(vi) Hydrostatic tests in areas where pipeline material has quality issues or records that are not traceable, verifiable, and complete;

(vii) Tests to determine unknown material, mechanical, or chemical properties that are needed to ensure pipeline integrity or substantiate MAOP, including material property tests from removed pipe that is representative of the in-service pipeline;

(viii) The re-coating of damaged, poorly performing, or disbonded coatings, and

(ix) Additional depth-of-cover surveys at roads, streams, and rivers, among other areas.

These P&M measures do not alter the fundamental requirement for operators to identify and implement P&M measures; rather, they provide additional guidance and clarify PHMSA's expectations with this important aspect of IM.

Section 29 of the 2011 Pipeline Safety Act requires operators to consider seismicity when evaluating threats. In the 2019 Gas Transmission Rule, PHMSA revised § 192.917 to include seismicity as a potential threat for operators to identify and evaluate. In this final rule, PHMSA is revising this section to require operators consider the seismicity of the area when evaluating additional P&M measures against the threat of outside force damage.

Section 192.941 What is a low stress reassessment?

Section 192.941 specifies that, to address the threat of external corrosion on cathodically protected pipe in an HCA segment, an operator must perform an electrical survey (*i.e.,* with an indirect examination tool or method) at least every 7 years. In this final rule, PHMSA is replacing the term ''electrical survey'' with ''indirect assessment'' to accommodate other techniques that are comparably effective.

V. Standards Incorporated by Reference

A. Summary of New and Revised Standards

Consistent with the amendments in this document, PHMSA is incorporating by reference into the PSR several standards as described below. Some of these standards are already incorporated by reference into the PSR and are being extended to other sections of the regulations. Other standards provide a technical basis for corresponding regulatory changes in this final rule.

• NACE Standard Practice 0204–2008, ''Stress Corrosion Cracking (SCC) Direct Assessment Methodology'' (Sept. 18, 2008).

This standard addresses the situation in which a portion of a pipeline has been identified as an area of interest with respect to SCC based on its history, operations, and risk assessment process, and it has been decided that direct assessment is an appropriate approach for integrity assessment. The incorporation of this standard into the PSR would provide guidance for managing SCC through the selection of potential pipeline segments, selecting dig sites within those segments, inspecting the pipe, collecting and analyzing data during the dig, establishing a mitigation program, defining the re-evaluation interval, and evaluating the effectiveness of the SCCDA process.

• NACE Standard Practice 0206–2006, ''Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas'' (DG–ICDA) (Dec. 1, 2006).

This standard practice formalizes an internal corrosion direct assessment method (DG–ICDA) that can be used to help ensure pipeline integrity for pipelines carrying normally dry natural gas. The method is applicable to natural gas pipelines that normally carry dry gas but that may suffer from infrequent, short-term upsets of liquid water (or other electrolyte). This standard is intended for use by pipeline operators and others who manage pipeline integrity. The basis of DG–ICDA is a detailed examination of locations along a pipeline where water would first accumulate and provides information about the downstream condition of the pipeline. If the locations along a length of pipe most likely to accumulate water have not corroded, other downstream locations less likely to accumulate water may be considered free from corrosion. The presence of extensive corrosion found at many locations during the evaluation suggests that the transported gas was not normally dry, and this standard would not be considered applicable.

• ASME/ANSI B31.8S–2004, ''Supplement to B31.8 on Managing System Integrity of Gas Pipelines'' (Jan. 14, 2005).

This standard covers onshore gas pipeline systems constructed with ferrous materials, including pipe, valves, appurtenances attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. ASME/ANSI B31.8S is specifically designed to provide the operator with the information necessary to develop and implement an effective IM program using proven industry practices and processes. Effective system management can decrease repair and replacement costs, prevent malfunctions, and minimize system downtime.

The incorporation by reference of ASME/ANSI B31.8S–2004 was approved for §§ 192.921 and 192.937 as of January 14, 2004. That approval is unaffected by the section revisions in this final rule.

• ANSI/NACE Standard Practice 0502–2010, ''Pipeline External Corrosion Direct Assessment Methodology'' (June 24, 2010).

This standard covers the NACE external corrosion direct assessment (ECDA) process, which assesses and reduces the impact of external corrosion on pipeline integrity. ECDA is a continuous-improvement process providing the advantages of locating areas where defects can form in the future, not just areas where defects have already formed, thereby helping to prevent future external corrosion damage. This standard covers the four components of ECDA: Pre-Assessment, Indirect Inspections, Direct Examinations, and Post-Assessment.

The incorporation by reference of ANSI/NACE Standard Practice 0502–2010 was approved for §§ 192.923, 192.925, 192.931, 192.935, and 192.939 as of March 6, 2015. That approval is unaffected by the section revisions in this final rule.

The incorporation by reference of R–STRENG and ASME/ANSI B31G in certain sections of this rule was approved July 1, 2020, and remains unaffected by the revisions in this final rule.

B. Availability of Standards Incorporated by Reference

PHMSA currently incorporates by reference into 49 CFR parts 192, 193, and 195 all or parts of more than 80 standards and specifications developed and published by standard developing organizations (SDO). In general, SDOs update and revise their published standards every 2 to 5 years to reflect modern technology and best technical practices.

The National Technology Transfer and Advancement Act of 1995 (Pub. L. 104–113; NTTAA) directs Federal agencies to use standards developed by voluntary consensus standards bodies in lieu of government-written standards whenever possible. Voluntary consensus standards bodies develop, establish, or coordinate technical standards using agreed-upon procedures. In addition, the Office of Management and Budget (OMB) issued Circular A–119 to implement section 12(d) of the NTTAA relative to the utilization of consensus technical standards by Federal agencies.[57] This circular provides guidance for agencies participating in voluntary consensus standards bodies and describes procedures for satisfying the reporting requirements in the NTTAA.

Accordingly, PHMSA has the responsibility for determining, via petitions or otherwise, which currently referenced standards should be updated, revised, or removed, and which standards should be added to the PSR. Revisions to materials incorporated by reference in the PSR are handled via the rulemaking process, which allows for the public and regulated entities to provide input. During the rulemaking process, PHMSA must also obtain approval from the Office of the Federal Register to incorporate by reference any new materials.

Pursuant to 49 U.S.C. 60102(p), PHMSA may not issue PSR amendments that incorporate by reference any documents or portions thereof unless the documents or portions thereof are made available to the public, free of charge. Further, the Office of the Federal Register issued a rulemaking on November 7, 2014, revising 1 CFR 51.5(b) to require that agencies detail in the preamble of a final rulemaking the ways the materials it incorporates by reference are reasonably available to interested parties, and how interested parties can obtain those materials.[58]

To meet its statutory obligation for this rulemaking, PHMSA negotiated agreements with SDOs to provide free online access to standards that are incorporated by reference or proposed to be incorporated by reference. PHMSA will also provide individual members of the public temporary access to any standard that is incorporated by reference. Requests for access can be sent to the following email address: *phmsaphpstandards@dot.gov;* please include your phone number, physical address, and an email address and PHMSA will respond within 5 business days and provide access to the standard. PHMSA also notes that standards incorporated by reference in the PSR can be obtained from the organization developing each standard. Section 192.7 provides the contact information for each of those standard-developing organizations.

VI. Regulatory Analysis and Notices

A. Statutory/Legal Authority for This Rulemaking

This final rule is published under the existing authorities of the Secretary of Transportation delegated to the PHMSA Administrator pursuant to 49 CFR 1.97. Among the statutory authorities delegated to PHMSA are section 60102 of the Federal Pipeline Safety Statutes (49 U.S.C. 60101 *et seq.*) (authorizing issuance of regulations governing design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities) and section 28 of the Mineral Leasing Act, as amended (30 U.S.C. 185(w)(3)). For a complete listing of authorities, see 49 CFR 1.97.

B. Executive Order 12866 and DOT Regulatory Policies and Procedures

Executive Order 12866 (''Regulatory Planning and Review'')[59] requires that agencies ''should assess all costs and benefits of available regulatory alternatives, including the alternative of not regulating.'' Agencies should consider quantifiable measures and qualitative measures of costs and benefits that are difficult to quantify. Further, Executive Order 12866 requires that agencies ''should maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity), unless a statute requires another regulatory approach.'' Similarly, DOT Order 2100.6A (''Rulemaking and Guidance Procedures'') requires that regulations issued by PHMSA and other DOT Operating Administrations should consider an assessment of the potential benefits, costs, and other important impacts of the proposed action and should quantify (to the extent practicable) the benefits, costs, and any significant distributional impacts, including any environmental impacts. The Federal Pipeline Safety Statutes at 49 U.S.C. 60102(b)(5) further authorize only those safety requirements whose benefits (including safety and environmental benefits) have been determined to justify their costs.

This action has been determined to be significant under Executive Order 12866. It is also considered significant under DOT Order 2100.6A because of significant congressional, State, industry, and public interest in pipeline safety. The final rule has been reviewed by the Office of Management and Budget in accordance with Executive Order 12866 and is consistent with the requirements of Executive Order 12866, 49 U.S.C. 60102(b)(5), and DOT Order 2100.6. The Office of Information and Regulatory Affairs (OIRA) has not designated this rule as a ''major rule'' as defined by the Congressional Review Act (5 U.S.C. 801 *et seq.*).

Executive Order 12866 and DOT Order 2100.6A also require PHMSA to provide a meaningful opportunity for public participation, which also reinforces requirements for notice and comment under the Administrative Procedure Act (5 U.S.C. 551 *et seq.*). Therefore, in the NPRM, PHMSA sought public comment on its proposed revisions to the PSR and the preliminary cost and benefit analyses in the PRIA, as

[57] 81 FR 4673 (Jan. 27, 2016).

[58] 79 FR 66278.

[59] 58 FR 51735 (Oct. 4, 1993).

well as any information that could assist in quantifying the costs and benefits of this rulemaking. Those comments are addressed in this final rule, and additional discussion about the costs and benefits of the final rule are provided within the RIA posted in the rulemaking docket.

The table below summarizes the annualized costs for the provisions in the final rule. These estimates reflect the timing of the compliance actions taken by operators and are annualized, where applicable, over 20 years and discounted using rates of 3 percent and 7 percent. PHMSA estimates incremental costs for the final requirements in section 5 of the RIA. The costs of this final rule reflect MOC process improvements, additional corrosion control requirements, programmatic changes related to inspections following extreme weather events, and compliance with the revised repair criteria. PHMSA finds that the other final rule requirements will not result in an incremental cost. PHMSA estimates the annualized cost of this rule is $16.7 million at a 7 percent discount rate.

TABLE 1—ANNUALIZED COST OF THE FINAL RULE, YEAR 1–YEAR 20

[$2019 USD thousands]

Provision	Discount rate	
	3%	7%
Integrity Management Process Improvements *	$0	$0
Management of Change Process Improvements	1,194	1,223
Corrosion Control	8,662	8,998
Extreme Weather	55	78
Repair Criteria	2,725	6,357
Total	12,637	16,656

* No incremental costs are estimated for this topic area.

The benefits of the final rule consist of improved safety and avoided environmental harms (including greenhouse gas emissions) from reduction of risk of incidents on natural gas pipelines and will depend on the degree to which compliance actions result in additional safety measures, relative to the baseline, and the effectiveness of these measures in preventing or mitigating future pipeline releases or other incidents. PHMSA changed its benefit analysis approach for the RIA relative to the PRIA. The PRIA quantified and monetized the NPRM's benefits, while the RIA does not monetize this final rule's benefits. PHMSA chose not to monetize benefits in the RIA based on the public comments received in response to the PRIA and the uncertainty associated with quantifying changes in incident rates that can be explicitly attributed to the final rule's provisions.

For more information, please see the RIA posted in the rulemaking docket.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) requires agencies to prepare a Final Regulatory Flexibility Analysis (FRFA) for any final rule subject to notice-and-comment rulemaking under the APA unless the agency head certifies that the rule will not have a significant economic impact on a substantial number of small entities. This final rule was developed in accordance with Executive Order 13272 (''Proper Consideration of Small Entities in Agency Rulemaking'') [60] to promote compliance with the Regulatory Flexibility Act and to ensure that the potential impacts of the rulemaking on small entities has been properly considered.

PHMSA prepared a FRFA, which is available in the docket for the rulemaking. In it, PHMSA certifies that the rule will not have a significant impact on a substantial number of small entities.

D. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

PHMSA analyzed this final rule per the principles and criteria in Executive Order 13175 (''Consultation and Coordination with Indian Tribal Governments'') [61] and DOT Order 5301.1 (''Department of Transportation Policies, Programs, and Procedures Affecting American Indians, Alaska Natives, and Tribes''). Executive Order 13175 requires agencies to assure meaningful and timely input from Tribal Government representatives in the development of rules that significantly or uniquely affect Tribal communities by imposing ''substantial direct compliance costs'' or ''substantial direct effects'' on such communities or the relationship and distribution of power between the Federal Government and Tribes.

PHMSA assessed the impact of the rulemaking and determined that it would not significantly or uniquely affect Tribal communities or Tribal governments. The rulemaking's regulatory amendments are facially neutral and would have broad, national scope; PHMSA, therefore, does not expect this rulemaking to significantly or uniquely affect Tribal communities, much less impose substantial compliance costs on Native American Tribal governments or mandate Tribal action. And insofar as PHMSA expects the rulemaking will improve transmission pipeline safety and environmental risks, PHMSA does not expect it would entail disproportionately high adverse risks for Tribal communities. PHMSA also received no comments alleging ''substantial direct compliance costs'' or ''substantial direct effects'' on Tribal communities and Governments. For these reasons, PHMSA has determined the funding and consultation requirements of Executive Order 13175 and DOT Order 5301.1 do not apply.

E. Paperwork Reduction Act

Under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*), no person is required to respond to an information collection unless it has been approved by OMB and displays a valid OMB control number. Pursuant to implementing regulations at 5 CFR 1320.8(d), PHMSA is required to provide interested members of the public and affected agencies with an opportunity to comment on information collection and recordkeeping requests.

On April 8, 2016, PHMSA published an NPRM seeking public comments on proposed revisions of the PSR

[60] 68 FR 7990 (Feb. 19, 2003).

[61] 65 FR 67249 (Nov. 6, 2000).

applicable to the safety of gas transmission pipelines and gas gathering pipelines. Based on the provisions in the NPRM, PHMSA proposed corresponding changes to information collections. PHMSA determined it would be more effective to first advance a rulemaking that focused on the mandates from the 2011 Pipeline Safety Act and subsequently split out the other provisions contained in the NPRM into three separate rules. As such, in this rulemaking, PHMSA has removed all references to the changes in the information collections covered in those other rulemakings. PHMSA will submit information collection revision requests to OMB based on the requirements contained within this final rule.

PHMSA estimates that the proposals in this final rule will involve new and amended information collections as described below. The following information is provided for each information collection: (1) title of the information collection; (2) OMB control number; (3) current expiration date; (4) type of request; (5) abstract of the information collection activity; (6) description of affected public; (7) estimate of total annual reporting and recordkeeping burden; and (8) frequency of collection. Relevant information collections consist of the following:

1. Title: Record Keeping Requirements for Gas Pipeline Operators.

OMB Control Number: 2137–0049.

Current Expiration Date: 3/31/2025.

Abstract: A person owning or operating a natural gas pipeline facility is required to maintain records, make reports, and provide information to the Secretary of Transportation upon request. Based on the proposed revisions in this final rule, 16 new recordkeeping requirements are being added to the pipeline safety regulations for owners and operators of gas transmission pipelines. PHMSA expects these new mandatory recordkeeping requirements to result in 1,902 responses and 9,530 burden hours.

Affected Public: Gas Transmission Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 3,863,374.

Total Annual Burden Hours: 1,686,560.

Frequency of Collection: On occasion.

2. Title: Notification Requirements for Gas Transmission Pipelines.

OMB Control Number: 2137–0636.

Current Expiration Date: 01/31/2023.

Abstract: A person owning or operating a natural gas pipeline facility is required to provide information to the Secretary of Transportation at the Secretary's request in accordance with 49 U.S.C. 60117. The regulations in 49 CFR part 192 require operators to make various notifications upon the occurrence of certain events. Based on the proposed revisions in this final rule, 6 new notification requirements are being added to the PSR for owners and operators of gas transmission pipelines. PHMSA expects these revisions to result in 268 additional responses and 290 additional burden hours for this information collection. These mandatory notification requirements are necessary to ensure safe operation of transmission pipelines, ascertain compliance with gas pipeline safety regulations, and to provide a background for incident investigations.

Affected Public: Gas Transmission Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 990.

Total Annual Burden Hours: 1,360.

Frequency of Collection: On occasion.

3. Title: Annual Reports for Gas Pipeline Operators

OMB Control Number: 2137–0522.

Current Expiration Date: 3/31/2025.

Abstract: This information collection covers the collection of annual report data from natural gas pipeline operators. PHMSA is revising the Gas Transmission and Gas Gathering Annual Report (form PHMSA F7 100.2–1) to collect more granular data on conditions being repaired outside of HCA segments. Operators currently provide the number of anomalies outside of HCAs based on assessment methods, however, PHMSA requires operators to further categorize the data in accordance with 49 CFR 192.713. Based on the proposed revisions, PHMSA estimates that it will take an additional 30 minutes per report to include the newly required data—increasing the burden for completing each annual report to 47.5 hours. This change results in an overall burden increase of 905 hours for this information collection.

Affected Public: Natural Gas Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 3,053.

Total Annual Burden Hours: 95,521.

Frequency of Collection: On occasion.

Requests for copies of these information collections should be directed to Angela Hill or Cameron Satterthwaite, Office of Pipeline Safety (PHP–30), Pipeline Hazardous Materials Safety Administration (PHMSA), 2nd Floor, 1200 New Jersey Avenue, SE, Washington, DC 20590–0001, Telephone (202) 366–4595.

F. Unfunded Mandates Reform Act of 1995

The Unfunded Mandates Reform Act (2 U.S.C. 1501 *et seq.*) requires agencies to assess the effects of Federal regulatory actions on State, local, and Tribal governments, and the private sector. For any NPRM or final rule that includes a Federal mandate that may result in the expenditure by State, local, and Tribal governments, in the aggregate, or by the private sector of $100 million or more in 1996 dollars in any given year, the agency must prepare, amongst other things, a written statement that qualitatively and quantitatively assesses the costs and benefits of the Federal mandate.

As explained in the RIA, PHMSA determined that this final rule does not impose enforceable duties on State, local, or Tribal governments or on the private sector of $100 million or more (in 1996 dollars) in any one year. A copy of the RIA is available for review in the docket.

G. National Environmental Policy Act

The National Environmental Policy Act of 1969 (42 U.S.C. 4321 *et seq.,* NEPA), requires Federal agencies to consider the consequences of major Federal actions and prepare a detailed statement on actions significantly affecting the quality of the human environment. The Council on Environmental Quality implementing regulations (40 CFR parts 1500–1508) require Federal agencies to conduct an environmental review considering (1) the need for the action, (2) alternatives to the action, (3) probable environmental impacts of the action and alternatives, and (4) the agencies and persons consulted during the consideration process. DOT Order 5610.1C (''Procedures for Considering Environmental Impacts'') establishes departmental procedures for evaluation of environmental impacts under NEPA and its implementing regulations.

PHMSA has completed its NEPA analysis. Based on the environmental assessment, PHMSA determined that an environmental impact statement is not required for this rulemaking because it will not have a significant impact on the human environment. The final EA and Finding of No Significant Impact have been placed into the docket addressing the comments received.

H. Executive Order 13132

PHMSA analyzed this final rule in accordance with Executive Order 13132 (''Federalism'').[62] Executive Order

[62] 64 FR 43255 (Aug.10, 1999).

13132 requires agencies to assure meaningful and timely input by State and local officials in the development of regulatory policies that may have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

The final rule does not have a substantial direct effect on the State and local governments, the relationship between the Federal Government and the States, or the distribution of power and responsibilities among the various levels of government. This rulemaking action does not impose substantial direct compliance costs on State and local governments. Section 60104(c) of the Federal Pipeline Safety Statutes prohibits certain State safety regulation of interstate pipelines. Under the Federal Pipeline Safety Statutes, States can augment pipeline safety requirements for intrastate pipelines regulated by PHMSA but may not approve safety requirements less stringent than those required by Federal law. A State may also regulate an intrastate pipeline facility that PHMSA does not regulate. In this instance, the preemptive effect of the final rule is limited to the minimum level necessary to achieve the objectives of the pipeline safety laws under which the final rule is promulgated. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply.

I. Executive Order 13211

Executive Order 13211 (''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'') [63] requires Federal agencies to prepare a Statement of Energy Effects for any ''significant energy action.'' Executive Order 13211 defines a ''significant energy action'' as any action by an agency (normally published in the **Federal Register**) that promulgates, or is expected to lead to the promulgation of, a final rule or regulation that (1)(i) is a significant regulatory action under Executive Order 12866 or any successor order and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy (including a shortfall in supply, price increases, and increased use of foreign supplies); or (2) is designated by the Administrator of the OIRA as a significant energy action.

This final rule is a significant action under Executive Order 12866; however, it is expected to have an annual effect on the economy of less than $100 million. Further, this action is not likely to have a significant adverse effect on the supply, distribution, or use of energy in the United States. The Administrator of OIRA has not designated the final rule as a significant energy action. For additional discussion of the anticipated economic impact of this rulemaking, please review the RIA posted in the rulemaking docket.

J. Privacy Act Statement

Anyone may search the electronic form of all comments received for any of our dockets. You may review DOT's complete Privacy Act Statement [64] at: *https://www.govinfo.gov/content/pkg/FR-2000-04-11/pdf/00-8505.pdf.*

K. Executive Order 13609 and International Trade Analysis

Executive Order 13609 (''Promoting International Regulatory Cooperation'') [65] requires agencies consider whether the impacts associated with significant variations between domestic and international regulatory approaches are unnecessary or may impair the ability of American business to export and compete internationally. In meeting shared challenges involving health, safety, labor, security, environmental, and other issues, international regulatory cooperation can identify approaches that are at least as protective as those that are or would be adopted in the absence of such cooperation. International regulatory cooperation can also reduce, eliminate, or prevent unnecessary differences in regulatory requirements.

Similarly, the Trade Agreements Act of 1979 (Pub. L. 96–39), as amended by the Uruguay Round Agreements Act (Pub. L. 103–465), prohibits Federal agencies from establishing any standards or engaging in related activities that create unnecessary obstacles to the foreign commerce of the United States. For purposes of these requirements, Federal agencies may participate in the establishment of international standards, so long as the standards have a legitimate domestic objective, such as providing for safety, and do not operate to exclude imports that meet this objective. The statute also requires consideration of international standards and, where appropriate, that they be the basis for U.S. standards.

PHMSA participates in the establishment of international standards to protect the safety of the American public. PHMSA has assessed the effects of the rulemaking and determined that it will not cause unnecessary obstacles to foreign trade.

L. Environmental Justice

DOT Order 5610.2(b) and Executive Orders 12898 (''Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations''),[66] 13985 (''Advancing Racial Equity and Support for Underserved Communities Through the Federal Government''),[67] 13990 (''Protecting Public Health and the Environment and Restoring Science To Tackle the Climate Crisis''),[68] and 14008 (''Tackling the Climate Crisis at Home and Abroad'') [69] require DOT operational administrations to achieve environmental justice as part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects, including interrelated social and economic effects, of their programs, policies, and activities on minority populations, low-income populations, and other underserved disadvantaged communities.

PHMSA has evaluated this final rule under DOT Order 5610.2(b) and the Executive Orders listed above and determined it would not cause disproportionately high and adverse human health and environmental effects on minority populations, low-income populations, and other underserved and disadvantaged communities. The rulemaking is facially neutral and national in scope; it is neither directed toward a particular population, region, or community, nor is it expected to adversely impact any particular population, region, or community. And insofar as PHMSA expects the rulemaking would reduce the safety and environmental risks associated with natural gas transmission pipelines, many of which are located in the vicinity of environmental justice communities,[70] PHMSA expects the regulatory amendments introduced by this final rule would reduce adverse human health and environmental risks for minority populations, low-income populations, and other underserved and other disadvantaged communities in the vicinity of those pipelines. Lastly, as

[63] 66 FR 28355 (May 18, 2001).

[64] 65 FR 19476 (Apr. 11, 2000).

[65] 77 FR 26413 (May 4, 2012).

[66] 59 FR 7629 (Feb. 16, 1994).

[67] 86 FR 7009 (Jan. 20, 2021).

[68] 86 FR 7037 (Jan. 20, 2021).

[69] 86 FR 7619 (Feb. 1, 2021).

[70] See Ryan Emmanuel, et al., ''Natural Gas Gathering and Transmission Pipelines and Social Vulnerability in the United States,'' 5:6 GeoHealth (June 2021), *https://agupubs.onlinelibrary.wiley.com/toc/24711403/2021/5/6* (concluding that natural gas gathering and transmission infrastructure is disproportionately sited in socially-vulnerable communities).

explained in the final EA, PHMSA expects that the regulatory amendments in this final rule will yield GHG emissions reductions, thereby reducing the risks posed by anthropogenic climate change to minority, low-income, underserved, and other disadvantaged populations and communities.

List of Subjects in 49 CFR Part 192

Corrosion control, Incorporation by reference, Installation of pipe in a ditch, Integrity management, Internal inspection device, Management of change, Pipeline safety, Repair criteria, Surveillance.

In consideration of the foregoing, PHMSA amends 49 CFR part 192 as follows:

PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

■ 1. The authority citation for part 192 continues to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5103, 60101 *et seq.,* and 49 CFR 1.97.

■ 2. In § 192.3:
■ a. Add definitions for ''Close interval survey'', ''Distribution center'', ''Dry gas or dry natural gas'', ''Hard spot'', ''In-line inspection (ILI)'', and ''In-line inspection tool or instrumented internal inspection device'' in alphabetical order;
■ b. Revise the definition for ''Transmission line''; and
■ c. Add the definition ''Wrinkle bend'' in alphabetical order.

The additions and revision read as follows:

§ 192.3 Definitions.

* * * * *

Close interval survey means a series of closely and properly spaced pipe-to-electrolyte potential measurements taken over the pipe to assess the adequacy of cathodic protection or to identify locations where a current may be leaving the pipeline that may cause corrosion and for the purpose of quantifying voltage (IR) drops other than those across the structure electrolyte boundary, such as when performed as a current interrupted, depolarized, or native survey.

* * * * *

Distribution center means the initial point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption, as opposed to customers who purchase it for resale, for example:

(1) At a metering location;

(2) A pressure reduction location; or

(3) Where there is a reduction in the volume of gas, such as a lateral off a transmission line.

* * * * *

Dry gas or dry natural gas means gas above its dew point and without condensed liquids.

* * * * *

Hard spot means an area on steel pipe material with a minimum dimension greater than two inches (50.8 mm) in any direction and hardness greater than or equal to Rockwell 35 HRC (Brinell 327 HB or Vickers 345 HV_{10}).

* * * * *

In-line inspection (ILI) means an inspection of a pipeline from the interior of the pipe using an inspection tool also called *intelligent* or *smart pigging.* This definition includes tethered and self-propelled inspection tools.

In-line inspection tool or *instrumented internal inspection device* means an instrumented device or vehicle that uses a non-destructive testing technique to inspect the pipeline from the inside in order to identify and characterize flaws to analyze pipeline integrity; also known as an *intelligent* or *smart pig.*

* * * * *

Transmission line means a pipeline or connected series of pipelines, other than a gathering line, that:

(1) Transports gas from a gathering pipeline or storage facility to a distribution center, storage facility, or large volume customer that is not downstream from a distribution center;

(2) Has an MAOP of 20 percent or more of SMYS;

(3) Transports gas within a storage field; or

(4) Is voluntarily designated by the operator as a transmission pipeline.

Note 1 to *transmission line.* A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas.

* * * * *

Wrinkle bend means a bend in the pipe that:

(1) Was formed in the field during construction such that the inside radius of the bend has one or more ripples with:

(i) An amplitude greater than or equal to 1.5 times the wall thickness of the pipe, measured from peak to valley of the ripple; or

(ii) With ripples less than 1.5 times the wall thickness of the pipe and with a wrinkle length (peak to peak) to wrinkle height (peak to valley) ratio under 12.

(2)(i) If the length of the wrinkle bend cannot be reliably determined, then wrinkle bend means a bend in the pipe where (h/D)*100 exceeds 2 when S is less than 37,000 psi (255 MPa), where (h/D)*100 exceeds for psi [for MPa] when S is greater than 37,000 psi (255 MPa) but less than 47,000 psi (324 MPa), and where (h/D)*100 exceeds 1 when S is 47,000 psi (324 MPa) or more.

(ii) Where:

(A) D = Outside diameter of the pipe, in. (mm);

(B) h = Crest-to-trough height of the ripple, in. (mm); and

(C) S = Maximum operating hoop stress, psi (S/145, MPa).

■ 3. In § 192.7:
■ a. Revise paragraphs (a) and (c)(6);
■ b. Redesignate paragraph (h)(1) as paragraph (h)(4) and paragraph (h)(2) as paragraph (h)(1);
■ c. Add new paragraph (h)(2) and paragraph (h)(3); and
■ d. Revise newly redesignated paragraph (h)(4).

The revisions and additions read as follows:

§ 192.7 What documents are incorporated by reference partly or wholly in this part?

(a) Certain material is incorporated by reference into this part with the approval of the Director of the Federal Register under 5 U.S.C. 552(a) and 1 CFR part 51. All approved material is available for inspection at the Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE, Washington, DC 20590, 202–366–4046, *https://www.phmsa.dot.gov/pipeline/regs,* and at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, email *fr.inspection@nara.gov,* or go to *www.archives.gov/federal-register/cfr/ibr-locations.html.* It is also available from the sources in the following paragraphs of this section.

* * * * *

(c) * * *

(6) ASME/ANSI B31.8S–2004, ''Supplement to B31.8 on Managing System Integrity of Gas Pipelines,'' approved January 14, 2005, (ASME/ANSI B31.8S), IBR approved for §§ 192.13(d); 192.714(c) and (d); 192.903 note to *potential impact radius;* 192.907 introductory text and (b); 192.911 introductory text, (i), and (k) through (m); 192.913(a) through (c); 192.917(a) through (e); 192.921(a); 192.923(b); 192.925(b); 192.927(b) and (c); 192.929(b); 192.933(c) and (d); 192.935(a) and (b); 192.937(c); 192.939(a); and 192.945(a).

* * * * *

(h) * * *

(2) NACE SP0204–2008, Standard Practice, ''Stress Corrosion Cracking (SCC) Direct Assessment Methodology,'' reaffirmed September 18, 2008, (NACE SP0204); IBR approved for §§ 192.923(b); 192.929(b) introductory text, (b)(1) through (3), (b)(5) introductory text, and (b)(5)(i).

(3) NACE SP0206–2006, Standard Practice, ''Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG–ICDA),'' approved December 1, 2006, (NACE SP0206), IBR approved for §§ 192.923(b); 192.927(b), (c) introductory text, and (c)(1) through (4).

(4) ANSI/NACE SP0502–2010, Standard Practice, ''Pipeline External Corrosion Direct Assessment Methodology,'' revised June 24, 2010, (NACE SP0502), IBR approved for §§ 192.319(f); 192.461(h); 192.923(b); 192.925(b); 192.931(d); 192.935(b); and 192.939(a).

* * * * *

■ 4. In § 192.9, paragraphs (b), (c), (d)(1) and (2), and (e)(1)(i) and (ii) are revised to read as follows:

§ 192.9 What requirements apply to gathering pipelines?

* * * * *

(b) *Offshore lines.* An operator of an offshore gathering line must comply with requirements of this part applicable to transmission lines, except the requirements in §§ 192.13(d), 192.150, 192.285(e), 192.319(d) through (g), 192.461(f) through (i), 192.465(d) and (f), 192.473(c), 192.478, 192.485(c), 192.493, 192.506, 192.607, 192.613(c), 192.619(e), 192.624, 192.710, 192.712, and 192.714 and in subpart O of this part.

(c) *Type A lines.* An operator of a Type A regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines, except the requirements in §§ 192.13(d), 192.150, 192.285(e), 192.319(d) through (g), 192.461(f) through (i), 192.465(d) and (f), 192.473(c), 192.478, 192.485(c) 192.493, 192.506, 192.607, 192.613(c), 192.619(e), 192.624, 192.710, 192.712, and 192.714 and in subpart O of this part. However, an operator of a Type A regulated onshore gathering line in a Class 2 location may demonstrate compliance with subpart N of this part by describing the processes it uses to determine the qualification of persons performing operations and maintenance tasks.

(d) * * *

(1) If a line is new, replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of this part applicable to transmission lines. Compliance with §§ 192.67, 192.127, 192.179(e) and (f), 192.205, 192.227(c), 192.285(e), 192.319(d) through (g), 192.506, 192.634, and 192.636 is not required;

(2) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines, except the requirements in §§ 192.461(f) through (i), 192.465(d) and (f), 192.473(c), 192.478, 192.485(c), and 192.493;

* * * * *

(e) * * *

(1) * * *

(i) Except as provided in paragraph (h) of this section for pipe and components made with composite materials, the design, installation, construction, initial inspection, and initial testing of a new, replaced, relocated, or otherwise changed Type C gathering line, must be done in accordance with the requirements in subparts B through G and J of this part applicable to transmission lines. Compliance with §§ 192.67, 192.127, 192.179(e) and (f), 192.205, 192.227(c), 192.285(e), 192.319(d) through (g), 192.506, 192.634, and 192.636 is not required;

(ii) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines, except the requirements in §§ 192.461(f) through (i), 192.465(d) and (f), 192.473(c), 192.478, 192.485(c), and 192.493;

* * * * *

■ 5. In § 192.13, paragraph (d) is added to read as follows:

§ 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. 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 (incorporated by reference, *see* § 192.7), 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: reason for change, authority for approving changes, analysis of implications, acquisition of required work permits, documentation, communication of change to affected parties, time limitations, and qualification of staff. For pipeline segments other than those covered in subpart O of this part, this management of change process must be implemented by February 26, 2024. The requirements of this paragraph (d) do not apply to gas gathering pipelines. Operators may request an extension of up to 1 year by submitting a notification to PHMSA at least 90 days before February 26, 2024, in accordance with § 192.18. The notification must include a reasonable and technically justified basis, an up-to-date plan for completing all actions required by this section, the reason for the requested extension, current safety or mitigation status of the pipeline segment, the proposed completion date, and any needed temporary safety measures to mitigate the impact on safety.

■ 6. In § 192.18, paragraph (c) is revised to read as follows:

§ 192.18 How to notify PHMSA.

* * * * *

(c) Unless otherwise specified, if an operator submits, pursuant to § 192.8, § 192.9, § 192.13, § 192.179, § 192.319, § 192.461, § 192.506, § 192.607, § 192.619, § 192.624, § 192.632, § 192.634, § 192.636, § 192.710, § 192.712, § 192.714, § 192.745, § 192.917, § 192.921, § 192.927, § 192.933, or § 192.937, a notification for use of a different integrity assessment method, analytical method, compliance period, sampling approach, pipeline material, or technique (*e.g.,* ''other technology'' or ''alternative equivalent technology'') than otherwise prescribed in those sections, that notification must be submitted to PHMSA for review at least 90 days in advance of using the other method, approach, compliance timeline, or technique. An operator may proceed to use the other method, approach, compliance timeline, or technique 91 days after submitting the notification unless it receives a letter from the Associate Administrator for Pipeline Safety informing the operator that PHMSA objects to the proposal or that PHMSA requires additional time and/or more information to conduct its review.

■ 7. In § 192.319, paragraphs (d) through (g) are added to read as follows:

§ 192.319 Installation of pipe in a ditch.

* * * * *

(d) Promptly after a ditch for an onshore steel transmission line is backfilled (if the construction project involves 1,000 feet or more of continuous backfill length along the pipeline), but not later than 6 months after placing the pipeline in service, the operator must perform an assessment to assess any coating damage and ensure integrity of the coating using direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or other technology that provides comparable information about the integrity of the coating. Coating surveys must be conducted, except in locations where effective coating surveys are precluded by geographical, technical, or safety reasons.

(e) An operator must notify PHMSA in accordance with § 192.18 at least 90 days in advance of using other technology to assess integrity of the coating under paragraph (d) of this section.

(f) An operator must repair any coating damage classified as severe (voltage drop greater than 60 percent for DCVG or 70 dBμV for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, *see* § 192.7) within 6 months after the pipeline is placed in service, or as soon as practicable after obtaining necessary permits, not to exceed 6 months after the receipt of permits.

(g) An operator of an onshore steel transmission pipeline must make and retain for the life of the pipeline records documenting the coating assessment findings and remedial actions performed under paragraphs (d) through (f) of this section.

■ 8. In § 192.461, paragraph (a)(4) is revised and paragraphs (f) through (i) are added to read as follows:

§ 192.461 External corrosion control: Protective coating.

(a) * * *

(4) Have sufficient strength to resist damage due to handling (including, but not limited to, transportation, installation, boring, and backfilling) and soil stress; and

* * * * *

(f) Promptly after the backfill of an onshore steel 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), but no later than 6 months after the backfill, the operator must perform an assessment to assess any coating damage and ensure integrity of the coating using direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or other technology that provides comparable information about the integrity of the coating. Coating surveys must be conducted, except in locations where effective coating surveys are precluded by geographical, technical, or safety reasons.

(g) An operator must notify PHMSA in accordance with § 192.18 at least 90 days in advance of using other technology to assess integrity of the coating under paragraph (f) of this section.

(h) An operator of an onshore steel transmission pipeline must develop a remedial action plan and apply for any necessary permits within 6 months of completing the assessment that identified the deficiency. The operator must repair any coating damage classified as severe (voltage drop greater than 60 percent for DCVG or 70 dBμV for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, *see* § 192.7) within 6 months of the assessment, or as soon as practicable after obtaining necessary permits, not to exceed 6 months after the receipt of permits.

(i) An operator of an onshore steel transmission pipeline must make and retain for the life of the pipeline records documenting the coating assessment findings and remedial actions performed under paragraphs (f) through (h) of this section.

■ 9. In § 192.465, the section heading and paragraph (d) are revised and paragraph (f) is added to read as follows:

§ 192.465 External corrosion control: Monitoring and remediation.

* * * * *

(d) Each operator must promptly correct any deficiencies indicated by the inspection and testing required by paragraphs (a) through (c) of this section. For onshore gas transmission pipelines, each operator must develop a remedial action plan and apply for any necessary permits within 6 months of completing the inspection or testing that identified the deficiency. Remedial action must be completed promptly, but no later than the earliest of the following: prior to the next inspection or test interval required by this section; within 1 year, not to exceed 15 months, of the inspection or test that identified the deficiency; or as soon as practicable, not to exceed 6 months, after obtaining any necessary permits.

* * * * *

(f) An operator must determine the extent of the area with inadequate cathodic protection for onshore gas transmission pipelines where any annual test station reading (pipe-to-soil potential measurement) indicates cathodic protection levels below the required levels in appendix D to this part.

(1) Gas transmission pipeline operators must investigate and mitigate any non-systemic or location-specific causes.

(2) To address systemic causes, an operator must conduct close interval surveys in both directions from the test station with a low cathodic protection reading at a maximum interval of approximately 5 feet or less. An operator must conduct close interval surveys unless it is impractical based upon geographical, technical, or safety reasons. An operator must complete close interval surveys required by this section with the protective current interrupted unless it is impractical to do so for technical or safety reasons. An operator must remediate areas with insufficient cathodic protection levels, or areas where protective current is found to be leaving the pipeline, in accordance with paragraph (d) of this section. An operator must confirm the restoration of adequate cathodic protection following the implementation of remedial actions undertaken to mitigate systemic causes of external corrosion.

■ 10. In § 192.473, paragraph (c) is added to read as follows:

§ 192.473 External corrosion control: Interference currents.

* * * * *

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

(1) Interference surveys for a pipeline system to detect the presence and level of any electrical stray current. Interference surveys must be conducted when potential monitoring indicates a significant increase in stray current, or when new potential stray current sources are introduced, such as through 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, or 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 cause significant corrosion, impede safe operation, or adversely affect the environment or public;

(3) Development of a remedial action plan to correct any instances where interference current is greater than or equal to 100 amps per meter squared or if it impedes the safe operation of a pipeline, or if it may cause a condition that would adversely impact the environment or the public; and

(4) Application for any necessary permits within 6 months of completing the interference survey that identified

the deficiency. An operator must complete remedial actions promptly, but no later than the earliest of the following: within 15 months after completing the interference survey that identified the deficiency; or as soon as practicable, but not to exceed 6 months, after obtaining any necessary permits.

■ 11. Section 192.478 is added to read as follows:

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

(a) Each operator of an onshore gas transmission pipeline with corrosive constituents in the gas being transported must develop and implement a monitoring and mitigation program to mitigate the corrosive effects, as necessary. Potentially corrosive constituents include, but are not limited to: carbon dioxide, hydrogen sulfide, sulfur, microbes, and liquid water, either by itself or in combination. An 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 and implement mitigation measures as necessary.

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

(1) The use of gas-quality monitoring methods at points where gas with potentially corrosive contaminants enters the pipeline to determine the gas stream constituents.

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

(3) An evaluation at least once each calendar year, at intervals not to exceed 15 months, to ensure that potentially corrosive gas stream constituents are effectively monitored and mitigated.

(c) An operator must review its monitoring and mitigation program at least once each calendar year, at intervals not to exceed 15 months, and based on the results of its monitoring and mitigation program, implement adjustments, as necessary.

■ 12. In § 192.485, paragraph (c) is revised to read as follows:

§ 192.485 Remedial measures: Transmission lines.

* * * * *

(c) *Calculating remaining strength.* Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness must be determined and documented in accordance with § 192.712.

■ 13. In § 192.613, paragraph (c) is added to read as follows:

§ 192.613 Continuing surveillance.

* * * * *

(c) Following an extreme weather event or natural disaster that has the likelihood of damage to pipeline facilities by the scouring or movement of the soil surrounding the pipeline or movement of the pipeline, such as a named tropical storm or hurricane; a flood that exceeds the river, shoreline, or creek high-water banks in the area of the pipeline; a landslide in the area of the pipeline; or an earthquake in the area of the pipeline, an operator must inspect all potentially affected onshore transmission pipeline facilities to detect conditions that could adversely affect the safe operation of that pipeline.

(1) An operator must assess 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 the extent of any damage and the need for the additional assessments required under this paragraph (c)(1).

(2) An operator must commence the inspection required by paragraph (c) of this section within 72 hours after the point in time when the operator reasonably determines that the affected area can be safely accessed by personnel and equipment, and the personnel and equipment required to perform the inspection as determined by paragraph (c)(1) of this section are available. If an operator is unable to commence the inspection due to the unavailability of personnel or equipment, the operator must notify the appropriate PHMSA Region Director as soon as practicable.

(3) An operator must take prompt and appropriate remedial action to ensure the safe operation of a pipeline based on the information obtained as a result of performing the inspection required by paragraph (c) of 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.

■ 14. In § 192.710, paragraph (f) is revised as follows:

§ 192.710 Transmission lines: Assessments outside of high consequence areas.

* * * * *

(f) *Remediation.* An operator must comply with the requirements in §§ 192.485, 192.711, 192.712, 192.713, and 192.714, where applicable, if a condition that could adversely affect the safe operation of a pipeline is discovered.

* * * * *

■ 15. In § 192.711, paragraph (b)(1) is revised to read as follows:

§ 192.711 Transmission lines: General requirements for repair procedures.

* * * * *

(b) * * *

(1)(i) Non-integrity management repairs for gathering lines and offshore transmission lines: For gathering lines subject to this section in accordance with § 192.9 and for offshore transmission lines, an operator must make permanent repairs as soon as feasible.

(ii) Non-integrity management repairs for onshore transmission lines: Except for gathering lines exempted from this section in accordance with § 192.9 and offshore transmission lines, after May 24, 2023, whenever an operator discovers any condition that could adversely affect the safe operation of a pipeline segment not covered by an integrity management program under subpart O of this part, it must correct the condition as prescribed in § 192.714.

* * * * *

■ 16. In § 192.712, the section heading and paragraph (b) are revised and paragraphs (c) and (h) are added to read as follows:

§ 192.712 Analysis of predicted failure pressure and critical strain level.

* * * * *

(b) *Corrosion metal loss.* When analyzing corrosion metal loss under this section, an operator must use a suitable remaining strength calculation method including, ASME/ANSI B31G (incorporated by reference, *see* § 192.7); R–STRENG (incorporated by reference, *see* § 192.7); or an alternative equivalent method of remaining strength calculation that will provide an equally conservative result.

(1) If an operator would choose to use a remaining strength calculation method that could provide a less conservative result than the methods listed in

paragraph (b) introductory text, the operator must notify PHMSA in advance in accordance with § 192.18(c).

(2) The notification provided for by paragraph (b)(1) of this section must include a comparison of its predicted failure pressures to R–STRENG or ASME/ANSI B31G, all burst pressure tests used, and any other technical reviews used to qualify the calculation method(s) for varying corrosion profiles.

(c) *Dents and other mechanical damage.* To evaluate dents and other mechanical damage that could result in a stress riser or other integrity impact, an operator must develop a procedure and perform an engineering critical assessment as follows:

(1) Identify and evaluate potential threats to the pipe segment in the vicinity of the anomaly or defect, including ground movement, external loading, fatigue, cracking, and corrosion.

(2) Review high-resolution magnetic flux leakage (HR–MFL) high-resolution deformation, inertial mapping, and crack detection inline inspection data for damage in the dent area and any associated weld region, including available data from previous inline inspections.

(3) Perform pipeline curvature-based strain analysis using recent HR-Deformation inspection data.

(4) Compare the dent profile between the most recent and previous in-line inspections to identify significant changes in dent depth and shape.

(5) Identify and quantify all previous and present significant loads acting on the dent.

(6) Evaluate the strain level associated with the anomaly or defect and any nearby welds using Finite Element Analysis, or other technology in accordance with this section. Using Finite Element Analysis to quantify the dent strain, and then estimating and evaluating the damage using the Strain Limit Damage (SLD) and Ductile Failure Damage Indicator (DFDI) at the dent, are appropriate evaluation methods.

(7) The analyses performed in accordance with this section must account for material property uncertainties, model inaccuracies, and inline inspection tool sizing tolerances.

(8) Dents with a depth greater than 10 percent of the pipe outside diameter or with geometric strain levels that exceed the lessor of 10 percent or exceed the critical strain for the pipe material properties must be remediated in accordance with § 192.713, § 192.714, or § 192.933, as applicable.

(9) Using operational pressure data, a valid fatigue life prediction model that is appropriate for the pipeline segment, and assuming a reassessment safety factor of 5 or greater for the assessment interval, estimate the fatigue life of the dent by Finite Element Analysis or other analytical technique that is technically appropriate for dent assessment and reassessment intervals in accordance with this section. Multiple dent or other fatigue models must be used for the evaluation as a part of the engineering critical assessment.

(10) If the dent or mechanical damage is suspected to have cracks, then a crack growth rate assessment is required to ensure adequate life for the dent with crack(s) until remediation or the dent with crack(s) must be evaluated and remediated in accordance with the criteria and timing requirements in § 192.713, § 192.714, or § 192.933, as applicable.

(11) An operator using an engineering critical assessment procedure, other technologies, or techniques to comply with paragraph (c) of this section must submit advance notification to PHMSA, with the relevant procedures, in accordance with § 192.18.

* * * * *

(h) *Reassessments.* If an operator uses an engineering critical assessment method in accordance with paragraphs (c) and (d) of this section to determine the maximum reevaluation intervals, the operator must reassess the anomalies as follows:

(1) If the anomaly is in an HCA, the operator must reassess the anomaly within a maximum of 7 years in accordance with § 192.939(a), unless the safety factor is expected to go below what is specified in paragraph (c) or (d) of this section.

(2) If the anomaly is outside of an HCA, the operator must perform a reassessment of the anomaly within a maximum of 10 years in accordance with § 192.710(b), unless the anomaly safety factor is expected to go below what is specified in paragraph (c) or (d) of this section.

■ 17. Section 192.714 is added to read as follows:

§ 192.714 Transmission lines: Repair criteria for onshore transmission pipelines.

(a) *Applicability.* This section applies to onshore transmission pipelines not subject to the repair criteria in subpart O of this part, and which do not operate under an alternative MAOP in accordance with §§ 192.112, 192.328, and 192.620. Pipeline segments that are located in high consequence areas, as defined in § 192.903, must comply with the applicable actions specified by the integrity management requirements in subpart O. Pipeline segments operating under an alternative MAOP in accordance with §§ 192.112, 192.328, and 192.620 must comply with § 192.620(d)(11).

(b) *General.* Each operator must, in repairing its pipeline systems, ensure that the repairs are made in a safe manner and are made to prevent damage to persons, property, and the environment. A pipeline segment's operating pressure must be less than the predicted failure pressure determined in accordance with § 192.712 during repair operations. Repairs performed in accordance with this section must use pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis, including predicted failure pressure for determining MAOP, is not available, an operator must obtain the undocumented data through § 192.607.

(c) *Schedule for evaluation and remediation.* An operator must remediate conditions according to a schedule that prioritizes the conditions for evaluation and remediation. Unless paragraph (d) of this section provides a special requirement for remediating certain conditions, an operator must calculate the predicted failure pressure of anomalies or defects and follow the schedule in ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must document the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety. Each condition that meets any of the repair criteria in paragraph (d) of this section in an onshore steel transmission pipeline must be—

(1) Removed by cutting out and replacing a cylindrical piece of pipe that will permanently restore the pipeline's MAOP based on the use of § 192.105 and the design factors for the class location in which it is located; or

(2) Repaired by a method, shown by technically proven engineering tests and analyses, that will permanently restore the pipeline's MAOP based upon the determined predicted failure pressure times the design factor for the class location in which it is located.

(d) *Remediation of certain conditions.* For onshore transmission pipelines not located in high consequence areas, an operator must remediate a listed condition according to the following criteria:

(1) *Immediate repair conditions.* An operator must repair the following conditions immediately upon discovery:

(i) Metal loss anomalies where a calculation of the remaining strength of the pipe at the location of the anomaly shows a predicted failure pressure, determined in accordance with § 192.712(b), of less than or equal to 1.1 times the MAOP.

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.

(iii) Metal loss greater than 80 percent of nominal wall regardless of dimensions.

(iv) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or has a longitudinal joint factor less than 1.0, and the predicted failure pressure determined in accordance with § 192.712(d) is less than 1.25 times the MAOP.

(v) A crack or crack-like anomaly meeting any of the following criteria:

(A) Crack depth plus any metal loss is greater than 50 percent of pipe wall thickness;

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

(C) The crack or crack-like anomaly has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.25 times the MAOP.

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

(2) *Two-year conditions.* An operator must repair the following conditions within 2 years of discovery:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.

(ii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal or helical (spiral) seam weld, unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.

(iii) A dent located between the 4 o'clock and 8 o'clock positions (lower ⅓ of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.

(iv) For metal loss anomalies, a calculation of the remaining strength of the pipe shows a predicted failure pressure, determined in accordance with § 192.712(b) at the location of the anomaly, of less than 1.39 times the MAOP for Class 2 locations, or less than 1.50 times the MAOP for Class 3 and 4 locations. For metal loss anomalies in Class 1 locations with a predicted failure pressure greater than 1.1 times MAOP, an operator must follow the remediation schedule specified in ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 7, Figure 4, as specified in paragraph (c) of this section.

(v) Metal loss that is located at a crossing of another pipeline, is in an area with widespread circumferential corrosion, or could affect a girth weld, and that has a predicted failure pressure, determined in accordance with § 192.712(b), less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vi) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or that has a longitudinal joint factor less than 1.0, and where the predicted failure pressure determined in accordance with § 192.712(d) is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vii) A crack or crack-like anomaly that has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(3) *Monitored conditions.* An operator must record and monitor the following conditions during subsequent risk assessments and integrity assessments for any change that may require remediation.

(i) A dent that is located between the 4 o'clock and 8 o'clock positions (bottom ⅓ of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12).

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), and where an engineering analysis performed in accordance with § 192.712(c) determines that critical strain levels are not exceeded.

(iii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or longitudinal or helical (spiral) seam weld, and where an engineering analysis of the dent and girth or seam weld, performed in accordance with § 192.712(c), demonstrates critical strain levels are not exceeded. These analyses must consider weld mechanical properties.

(iv) A dent that has metal loss, cracking, or a stress riser, and where an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.

(v) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or that has a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with § 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or is greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vi) A crack or crack-like anomaly for which the predicted failure pressure, determined in accordance with § 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or is greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(e) *Temporary pressure reduction.* (1) Immediately upon discovery and until an operator remediates the condition specified in paragraph (d)(1) of this section, or upon a determination by an operator that it is unable to respond within the time limits for the conditions specified in paragraph (d)(2) of this section, the operator must reduce the operating pressure of the affected pipeline to any one of the following based on safety considerations for the public and operating personnel:

(i) A level not exceeding 80 percent of the operating pressure at the time the condition was discovered;

(ii) A level not exceeding the predicted failure pressure times the design factor for the class location in which the affected pipeline is located; or

(iii) A level not exceeding the predicted failure pressure divided by 1.1.

(2) An operator must notify PHMSA in accordance with § 192.18 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) or (d) of this section and cannot provide safety through a temporary reduction in operating pressure or other action. Notification to PHMSA does not alleviate an operator from the evaluation, remediation, or pressure reduction requirements in this section.

(3) When a pressure reduction, in accordance with paragraph (e) of this section, exceeds 365 days, an operator must notify PHMSA in accordance with § 192.18 and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline.

(4) An operator must document and keep records of the calculations and decisions used to determine the reduced operating pressure and the implementation of the actual reduced operating pressure for a period of 5 years after the pipeline has been repaired.

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

(g) *In situ direct examination of crack defects.* Whenever an operator finds conditions that require the pipeline to be repaired, in accordance with this section, an operator must perform a direct examination of known locations of cracks or crack-like defects using technology that has been validated to detect tight cracks (equal to or less than 0.008 inches crack opening), such as inverse wave field extrapolation (IWEX), phased array ultrasonic testing (PAUT), ultrasonic testing (UT), or equivalent technology. ''In situ'' examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards, including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection for accuracy of the type of defects and pipe material being evaluated. The procedures must account for inaccuracies in evaluations and fracture mechanics models for failure pressure determinations.

(h) *Determining predicted failure pressures and critical strain levels.* An operator must perform all determinations of predicted failure pressures and critical strain levels required by this section in accordance with § 192.712.

■ 18. In § 192.911, paragraph (k) is revised to read as follows:

§ 192.911 What are the elements of an integrity management program?

* * * * *

(k) A management of change process as required by § 192.13(d).

* * * * *

■ 19. In § 192.917, paragraphs (a) through (d) are revised to read as follows:

§ 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 threat categories:

(1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;

(2) Stable threats, such as manufacturing, welding, fabrication, or construction defects;

(3) Time independent threats, such as third party damage, mechanical damage, incorrect operational procedure, weather related and outside force damage, to include consideration of seismicity, geology, and soil stability of the area; and

(4) Human error, such as operational or maintenance mishaps, or 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 and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4.

Operators must begin to integrate all pertinent data elements specified in this section starting on May 24, 2023, with all available attributes integrated by February 26, 2024. An operator may request an extension of up to 1 year by submitting a notification to PHMSA at least 90 days before February 26, 2024, in accordance with § 192.18. The notification must include a reasonable and technically justified basis, an up-to-date plan for completing all actions required by this paragraph (b), the reason for the requested extension, current safety or mitigation status of the pipeline segment, the proposed completion date, and any needed temporary safety measures to mitigate the impact on safety. An operator must gather and evaluate the set of data listed in paragraph (b)(1) of this section. The evaluation must analyze both the covered segment and similar non-covered segments, and it must:

(1) Integrate pertinent information about pipeline attributes to ensure safe operation and pipeline integrity, including information derived from operations and maintenance activities required under this part, and other relevant information, including, but not limited to:

(i) Pipe diameter, wall thickness, seam type, and joint factor;

(ii) Manufacturer and manufacturing date, including manufacturing data and records;

(iii) Material properties including, but not limited to, grade, specified minimum yield strength (SMYS), and ultimate tensile strength;

(iv) Equipment properties;

(v) Year of installation;

(vi) Bending method;

(vii) Joining method, including process and inspection results;

(viii) Depth of cover;

(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 the 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) Post backfill coating surveys; and

(B) Coating inspection (''jeeping'' or ''holiday inspection'') reports;

(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) Cathodic protection (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 assessments, guided wave ultrasonic testing, or other methods;

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

(C) CP rectifier readings;

(D) CP test point survey readings and locations;

(E) Alternating current, direct current, 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 excavations and findings;

(I) Selective seam weld corrosion excavations and findings;

(J) Any indication of seam cracking; and

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

(xxv) External and internal corrosion monitoring;

(xxvi) Operating pressure history and pressure fluctuations, including an 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;

(xxix) Repairs;

(xxx) Vandalism;

(xxxi) External forces;

(xxxii) Audits and reviews;

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

(xxxiv) Aerial photography; and

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

(2) Use validated information and data as inputs, to the maximum extent practicable. If input is obtained from subject matter experts (SME), an operator must employ adequate control measures to ensure consistency and accuracy of information. Control measures may include training of SMEs or the use of outside technical experts (independent expert reviews) to assess the quality of processes and the judgment of SMEs. An operator must document the names and qualifications of the individuals who approve SME inputs used in the current risk assessment.

(3) Identify and analyze spatial relationships among anomalous information (*e.g.,* corrosion coincident with foreign line crossings or evidence of pipeline damage where overhead imaging shows evidence of encroachment).

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

(c) *Risk assessment.* An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, section 5, and that analyzes the identified threats and potential consequences of an incident for each covered segment. An operator must ensure the validity of the methods used to conduct the risk assessment considering the incident, leak, and failure history of the pipeline segments and other historical information. Such a 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 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 for each covered segment in accordance with § 192.935 and periodically evaluate the integrity of each covered pipeline segment in accordance with § 192.937. Beginning February 26, 2024, the risk assessment must:

(1) Analyze how a potential failure could affect high consequence areas;

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

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

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

(5) In conjunction with § 192.917(b), an operator may request an extension of up to 1 year for the requirements of this paragraph by submitting a notification to PHMSA at least 90 days before February 26, 2024, in accordance with § 192.18. The notification must include a reasonable and technically justified basis, an up-to-date plan for completing all actions required by this paragraph (c)(5), the reason for the requested extension, current safety or mitigation status of the pipeline segment, the proposed completion date, and any needed temporary safety measures to mitigate the impact on safety.

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

* * * * *

■ 20. In § 192.923, paragraphs (b)(2) and (3) are revised to read as follows:

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

* * * * *

(b) * * *

(2) Section 192.927 and NACE SP0206 (incorporated by reference, *see* § 192.7), if addressing internal corrosion (IC).

(3) Section 192.929 and NACE SP0204 (incorporated by reference, *see* § 192.7), if addressing stress corrosion cracking (SCC).

* * * * *

■ 21. In § 192.927, paragraphs (b) and (c) are revised to read as follows:

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

* * * * *

(b) *General requirements.* An operator using direct assessment as an assessment method to address internal corrosion in a covered pipeline segment must follow the requirements in this section and in NACE SP0206 (incorporated by reference, *see* § 192.7). The Dry Gas Internal Corrosion Direct Assessment (DG–ICDA) process described in this section applies only for a segment of pipe transporting normally dry natural gas (*see* § 192.3) and not for a segment with electrolytes normally present in the gas stream. If an operator uses ICDA to assess a covered segment operating with electrolytes present in the gas stream, the operator must develop a plan that demonstrates how it will conduct ICDA in the segment to address internal corrosion effectively and must notify PHMSA in accordance with § 192.18. In the event of a conflict between this section and NACE SP0206, the requirements in this section control.

(c) *The ICDA plan.* An operator must develop and follow an ICDA plan that meets NACE SP0206 (incorporated by reference, *see* § 192.7) and that implements all four steps of the DG–ICDA process, including pre-assessment, indirect inspection, detailed examination at excavation locations, and post-assessment evaluation and monitoring. The plan must identify the locations of all ICDA regions within covered segments in the transmission system. An ICDA region is a continuous length of pipe (including weld joints), uninterrupted by any significant change in water or flow characteristics, that includes similar physical characteristics or operating history. An ICDA region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur until a new input introduces the possibility of water entering the pipeline. In cases where a single covered segment is partially located in two or more ICDA regions, the four-step ICDA process must be completed for each ICDA region in which the covered segment is partially located to complete the assessment of the covered segment.

(1) *Preassessment.* An operator must comply with NACE SP0206 (incorporated by reference, *see* § 192.7) in conducting the preassessment step of the ICDA process.

(2) *Indirect inspection.* An operator must comply with NACE SP0206 (incorporated by reference, *see* § 192.7), and the following additional requirements, in conducting the Indirect Inspection step of the ICDA process. An operator must explicitly document the results of its feasibility assessment as required by NACE SP0206, section 3.3 (incorporated by reference, *see* § 192.7); if any condition that precludes the successful application of ICDA applies, then ICDA may not be used, and another assessment method must be selected. When performing the indirect inspection, the operator must use actual pipeline-specific data, exclusively. The use of assumed pipeline or operational data is prohibited. When calculating the critical inclination angle of liquid holdup and the inclination profile of the pipeline, the operator must consider the accuracy, reliability, and uncertainty of the data used to make those calculations, including, but not limited to, gas flow velocity (including during upset conditions), pipeline elevation profile survey data (including specific profile at features with inclinations such as road crossings, river crossings, drains, valves, drips, etc.), topographical data, and depth of cover. An operator must select locations for direct examination and establish the extent of pipe exposure needed (*i.e.,* the size of the bell hole), to account for these uncertainties and their cumulative effect on the precise location of predicted liquid dropout.

(3) *Detailed examination.* An operator must comply with NACE SP0206 (incorporated by reference, *see* § 192.7) in conducting the detailed examination step of the ICDA process. When an operator first uses ICDA for a covered segment, an operator must identify a minimum of two locations for excavation within each covered segment associated with the ICDA region and must perform a detailed examination for internal corrosion at each location using ultrasonic thickness measurements, radiography, or other generally accepted measurement techniques that can examine for internal corrosion or other threats that are being assessed. One location must be the low point (*e.g.,* sag, drip, valve, manifold, dead-leg) within the covered segment nearest to the beginning of the ICDA region. The second location must be further downstream, within the covered segment, near the end of the ICDA region. Whenever corrosion is found during ICDA at any location, the operator must:

(i) Evaluate the severity of the defect (remaining strength) and remediate the defect in accordance with § 192.933 if the condition is in a covered segment, or in accordance with §§ 192.485 and 192.714 if the condition is not in a covered segment;

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

(iii) Expand the detailed examination program to evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator's pipeline system with similar characteristics to the ICDA region in which the corrosion was found and remediate identified instances of internal corrosion in accordance with either § 192.933 or §§ 192.485 and 192.714, as appropriate.

(4) *Post-assessment evaluation and monitoring.* An operator must comply with NACE SP0206 (incorporated by reference, *see* § 192.7) in performing the post assessment step of the ICDA process. In addition to NACE SP0206, the evaluation and monitoring process must also include—

(i) An evaluation of the effectiveness of ICDA as an assessment method for addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals than those specified in § 192.939. An operator must carry out this evaluation within 1 year of conducting an ICDA;

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

(iii) Continuous monitoring of each ICDA region that contains a covered segment where internal corrosion has been identified by using techniques such as coupons or ultrasonic (UT) sensors or electronic probes, and by periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products. An operator must base the frequency of the monitoring and liquid analysis on results from all integrity assessments that have been conducted in accordance with the requirements of this subpart and risk factors specific to the ICDA region.

At a minimum, the monitoring frequency must be two times each calendar year, but at intervals not exceeding 7½ months. If an operator finds any evidence of corrosion products in the ICDA region, the operator must take prompt action in accordance with one of the two following required actions, and remediate the conditions the operator finds in accordance with § 192.933 or §§ 192.485 and 192.714, as applicable.

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

(B) Assess the covered segment using another integrity assessment method allowed by this subpart.

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

(i) Criteria an operator will apply in making key decisions (including, but not limited to, ICDA feasibility, definition of ICDA regions and sub-regions, and conditions requiring excavation) in implementing each stage of the ICDA process; and

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

■ 22. Section 192.929 is revised to read as follows:

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

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

(b) *General requirements.* An operator using direct assessment as an integrity assessment method for addressing SCC in a covered pipeline segment must develop and follow an SCCDA plan that meets NACE SP0204 (incorporated by reference, *see* § 192.7) and that implements all four steps of the SCCDA process, including pre-assessment, indirect inspection, detailed examination at excavation locations, and post-assessment evaluation and monitoring. As specified in NACE SP0204, SCCDA is complementary with other inspection methods for SCC, such as in-line inspection or hydrostatic testing with a spike test, and it is not necessarily an alternative or replacement for these methods in all instances. Additionally, the plan must provide for—

(1) *Data gathering and integration.* An operator's plan must provide for a systematic process to collect and evaluate data for all covered pipeline segments to identify whether the conditions for SCC are present and to prioritize the covered pipeline segments for assessment in accordance with NACE SP0204, sections 3 and 4, and Table 1 (incorporated by reference, *see* § 192.7). This process must also include gathering and evaluating data related to SCC at all sites an operator excavates while conducting its pipeline operations (both within and outside covered segments) where the criteria in NACE SP0204 (incorporated by reference, *see* § 192.7) indicate the potential for SCC. This data gathering process must be conducted in accordance with NACE SP0204, section 5.3 (incorporated by reference, *see* § 192.7), and must include, at a minimum, all data listed in NACE SP0204, Table 2 (incorporated by reference, *see* § 192.7). Further, the following factors must be analyzed as part of this evaluation:

(i) The effects of a carbonate-bicarbonate environment, including the implications of any factors that promote the production of a carbonate-bicarbonate environment, such as soil temperature, moisture, the presence or generation of carbon dioxide, or cathodic protection (CP);

(ii) The effects of cyclic loading conditions on the susceptibility and propagation of SCC in both high-pH and near-neutral-pH environments;

(iii) The effects of variations in applied CP, such as overprotection, CP loss for extended periods, and high negative potentials;

(iv) The effects of coatings that shield CP when disbonded from the pipe; and

(v) Other factors that affect the mechanistic properties associated with SCC, including, but not limited to, historical and present-day operating pressures, high tensile residual stresses, flowing product temperatures, and the presence of sulfides.

(2) *Indirect inspection.* In addition to NACE SP0204, the plan's procedures for indirect inspection must include provisions for conducting at least two above ground surveys using the complementary measurement tools most appropriate for the pipeline segment based on an evaluation of integrated data.

(3) *Direct examination.* In addition to NACE SP0204, the plan's procedures for direct examination must provide for an operator conducting a minimum of three direct examinations for SCC within the covered pipeline segment spaced at the locations determined to be the most likely for SCC to occur.

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

(i) Removing the pipe with SCC; remediating the pipe with a Type B sleeve; performing hydrostatic testing in accordance with paragraph (b)(4)(ii) of this section; or by grinding out the SCC defect and repairing the pipe. If an operator uses grinding for repair, the operator must also perform the following as a part of the repair procedure: nondestructive testing for any remaining cracks or other defects; a measurement of the remaining wall thickness; and a determination of the remaining strength of the pipe at the repair location that is performed in accordance with § 192.712 and that meets the design requirements of §§ 192.111 and 192.112, as applicable. The pipe and material properties an operator uses in remaining strength calculations must be documented in traceable, verifiable, and complete records. If such records are not available, an operator must base the pipe and material properties used in the remaining strength calculations on properties determined and documented in accordance with § 192.607, if applicable.

(ii) Performing a spike pressure test in accordance with § 192.506 based upon the class location of the pipeline segment. The MAOP must be no greater than the test pressure specified in

§ 192.506(a) divided by: 1.39 for Class 1 locations and Class 2 locations that contain Class 1 pipe that has been uprated in accordance with § 192.611; and 1.50 for all other Class 2 locations and all Class 3 and Class 4 locations. An operator must repair any test failures due to SCC by replacing the pipe segment and re-testing the segment until the pipe passes the test without failures (such as pipe seam or gasket leaks, or a pipe rupture). At a minimum, an operator must repair pipe segments that pass the pressure test but have SCC present by grinding the segment in accordance with paragraph (b)(4)(i) of this section.

(5) *Post assessment.* An operator's procedures for post-assessment, in addition to the procedures listed in NACE SP0204, sections 6.3, ''periodic reassessment,'' and 6.4, ''effectiveness of SCCDA,'' must include the development of a reassessment plan based on the susceptibility of the operator's pipe to SCC as well as the mechanistic behavior of identified cracking. An operator's reassessment intervals must comply with § 192.939. The plan must include the following factors, in addition to any factors the operator determines appropriate:

(i) The evaluation of discovered crack clusters during the direct examination step in accordance with NACE SP0204, sections 5.3.5.7, 5.4, and 5.5 (incorporated by reference, *see* § 192.7);

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

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

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

(v) Cyclic loading conditions;

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

(vii) The effects of interacting crack clusters;

(viii) The presence of sulfides; and

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

■ 23. In § 192.933, paragraphs (a) introductory text, (a)(1), (b), and (d) are revised and paragraph (e) is added read as follows:

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

(a) *General requirements.* An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment. Repairs performed in accordance with this section must use pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis is not available, an operator must obtain the undocumented data through § 192.607.

(1) *Temporary pressure reduction.* (i) If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must reduce the operating pressure to one of the following:

(A) A level not exceeding 80 percent of the operating pressure at the time the condition was discovered;

(B) A level not exceeding the predicted failure pressure times the design factor for the class location in which the affected pipeline is located; or

(C) A level not exceeding the predicted failure pressure divided by 1.1.

(ii) An operator must determine the predicted failure pressure in accordance with § 192.712. An operator must notify PHMSA in accordance with § 192.18 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) or (d) of this section and cannot provide safety through a temporary reduction in operating pressure or other action. The operator must document and keep records of the calculations and decisions used to determine the reduced operating pressure, and the implementation of the actual reduced operating pressure, for a period of 5 years after the pipeline has been remediated.

* * * * *

(b) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. For the purposes of this section, a condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable. In cases where a determination is not made within the 180-day period, the operator must notify PHMSA, in accordance with § 192.18, and provide an expected date when adequate information will become available. Notification to PHMSA does not alleviate an operator from the discovery requirements of this paragraph (b).

* * * * *

(d) *Special requirements for scheduling remediation*—(1) *Immediate repair conditions.* An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, section 7 (incorporated by reference, *see* § 192.7) in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:

(i) A metal loss anomaly where a calculation of the remaining strength of the pipe shows a predicted failure pressure determined in accordance with § 192.712(b) less than or equal to 1.1 times the MAOP at the location of the anomaly.

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) that has metal loss, cracking, or a stress riser, unless engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.

(iii) Metal loss greater than 80 percent of nominal wall regardless of dimensions.

(iv) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure determined in accordance with § 192.712(d) is less than 1.25 times the MAOP.

(v) A crack or crack-like anomaly meeting any of the following criteria:

(A) Crack depth plus any metal loss is greater than 50 percent of pipe wall thickness;

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

(C) The crack or crack-like anomaly has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.25 times the MAOP.

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

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

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.

(ii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal or helical (spiral) seam weld, unless engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.

(iii) A dent located between the 4 o'clock and 8 o'clock positions (lower ⅓ of the pipe) that has metal loss, cracking, or a stress riser, unless engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.

(iv) Metal loss anomalies where a calculation of the remaining strength of the pipe at the location of the anomaly shows a predicted failure pressure, determined in accordance with § 192.712(b), less than 1.39 times the MAOP for Class 2 locations, and less than 1.50 times the MAOP for Class 3 and 4 locations. For metal loss anomalies in Class 1 locations with a predicted failure pressure greater than 1.1 times MAOP, an operator must follow the remediation schedule specified in ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 7, Figure 4, in accordance with paragraph (c) of this section.

(v) Metal loss that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or could affect a girth weld, that has a predicted failure pressure, determined in accordance with § 192.712(b), of less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vi) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with § 192.712(d), is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vii) A crack or crack-like anomaly that has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(3) *Monitored conditions.* An operator is not required by this section to schedule remediation of the following less severe conditions but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation. Monitored indications are the least severe and do not require an operator to examine and evaluate them until the next scheduled integrity assessment interval, but if an anomaly is expected to grow to dimensions or have a predicted failure pressure (with a safety factor) meeting a 1-year condition prior to the next scheduled assessment, then the operator must repair the condition:

(i) A dent with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), located between the 4 o'clock position and the 8 o'clock position (bottom ⅓ of the pipe), and for which engineering analyses of the dent, performed in accordance with § 192.712(c), demonstrate critical strain levels are not exceeded.

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), and for which engineering analyses of the dent, performed in accordance with § 192.712(c), demonstrate critical strain levels are not exceeded.

(iii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or longitudinal or helical (spiral) seam weld, and for which engineering analyses, performed in accordance with § 192.712(c), of the dent and girth or seam weld demonstrate that critical strain levels are not exceeded.

(iv) A dent that has metal loss, cracking, or a stress riser, and where engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.

(v) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with § 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vi) A crack or crack-like anomaly for which the predicted failure pressure, determined in accordance with § 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(e) *In situ direct examination of crack defects.* Whenever an operator finds conditions that require the pipeline to be repaired, in accordance with this section, an operator must perform a direct examination of known locations of cracks or crack-like defects using technology that has been validated to detect tight cracks (equal to or less than 0.008 inches crack opening), such as inverse wave field extrapolation (IWEX), phased array ultrasonic testing (PAUT), ultrasonic testing (UT), or equivalent technology. ''In situ'' examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards, including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection for accuracy of the type of defects and pipe material being evaluated. The procedures must account for inaccuracies in evaluations and fracture mechanics models for failure pressure determinations.

■ 24. In § 192.935, paragraphs (a) and (d)(3) are revised to read as follows:

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

(a) *General requirements.* (1) An operator must take additional measures beyond those already required by this part to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. Such additional measures must be based on the risk analyses required by § 192.917. Measures that operators must consider in the analysis, if necessary, to prevent or mitigate the consequences of a pipeline failure include, but are not limited to:

(i) Correcting the root causes of past incidents to prevent recurrence;

(ii) Establishing and implementing adequate operations and maintenance processes that could increase safety;

(iii) Establishing and deploying adequate resources for the successful execution of preventive and mitigative measures;

(iv) Installing automatic shut-off valves or remote-control valves;

(v) Installing pressure transmitters on both sides of automatic shut-off valves and remote-control valves that communicate with the pipeline control center;

(vi) Installing computerized monitoring and leak detection systems;

(vii) Replacing pipe segments with pipe of heavier wall thickness or higher strength;

(viii) Conducting additional right-of-way patrols;

(ix) Conducting hydrostatic tests in areas where pipe material has quality issues or lost records;

(x) Testing to determine material mechanical and chemical properties for unknown properties that are needed to assure integrity or substantiate MAOP evaluations, including material property tests from removed pipe that is representative of the in-service pipeline;

(xi) Re-coating damaged, poorly performing, or disbonded coatings;

(xii) Performing additional depth-of-cover surveys at roads, streams, and rivers;

(xiii) Remediating inadequate depth-of-cover;

(xiv) Providing additional training to personnel on response procedures and conducting drills with local emergency responders; and

(xv) Implementing additional inspection and maintenance programs.

(2) Operators must document the risk analysis, the preventive and mitigative measures considered, and the basis for implementing or not implementing any preventive and mitigative measures considered, in accordance with § 192.947(d).

* * * * *

(d) * * *

(3) Perform instrumented leak surveys using leak detector equipment at least twice each calendar year, at intervals not exceeding 7 ½ months. For unprotected pipelines or cathodically protected pipe where electrical surveys are impractical, instrumented leak surveys must be performed at least four times each calendar year, at intervals not exceeding 4 ½ months. Electrical surveys are indirect assessments that include close interval surveys, alternating current voltage gradient surveys, direct current voltage gradient surveys, or their equivalent.

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■ 25. In § 192.941, paragraph (b)(1) and the introductory text of paragraph (b)(2) are revised to read as follows:

§ 192.941 What is a low stress reassessment?

* * * * *

(b) * * *

(1) *Cathodically protected pipe.* To address the threat of external corrosion on cathodically protected pipe in a covered segment, an operator must perform an indirect assessment on the covered segment at least once every 7 calendar years. The indirect assessment must be conducted using one of the following means: indirect examination method, such as a close interval survey; alternating current voltage gradient survey; direct current voltage gradient survey; or the equivalent of any of these methods. An operator must evaluate the cathodic protection and corrosion threat for the covered segment and include the results of each indirect assessment as part of the overall evaluation. This evaluation must also include, at a minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(2) *Unprotected pipe or cathodically protected pipe where external corrosion assessments are impractical.* If an external corrosion assessment is impractical on the covered segment an operator must—

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Issued in Washington, DC, on August 3, 2022, under authority delegated in 49 CFR 1.97.

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Deputy Administrator.

[FR Doc. 2022–17031 Filed 8–23–22; 8:45 am]

BILLING CODE 4910–60–P