STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on September 18, 2025

COMMISSIONERS PRESENT:

Rory M. Christian, Chair
James S. Alesi
David J. Valesky
John B. Maggiore
Uchenna S. Bright
Denise M. Sheehan
Radina R. Valova

CASE 24-G-0321 - In the Matter of the Rules and Regulations of the Public Service Commission, Contained in 16 NYCRR - Proposed Amendments to Chapter I, Rules of Procedure, Subchapter A, General, Part 10, Referenced Material; and Chapter III, Gas Utilities, Subchapter C, Safety, Part 255, Transmission and Distribution of Gas, to Ensure Conformance with Title 49, Code of Federal Regulations, Part 192, Transportation of Natural and Other Gas by Pipeline.

# MEMORANDUM AND RESOLUTION ADOPTING AMENDMENTS TO 16 NYCRR PART 10 AND PART 255

(Issued and Effective September 24, 2025)

BY THE COMMISSION:

## INTRODUCTION

On April 15, 2025, the Secretary to the Public Service Commission (Commission) issued a Notice Requesting Comments on Proposed Rulemaking in this proceeding regarding changes to the Commission’s gas pipeline safety regulations. The proposed changes are intended to bring Commission regulations (16 NYCRR Part 10 and Part 255) into compliance with federal regulations (49 CFR Part 192), as required pursuant to the Commission’s role as a federally certified state pipeline safety program administrator.

The proposed changes revise sections of Part 10 and several sections of Part 255, add a new section to Part 255, and make technical clarifications to various sections of Part 255. The proposed changes require some modifications to ensure they appropriately implement current federal requirements. Accordingly, by this Memorandum and Resolution, the Commission adopts the proposed changes to Parts 10 and 255 with the modifications discussed herein.

## SUMMARY OF PROPOSED CHANGES

The proposed modifications to 16 NYCRR §10.3 incorporate by reference standards for stress corrosion cracking and internal corrosion direct assessments and make other technical corrections.

The proposed modifications to 16 NYCRR Part 255 include both technical and substantive amendments, as follows. Section 255.3 is amended to add new definitions for "close interval survey," "distribution center," "dry gas or dry natural gas," "hardspot," "in-line inspection," "in-line inspection tool" or "instrumented internal inspection device," and "wrinkle bend" and to revise the definition of "transmission line." Section 255.8 is amended to revise the requirements that are applicable or not applicable to Type A and Type B gathering lines. Section 255.9 is amended to set forth the requirements that are applicable or not applicable to offshore lines. Section 255.18 is amended to require notification to PHMSA and the Department of Public Service if an operator uses an alternative technology or technique in place of what Part 255 prescribes for integrity assessments. Sections 255.319 and 255.461 are amended to require assessment of coating damage promptly after backfilling a ditch for certain pipelines and to require operators to develop remedial action plans to address any damage. Section 255.465 is amended to set forth timelines for remedial action and requirements to address inadequate cathodic protection. Section 255.473 is amended to add requirements for interference surveys. Section 255.485 is amended to require operators to calculate the remaining strength of a pipe in accordance with section 255.712. Section 255.609 is amended to require notification to the Department regarding hoop stress that is not commensurate with present class location. Section 255.611 is amended to remove the requirement that pipeline operators submit a redesign or testing program for a pipeline that does not conform to the current class location and revises testing requirements for such pipelines. Section 255.613 is amended to address pipeline inspections following extreme weather events or natural disasters. Section 255.710 is amended to prescribe repair criteria for certain pipelines outside of high consequence areas. Section 255.711 is amended to prescribe criteria for repairs to pipeline segments not covered by the operator's integrity management program. Section 255.712 is amended to prescribe repair criteria for dents and other mechanical damage. The proposal adds a new §255.714 to adopt repair criteria for onshore transmission pipelines that are outside of high consequence areas. Section 255.911 is amended to ensure the operator's integrity management program includes a management of change process in accordance with section 255.13(e). Section 255.917 is amended to add requirements regarding data gathering and integration and risk assessment for the purpose of identifying and evaluating threats to a pipeline segment located in a high consequence area. Section 255.923 is amended to require direct assessments to be done in accordance with the standards for addressing internal corrosion and stress corrosion cracking that would be adopted in this rulemaking. Section 255.927 is amended to revise the requirements for internal corrosion direct assessment plans. Section 255.929 is amended to revise the requirements for direct assessment for stress corrosion cracking and to add remediation and mitigation requirements for stress corrosion cracking. Section 255.933 is amended to add new requirements regarding repairs to pipeline. Section 255.935 is amended to adopt additional measures that a pipeline operator must take to prevent or mitigate pipeline failure. Section 255.941 is amended to address indirect assessment for cathodically protected pipe. Additionally, the proposal makes technical clarifications to §§255.13 and 255.726.

## NOTICE OF PROPOSED RULEMAKING

Pursuant to the State Administrative Procedure Act (SAPA) §202(1), a Notice of Proposed Rulemaking was published in the State Register on April 30, 2025 [SAPA No. 24-G-0321SP1]. The time for submission of comments pursuant to the Notice expired on June 30, 2025. Additionally, the Secretary issued a Notice Requesting Comments on Proposed Rulemaking, with comments due June 30, 2025.[1] On June 27, 2025, Northeast Gas Association (NGA) submitted joint utility comments on behalf of its 11 New York State natural gas local distribution company (LDC) members

[1] 24-G-0321, Notice Requesting Comments on Proposed Rulemaking (issued April 15, 2025).

in response to the Notice.[2] NGA's comments are addressed in the Discussion section below.

STATE ENVIRONMENTAL QUALITY REVIEW

The Commission determines, pursuant to the State Environmental Quality Review Act (SEQRA) and its implementing regulations, that adoption of the proposed amendments to the pipeline safety regulations is a Type II action (those previously determined not to have a significant adverse impact on the environment) within the meaning of 16 NYCRR §7.2(b)(4) and (5) as the amendments concern testing, inspection, repair and maintenance of existing facilities and safety measures for design, testing, operation and maintenance of utility facilities unrelated to siting authorization. Pursuant to 6 NYCRR §617.3(f), no SEQRA determination, Environmental Impact Statement, or findings statement are required for Type II actions.

DISCUSSION

The Commission is a federally certified state pipeline safety program administrator and is required, pursuant to 49 United States Code (USC) §60105(b)(2), to conform the pipeline safety regulations contained in 16 NYCRR to the standards in the federal pipeline safety regulations. The proposed regulations are intended to ensure consistency with the federal regulations, specifically, to reflect amendments to 49 CFR Part 192 adopted

[2] NGA states that it filed its comments on behalf of Central Hudson Gas & Electric Corporation; Consolidated Edison Company of New York, Inc.; Corning Natural Gas Corporation; Hamilton Municipal Gas; Liberty Utilities; National Fuel Gas Distribution Corporation; National Grid; New York State Electric & Gas Corporation; Orange and Rockland Utilities, Inc.; Rochester Gas and Electric Corporation; and Valley Energy Inc.

by PHMSA on August 24, 2022, and corrections to those regulations adopted on October 25, 2022, April 24, 2023, and January 15, 2025.[3] The Commission adopts the proposed regulations, with certain modifications to address the comments received, enhance clarity, and correct minor errors. The Commission explains the modifications to specific provisions of the proposed regulations below.

SIXTEEN NYCRR §255.461 – External corrosion control: protective coating

The proposed amendments to 16 NYCRR §255.461(f) require assessment of pipe coating promptly after backfill of a pipeline ditch following repair or replacement of onshore steel transmission pipelines and mains designed to operate at 125 psig (852 kPa) if the repair or replacement results in 1,000 feet or more of backfill length along the pipeline. The assessment must be done using direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or other technology that provides comparable information about the integrity of the coating. Additionally, the proposed §255.461(j) would require electrical tests of pipe coating on pipelines other than those covered by subdivision (f) to detect defects in the coating which may not be revealed by visual inspection.

NGA submitted comments noting that the revisions to 16 NYCRR §255.461(f) differ from the federal regulations at 49 CFR §192.461(f) as §255.461(f) applies to mains designed to operate at 125 psig (862 kPa) or more in addition to transmission lines. NGA states that the proposed requirement goes beyond the existing PHMSA regulations and would require local distribution

[3] 87 Fed. Reg. 52224 (August 24, 2022); 87 Fed. Reg. 64384 (October 25, 2022); 88 Fed. Reg. 24712 (April 24, 2023); 90 Fed. Reg. 3713 (January 15, 2025).

companies (LDCs) to update their operation and maintenance procedures and expand their current programs to include all mains operating above 125 psig. According to NGA, some LDCs will need to create new training programs, qualify personnel to perform the work, and acquire the necessary tools and equipment. Further, NGA states that LDCs who decide to outsource this work may need to develop contracts, work through the bidding process, and onboard third-party contractors. Because this process may take considerable time, NGA requests at least one year from the date of a Commission order before this requirement becomes effective to allow LDCs to complete all the work needed to comply. Lastly, NGA also requests an additional year to comply with the proposed §255.461(j), as subdivision (j) does not have an equivalent federal code section and applies to additional pipelines.

The Commission provides an effective date of October 1, 2026, for the provisions of §255.461(f) as they apply to mains designed to operate at 125 psig (862 kPa) or more. A new paragraph (1) is added to subdivision (f) to reflect this modification. The requirements of §255.461(f) will be effective immediately for transmission lines.

The proposed subdivision (j) is intended to continue the requirements that previously were contained in subdivisions (d) and (e). The Commission modifies the proposed §255.461(j) to ensure this subdivision encompasses existing requirements to conduct electrical tests of coating on pipelines to operate at 125 psig (862 kPa) or more prior to installation, or after installation when such tests are not practical prior to installation, and electrical tests of pipe coating on distribution mains where practical. Because these requirements exist in the current regulations, LDCs will not need additional time to come into compliance with subdivision (j), as modified.

Sixteen NYCRR §255.726 – Inactive service lines

The proposed amendments make technical corrections to two cross-references in §255.726 (b) but make no further changes to this section. Regardless, NGA provided comments on subdivisions (d) and (e) of §255.726. NGA claims that, as a result of a change to the regulations adopted in 2018,[4] requirements which previously applied only to inactive services not under cathodic protection became stand-alone requirements and may now be interpreted to apply to all inactive services including protected steel and plastic services. NGA further states that its member LDCs believe this was not the intended outcome of prior revisions and proposes that subdivisions (d) and (e) of §255.726 be relocated and included as new paragraphs under the current subdivision (b), thereby making these provisions applicable only to inactive steel service lines not under cathodic protection.

The Commission acknowledges that reviewing §255.726 of the pipeline safety regulations to ensure precision and clarity would be beneficial; however, such review is not within the purview of this rulemaking. Therefore, the Commission directs Department of Public Service Staff (Staff) to perform an analysis of §255.726 to determine if clarification is needed.

[4] Case 17-G-0368, Amendments to pipeline safety regulations contained in Title 16 NYCRR, Memorandum and Resolution Adopting Amendments to 16 NYCRR Part 255 (issued September 17, 2018).

Any suggested updates shall be addressed through a new rulemaking to provide for due process.

Sixteen NYCRR §255.917 – Identification of potential threats to pipeline

The proposed rules contain several modifications to the titles of certain technical standards that are incorporated by reference into the Commission's regulations. NGA correctly notes that the ANSI reference removed in the proposed paragraph (1) of subsection (e) of §255.917 does not align with the federal code, which retains the ANSI reference in 49 CFR §192.917(e)(1). The Commission's intent is to adopt language equivalent to the federal code in this section; therefore, the Commission modifies §255.917(e)(1) to conform to its federal analogue.

Non-substantive Revisions

Finally, the Commission makes non-substantive revisions for clarity as follows. First, the Commission modifies §10.3(a)(9) to correct punctuation and §10.3(i)(4) to correct spacing. Second, the Commission amends §255.465(f) to correct a reference to an Appendix. Third, in §255.714(c) the Commission corrects a citation to referenced material. Fourth, the Commission adds the word "pipeline" to §255.929(b)(1) where such word appears within the corresponding federal regulation at 49 CFR §192.929(b)(1).

## CONCLUSION

The modifications to Part 10 and Part 255 that we address in this memorandum and resolution incorporate federal regulatory changes that became effective on May 24, 2023, and January 15, 2025. In addition to meeting the obligations to conform the pipeline safety regulations with applicable counterpart federal regulations, the consistency and clarity resulting from the revisions will enable pipeline operators to understand their obligations and improve public safety. For these reasons, the accompanying resolution and revisions to Part 10 and Part 255 are in the public interest and are adopted.

By the Commission,

(SIGNED)

MICHELLE L. PHILLIPS
Secretary

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RESOLUTION BY THE COMMISSION

(Issued and Effective September 24, 2025)

Statutory Authority
Public Service Law
Section 66

BY THE COMMISSION:

RESOLVED:

1. That the provisions of Section 202(1) of the State Administrative Procedure Act and Section 101-a (2) of the Executive Law having been complied with, Title 16 of the Official Compilation of Codes, Rules and Regulations of the State of New York is amended,

effective upon publication of a Notice of Adoption in the State Register, by revising Chapter I, Rules of Procedure, Subchapter A, General, Part 10, Referenced Material, Section 10.3; and by revising Chapter III, Gas Utilities, Subchapter C, Safety, Part 255, Transmission and Distribution of Gas, by amending Sections 255.3, 255.8, 255.9, 255.13 255.18, 255.319, 255.461, 255.465, 255.473, 255.485, 255.609, 255.611, 255.613, 255.710, 255.711, 255.712, 255.726, 255.911, 255.917, 255.923, 255.927, 255.929, 255.933, 255.935, 255.941, and by adding Section 255.714, to read as follows (underscoring indicates new material, brackets indicate deletions):

CHAPTER I RULES OF PROCEDURE
SUBCHAPTER A General
PART 10
REFERENCED MATERIAL

Paragraph (9) of subdivision (a) of section 10.3 is amended to read as follows:

(9) ASME/ANSI B31.[,]8S-2004, "[(]Supplement to B31.8[),] on Managing System Integrity of Gas Pipelines," [(2004)] approved January 14, 2005, (ASME/ANSI B31.8S-2004), IBR approved for sections 255.714(d) and 255.933(d) of this Title;

Paragraph (1) of subdivision (i) of section 10.3 is renumbered as paragraph (4). Paragraph (2) of subdivision (i) of section 10.3 is renumbered as paragraph (1). New paragraphs (2) and (3) are added and the renumbered paragraphs (1) and (4) are amended to read as follows:

([2]1) NACE Standard Practice 0102-2010, "In-Line Inspection of Pipelines,"[(]Revised 2010-03-13[)], (NACE SP0102), IBR approved for sections 255.150(a) and 255.493 of this Title.

(2) NACE SP0204-2008, Standard Practice, "Stress Corrosion Cracking (SCC) Direct Assessment Methodology," reaffirmed September 18, 2008, (NACE SP0204); IBR approved for sections 255.923(b); 255.929(b) introductory text, (b)(1) through (3), (b)(5) introductory text, and (b)(5)(i) of this Title.

(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 sections 255.923(b); 255.927(b), (c) introductory text, and (c)(1) through (4) of this Title.

([1]4) ANSI/NACE SP0502-2010[SP 0502-2010], Standard Practice, "Pipeline External Corrosion Direct Assessment Methodology," [(]revised June 24, 2010,[); and] (NACE SP0502), IBR approved for sections 255.319(f); 255.461(h); 255.923(b); 255.925(b); 255.931(d); 255.935(b); and 255.939(a) of this Title.

CHAPTER III GAS UTILITIES
SUBCHAPTER C SAFETY
PART 255
TRANSMISSION AND DISTRIBUTION OF GAS

Paragraphs (8), (9), (10), (11), and (12) of subdivision (a) of section 255.3 are renumbered as paragraphs (9), (10), (11), (12), and (13). Paragraph (13) of subdivision (a) of section 255.3 is renumbered as paragraph (15). Paragraphs (14), (15), (16), (17), (18), (19), (20), (21), (22), and (23) of subdivision (a) of section 255.3 are renumbered as paragraphs (17), (18), (19), (20), (21), (22), (23), (24), (25), and (26). Paragraphs (24), (25), and (26) of subdivision (a) of section 255.3 are renumbered as paragraphs (28), (29), and (30). Paragraphs (27), (28), (29), (30), (31), (32), (33), (34), (35), (36), (37), (38), (39), (40), and (41) of subdivision (a) of section 255.3 are renumbered as paragraphs (33), (34), (35), (36), (37), (38), (39), (40), (41), (42), (43), (44), (45), (46), and (47). Paragraphs (42), (43), (44), (45), (46), (47), (48), (49), (50), (51), (52), (53), (54), (55), (56), (57), (58), (59), (60), (61), (62), and (63) of subdivision (a) of section 255.3 are renumbered as paragraphs (49), (50), (51), (52), (53), (54), (55), (56), (57), (58), (59), (60), (61), (62), (63), (64), (65), (66), (67), (68), (69), and (70). New paragraphs (8), (14), (16), (27), (31), (32), (48), and (71) are added and the renumbered paragraph (66) is amended to read as follows:

<u>(8) *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.</u>

(14) *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:

(i) at a metering location;

(ii) a pressure reduction location; or

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

(16) *Dry gas* or *dry natural gas* means gas above its dew point and without condensed liquids.

(27) *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 $HV_{10}$).

(31) *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.

(32) *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.

(48) *PHMSA* means the Pipeline and Hazardous Materials Safety Administration of the Federal Department of Transportation.

([59]66) *Transmission line* means a pipeline or connected series of pipelines, other than a gathering line, that:

(i) transports gas from a gathering pipeline or storage facility to a distribution center, [or] storage facility, or [directly to a] large volume [user] customer that is not down-stream from a distribution center; [or]

(ii) [operates at a hoop stress]has an MAOP of 20 percent or more of SMYS;[or ]

(iii) transports gas within a storage field[.]; or

(iv) 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.

(71) *Wrinkle bend* means a bend in the pipe that:

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

*(a)* 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

*(b)* 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.

(ii) 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 (47000—S)/10,000 +1 for psi [324—S)/69 +1 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.

Where:

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

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

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

Paragraph (2) of subdivision (c) of section 255.8 is amended to read as follows:

(2) Each Type A, Type B and Type R gathering line shall comply with the provisions listed in the third column of the table below.

| Type | Features | Applicable Regulations |
|---|---|---|
| A | In Class 1, 2, 3 or 4 location (see section 255.5 of this Part) and: - Metallic and MAOP that produces 20 percent or more of SMYS; or - MAOP of 125 psig or more | All provisions of this Part applicable to transmission lines, except sections 255.13(e), 255.150, 255.285(f), 255.319(d) through (g), 255.461(f) through (i), 255.465(d) and (f), 255.473(c), 255.485(c), 255.493, 255.506, 255.607, 255.613(c), 255.619(e), 255.624, 255.710, 255.712, and 255.901 through 255.951 of this Part. Further, operators of Type A regulated onshore gathering lines are exempt from the requirements of sections 255.179(e) through (g), 255.610, 255.827(b) through (d), 255.634, 255.635, 255.636, and 255.745(c) through (f) of this Part. |

| | | |
|---|---|---|
| | | Lastly, operators of Type A regulated onshore gathering lines are exempt from the requirements of section 255.615 of this Part (but an operator of a Type A regulated onshore gathering line must comply with the requirements of section 255.615 of this Part). |
| B | In Class 2, 3 or 4 location (see section 255.5 of this Part) and MAOP less than 125 psig. | Section 255.9 of this Part; and sections 255.801 through 255.821, 255.829 and 255.831 of this Part. Compliance with sections 255.67, 255.127, 255.179(e) and (f), 255.205, 255.227(c), 255.285(e), 255.319(d) through(g), 255.506, 255.634, and 255.636 of this Part is not required. |
| R | All other onshore gathering lines | Subdivisions 255.9(b), (c) and (d); and sections 255.801 through 255.821, 255.829 and 255.831 of this Part. |

A new subdivision (f) is added to section 255.9 to read as follows:

(f) *Offshore lines*. An operator of an offshore gathering line must comply with requirements of this Part applicable to transmission lines, except the requirements in sections 255.13(e), 255.150, 255.285(f), 255.319(d) through (g), 255.461(f) through (i), 255.465(d) and (f), 255.473(c), 255.485(c), 255.493, 255.506, 255.607, 255.613(c), 255.619(e), 255.624, 255.710, 255.712, 255.714, and 255.901 through 951 of this Part. Further, operators of offshore gathering lines are exempt from the requirements of section 255.827(b) through (d) and 255.635 of this Part. Lastly, operators of offshore gathering lines are exempt from the requirements of section 255.615 of this Part (but an operator of an offshore gathering line must comply with the requirements of section 255.615 of this Part that were in effect as of November 19, 2024).

Subdivision (e) of section 255.13 is amended to read as follows:

(e) 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[,] (as described in section 10.3 of this Title)[,] 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 sections 255.901 through 255.951 of this Part, this management of change process must be implemented by February 26, 2024. The requirements of this subdivision do not apply to gas gathering pipelines.

Subdivision (c) of section 255.18 is amended to read as follows:

(c) Unless otherwise specified, if an operator submits, [the notification is made] pursuant to sections 255.8, 255.9, 255.13, 255.179, 255.319, 255.461, 255.506, 255.607, 255.624, 255.632, 255.634, 255.636, 255.710, 255.712, 255.714, 255.745, 255.917, 255.921, 255.927, 255.933, or 255.937 of this Part [to]a notification for use of a different integrity assessment method, analytical method, compliance period, sampling approach, pipeline material, or technique ([i.]e.g., "other technology" or "alternative equivalent technology") [that differs from that]than otherwise prescribed in those sections, [the operator]that notification must [notify]be submitted to the department and PHMSA in accordance with 49 CFR section 192.18, as described in section 10.2 of this Title, at least 90 days in advance of using the other method, approach, compliance timeline, or [technology]technique. An operator may proceed to use the other method, approach, compliance timeline, or [technology]technique 91 days after [submittal]submitting [of] the notification unless it receives a letter from the department or from the PHMSA Associate Administrator for Pipeline Safety informing the operator that the department or PHMSA objects to the proposal or that the department or PHMSA requires additional time and/or information to conduct its review.

New subdivisions (c), (d), (e), (f), and (g) are added to section 255.319 to read as follows:

(c) All offshore pipe in water at least 12 feet (3.7 meters) deep but not more than 200 feet (61 meters) deep, as measured from the mean low tide must be installed so that the top of the pipe is below the natural bottom unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means.

(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 six 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 the department and PHMSA in accordance with section 255.18 of this Part at least 90 days in advance of using other technology to assess integrity of the coating under subdivision (d) of this section.

(f) An operator of an onshore steel transmission pipeline must develop a remedial action plan and apply for any necessary permits within six months of completing the assessment that identified the deficiency. An operator must repair any coating damage classified as severe (voltage drops greater than 60 percent for DCVG or 70 dBuV for ACVG) in accordance with section 4 of NACE SP0502 (as described in section 10.3 of this Title) within six months of the assessment, or as soon as practicable after obtaining necessary permits, not to exceed six 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 subdivisions (d) through (f) of this section.

Paragraph (4) of subdivision (a) of section 255.461 is amended to read as follows:

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

Subdivision (e) of section 255.461 is repealed, subdivisions (d), (f), and (g) are relettered as subdivisions (j), (d), and (e), new subdivisions (f), (g), (h), and (i) are added, and the relettered subdivision (j) is amended to read as follows:

(f) Promptly after the backfill of an onshore steel transmission, or main designed to operate at 125 psig (862 kPa) or more, 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 six 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.

(1) The provisions of this subdivision, as applicable to mains designed to operate at 125 psig (862 kPa), shall take effect October 1, 2026.

(g) An operator must notify the department and PHMSA in accordance with section 255.18 of this Part at least 90 days in advance of using other technology to assess integrity of the coating under subdivision (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 six 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 dBuV for ACVG) in accordance with section 4 of NACE SP0502 (as described in section 10.3 of this Title) within six months of the assessment, or as soon as practicable after obtaining necessary permits, not to exceed six 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 subdivisions (f) through (h) of this section.

([d]j) Electrical tests appropriate for the type of coating shall be used on pipelines to operate at 125 psig (862 kPa) or more to detect defects in the coating which may not be revealed by a visual inspection prior to installation. Where such tests are not practical, electrical tests, after installation, shall be conducted. Additionally, electrical tests of pipe coating on distribution mains shall be conducted where practical.

The title of section 255.465 is amended, subdivision (f) is relettered subdivision (g), subdivision (d) and the relettered subdivision (g) are amended, and a new subdivision (f) is added to read as follows:

§ 255.465 External corrosion control: monitoring and remediation.

(d) Each operator [shall take prompt remedial action to] must promptly correct any deficiencies indicated by the [monitoring] inspection and testing required by subdivisions (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 six 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 six 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 14-D to this Title.

(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 five 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 subdivision (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.

([f]g) The operator shall determine the areas of active corrosion by electrical survey, or where electrical survey is impractical, by using the required leakage survey (see section 255.723(b) of this Part) in conjunction with an analysis of the corrosion and leak history records, or by other approved means.

A new subdivision (c) is added to section 255.473 to read as follows:

(c) For onshore gas transmission pipelines, the program required by subdivision (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 alternating current (AC), 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 six 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.

Section 255.485 is amended to read as follows:

§ 255.485 Remedial measures: transmission lines.

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

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

(c) *Calculating remaining strength.* Under subdivisions (a) and (b) of this section, strength of transmission line pipe based on actual remaining wall thickness must be determined [by the procedure in ASME B31G (as described in Section 10.3 of this Title), or the procedure PRCI PR 3-805 (R-STRENG) (as described in Section 10.3 of this Title). Both procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations prescribed in the procedures] and documented in accordance with section 255.712 of this Part.

Section 255.609 is amended to read as follows:

§ 255.609 Change in class location: required study.

(a)[At least once every five years or w]Whenever an increase in population density indicates [either] a change in class location for a segment of an existing steel pipeline operating at a hoop stress that is more than 40 percent of SMYS, or indicates that the hoop stress corresponding to the established maximum allowable operating pressure for a segment of existing pipeline is not commensurate with the present class location, the operator shall immediately make a study to determine:

(1[a]) the present class location for the segment involved;

(2[b]) the design, construction, and testing procedures followed in the original construction, and a comparison of these procedures with those required for the present class location by the applicable provisions of this Part;

(3[c]) the physical condition of the segment to the extent it can be ascertained from available records;

(4[d]) the operating and maintenance history of the segment;

(5[e]) the maximum actual operating pressure and the corresponding operating hoop stress, taking pressure gradient into account, for the segment of pipeline involved; and

(6[f]) the actual area affected by the population density increase, and physical barriers or other factors which may limit further expansion of the more densely populated area.

(b) Notification to the department shall be made within 60 days of an operator determining that the hoop stress corresponding to the established maximum allowable operating pressure for a segment of existing pipeline is not commensurate with the present class location.

Section 255.611 is amended to read as follows:

§ 255.611 Change in class location: confirmation or revision of maximum allowable operating pressure.

[(a) Within 60 days after the required study is completed, the operator shall submit a program for redesigning and/or testing the respective pipeline segments, or appropriate reduction of the maximum certified operating pressures thereof, to conform to the respective then current class locations, in accordance with this Part, or declare that the design, testing, and operation of the respective pipeline segments conform to the respective then current class locations.]

(a[b]) [Where]If the hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with the present class location, and the segment is in satisfactory physical condition, the maximum allowable operating pressure of that segment of pipeline must be confirmed or revised according to one of the following requirements:[.]

(1) If the segment involved has been previously tested in place [to at least 90 percent of its SMYS ]for a period of not less than eight hours, [the maximum allowable operating pressure must be confirmed or reduced so that the corresponding hoop stress will not exceed 72 percent of SMYS in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.]the maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in Class 3 locations, or 0.555 times the test pressure in Class 4 locations. The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

(2) [If] The maximum allowable pressure of the segment involved [has not been previously tested in place as described in paragraph (1) of this subdivision, the maximum allowable operating pressure] must be reduced so that the corresponding hoop stress is not more than that allowed by this Part for new segments of pipelines in the existing class location.

(3) [If t] The segment [of pipeline] involved [has not been qualified for operation under paragraph (1) or (2) of this subdivision, it] must be tested in accordance with the applicable requirements of sections 255.503 through 255.517 of this Part, and its maximum allowable

operating pressure must then be established [so as to be equal to or less than each of] according to the following criteria:

(i) The maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations, 0.667 times the test pressure for Class 3 locations, and 0.555 times the test pressure for Class 4 locations.

[(ii) The maximum allowable operating pressure confirmed or revised in accordance with the section, may not exceed the maximum allowable operating pressure established before the confirmation or revision.]

(ii[iii]) The corresponding hoop stress may not exceed 72 percent of SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in class 4 locations.

(b) The maximum allowable operating pressure confirmed or revised in accordance with this section, may not exceed the maximum allowable operating pressure established before the confirmation or revision.

(c) Confirmation or revision of the maximum allowable operating pressure of a segment of pipeline in accordance with this section does not preclude the application of sections 255.553 and 255.555 of this Part.

(d) Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under section 255.609 of this Part must be completed within [18]24 months of the change in class location. Pressure reduction under paragraphs (1) or (2) of subdivision (a) of this section within the 24-month period does not preclude establishing a maximum allowable operating pressure under paragraph (3) of subdivision (a) of this section at a later date.

[(e) Pressure reduction under paragraph (b)(2) of this section within the 18-month period does not preclude establishing a maximum allowable operating pressure under paragraph (b)(3) of this section at a later date.]

A new subdivision (c) is added to section 255.613 to read as follows:

(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.

(2) An operator must commence the inspection required by this subdivision 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 (1) of this subdivision are available. If an operator is unable to commence the inspection due to the unavailability of personnel or equipment, the operator must notify the department and PHMSA 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 this subdivision. 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.

Subdivision (f) of section 255.710 is amended to read as follows:

(f) *Remediation*. An operator must comply with the requirements in sections 255.485, 255.711, 255.712, [and ]255.713, and 255.714 of this Part, where applicable, if a condition that could adversely affect the safe operation of a pipeline is discovered.

Paragraphs (1) and (2) of subdivision (b) of section 255.711 are amended to read as follows:

(1) [non ]Non-integrity management repairs: [The operator must make permanent repairs as soon as feasible.]

(i) Non-integrity management repairs for gathering lines and offshore transmission lines: For gathering lines subject to this section in accordance with section 255.9 of this Part 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 section 255.9 of this Part and offshore transmission lines, whenever an operator discovers any condition that could adversely affect the safe operation of a pipeline segment not covered by an integrity management program in sections 255.901 through 255.951 of this Part, it must correct the condition as prescribed in section 255.714 of this Part.

(2) [i]Integrity management repairs[.]: When an operator discovers a condition on a pipeline covered under [Subpart O]sections 255.901 through 255.951 of this Part [-]Gas Transmission Pipeline Integrity Management, the operator must remediate the condition as prescribed by section 255.933(d) of this Part.

The title of section 255.712 is amended and new paragraphs (1) and (2) are added to subdivision (b) of section 255.712 to read as follows:

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

(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 this subdivision, the operator must notify the department and PHMSA in advance in accordance with section 255.18 of this Part.

(2) The notification provided for by paragraph (1) of this subdivision 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.

New subdivisions (c) and (h) are added to section 255.712 to read as follows:

(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 sections 255.713, 255.714, or 255.933 of this Part, 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 five 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 sections 255.713, 255.714, or 255.933 of this Part, as applicable.

(11) An operator using an engineering critical assessment procedure, other technologies, or techniques to comply with subdivision (c) of this section must submit advance notification to the department and PHMSA, with the relevant procedures, in accordance with section 255.18 of this Part.

(h) *Reassessments*. If an operator uses an engineering critical assessment method in accordance with subdivisions (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 seven years in accordance with section 255.939(a) of this Part, unless the safety factor is expected to go below what is specified in subdivisions (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 section 255.710(b) of this Part,

unless the anomaly safety factor is expected to go below what is specified in subdivisions (c) or (d) of this section.

A new section 255.714 is added to read as follows:

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

(a) *Applicability*. This section applies to onshore transmission pipelines not subject to the repair criteria in sections 255.901 through 255.951 of this Part. Pipeline segments that are located in high consequence areas, as defined in section 255.903 of this Part, must comply with the applicable actions specified by the integrity management requirements in sections 255.901 through 255.951 of this Part.

(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 section 255.712 of this Part 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 section 255.607 of this Part. Until documented material properties are available, the operator must use the conservative assumptions in either section 255.712(e)(2) of this Part or, if appropriate following a pressure test, in section 255.712(d)(3) of this Part.

(c) *Schedule for evaluation and remediation*. An operator must remediate conditions according to a schedule that prioritizes the conditions for evaluation and remediation. Unless subdivision (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 B31.8S (as described in section 10.3 of this Title) Section 7, Figure 7.2.1-1. 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 subdivision (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 section 255.105 of this Part 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's evaluation and remediation schedule for immediate repair conditions must follow section 7 of ASME/ANSI B31.8S-2004 (as described in section 10.3 of this Title). 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 section 255.712(b) of this Part, 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 2/3 of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis performed in accordance with section 255.712(c) of this Part 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 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 section 255.712(d) of this Part 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.

(vi) An indication or anomaly that, in the judgement 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 two years of discovery:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than six percent diameter (greater than 0.50 inch in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless an engineering analysis performed in accordance with section 255.712(c) demonstrates critical strain levels are not exceeded.

(ii) A dent with a depth greater than two percent of the pipeline diameter (0.250 inch 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 section 255.712(c) of this Part demonstrates critical strain levels are not exceeded.

(iii) A dent located between the 4 o'clock and 8 o'clock positions (lower 1/3 of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis performed in accordance with section 255.712(c) of this Part 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 section 255.712(b) of this Part 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 predicated failure pressure greater than 1.1 times MAOP, an operator must follow the remediation schedule specified in ASME/ANSI B31.8S-2004 (as described in section 10.3 of this Title), section 7, Figure 4, as specified in subdivision (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 section 255.712(b) of this Part, 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 section 255.611 of this Part, 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 section 255.712(d) of this Part 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 section 255.611 of this Part, 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 section 255.712(d) of this Part, 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 section 255.611 of this Part, 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 4 o'clock and 8 o'clock positions (bottom 1/3 of the pipe) with a depth greater than six percent of the pipeline diameter (greater than 0.50 inch in depth for a pipeline diameter less than NPS 12), and where an engineering analysis, performed in accordance with section 255.712(c) of this Part, demonstrates critical strain levels are not exceeded.

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than six percent of the pipeline diameter (greater than 0.50 inch in depth for a pipeline diameter less than NPS 12), and where an engineering analysis performed in accordance with section 255.712(c) of this Part determines that critical strain levels are not exceeded.

(iii) A dent with a depth greater than two percent of the pipeline diameter (0.250 inch 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 section 255.712(c) of this Part, 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 section 255.712(c) of this Part 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 section 255.712(d) of this Part, 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 section 255.611 of this Part, 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 section 255.712(d) of this Part, 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 section 255.611 of this Part, 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 (1) of subdivision (d) 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 (2) of subdivision (d) 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 the department and PHMSA in accordance with section 255.18 of this Part if it cannot meet the schedule for evaluation and remediation required under subdivision (c) or (d) of this section and cannot provide safety through a temporary reduction in operating pressure or other action. Notification to the department and 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 this subdivision, exceeds 365 days, an operator must notify the department and PHMSA in accordance with section 255.18 of this Part 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 five years after the pipeline has been repaired.

(f) *Other conditions*. Unless another timeframe is specified in subdivision (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 inch 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 section 255.712 of this Part.

Paragraphs (1) and (2) of subdivision (b) of section 255.726 are amended to read as follows:

(1) During the third year of inactivity, the operator must conduct a survey for potential future use and, if there is no definite plan for future use, disconnect the service at the main or in compliance with subdivision ([d]c) of this section, purge the service and seal the open end.

(2) Inactive service lines for which there is a definite plan for future use may remain under the conditions established by section 255.727(d) of this Part for an additional three-year period provided the operator either reactivates the service or disconnects the service at the main or in compliance with subdivision ([d]c) of this section, purges the service and seals the open ends by the end of the sixth year of inactivity.

Subdivision (k) of section 255.911 is amended to read as follows:

(k) A management of change process as [outlined in ASME/ANSI B31.8S, section 11] required by section 255.13(e) of this Part.

Subdivisions (a), (b), (c), and (d) of section 255.917 are amended to read as follows:

(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 B31.8S (as described in section 10.3 of this Title), 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) [Static or resident]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 this data gathering and integration, an operator must follow the requirements in ASME[/ANSI] B31.8S, section 4.[ At a minimum, an operator 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, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline.] 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 must gather and evaluate the set of data listed in paragraph (1) of subdivision (b) of this section. The evaluation must analyze both the covered segment and similar noncovered 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 section 255.827 of this Part 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 section 255.459 of this Part), including the results of any non-destructive examinations of the pipe, seam, or girth weld (e.g., 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 judgement 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 [considers the identified threats for each covered segment. An operator must use the risk assessment to prioritize the covered segments for the baseline and continual reassessments (sections 255.919, 255.921, 255.937 of this Part), 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 [what] additional preventive and mitigative measures [are] needed for each covered segment in accordance with [(]section 255.935 of this Part[) for the covered segment.] and periodically evaluate the integrity of each covered pipeline segment in accordance with section 255.937 of this Part. 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.

(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.

Paragraphs (1) and (4) of subdivision (e) of section 255.917 are amended to read as follows:

(1) *Third party damage*. An operator must utilize the data integration required in subdivision (b) of this section and ASME/ANSI B31.8S, Appendix A[7]-8 to determine the susceptibility of each covered segment to the threat of third party damage. If an operator identifies the threat of third party damage, the operator must implement comprehensive additional preventive measures in accordance with section 255.935 of this Part and monitor the effectiveness of the preventive measures. If, in conducting a baseline assessment under section 255.921 of this Part, or a reassessment under section 255.937 of this Part, an operator uses an internal inspection tool or external corrosion direct assessment, the operator must integrate data from these assessments with data related to any encroachment or foreign line crossing on the covered segment, to define where potential indications of third party damage may exist in the covered segment. An operator must also have procedures in its integrity management program addressing actions it will take to respond to findings from this data integration.

(4) *Electric Resistance Welded (ERW) pipe*. If a covered pipeline segment contains low frequency ERW pipe, lap welded pipe, pipe with longitudinal joint factor less than 1.0 as defined in section 255.113 of this Part, or other pipe that satisfies the conditions specified in ASME[/ANSI] B31.8S, Appendices A-[4]5.3 and A-[4]5.4, and any covered or non-covered segment in the pipeline system with such pipe has experienced seam failure (including seam cracking and selective seam weld corrosion), or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years (including abnormal operation as defined in section 255.605(r) of this Part), or MAOP has been increased, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high-risk segment for the baseline assessment or a subsequent reassessment. Pipe with seam cracks must be evaluated using fracture mechanics modeling for

failure stress pressures and cyclic fatigue crack growth analysis to estimate the remaining life of the pipe in accordance with section 255.712 of this Part.

Paragraphs (2) and (3) of subdivision (b) of section 255.923 are amended to read as follows:

(2) NACE SP0206 [ASME/ANSI B31.8S, section 6.4 and Appendix B2] (as described in section 10.3 of this Title), and section 255.927 of this Part if addressing internal corrosion (IC).

(3) NACE SP0204[ASME/ANSI B31.8S, Appendix A3] (as described in section 10.3 of this Title), and section 255.929 of this Part if addressing stress corrosion cracking (SCC).

Subdivisions (b) and (c) of section 255.927 are amended to read as follows:

(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 [ASME/ANSI B31.8S]NACE SP0206 (as described in section 10.3 of this Title)[, section 6.4 and Appendix B2]. The Dry Gas Internal Corrosion Direct Assessment (DG-ICDA) process described in this section applies only for a segment of pipe transporting [nominally ]normally dry natural gas, and not for a segment with electrolyte [nominally ]normally present in the gas stream. If an operator uses ICDA to assess a covered segment operating with electrolyte present in the gas stream, the operator must develop a plan that demonstrates how it will conduct ICDA in the segment to effectively address internal corrosion, and must [provide notification ]notify the department and PHMSA in accordance with section 255.[921 (a)(4) or 255.937(c)(4) ]18 of this Part. 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 [provides for preassessment, identification of ICDA regions and excavation locations, detailed examination of pipe at excavation locations, and post-assessment evaluation and monitoring] meets NACE SP0206 (as described in section 10.3 of this Title) 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*.[ In the preassessment stage, an operator must gather and integrate data and information needed to evaluate the feasibility of ICDA for the covered segment, and to support use of a model to identify the locations along the pipe segment where electrolyte may accumulate, to identify ICDA regions, and to identify areas within the covered segment where liquids may potentially be entrained. This data and information includes, but is not limited to:] An operator must comply with NACE SP0206 (as described in section 10.3 of this Title) in conducting the preassessment step of the ICDA process.

[(i) all data elements listed in Appendix A2 of ASME/ANSI B31.8S;

(ii) information needed to support use of a model that an operator must use to identify areas along the pipeline where internal corrosion is most likely to occur. (See subdivision (a) of this section.) This information, includes, but is not limited to, location of all gas input and withdrawal points on the line; location of all low points on covered segments such as sags, drips, inclines, valves, manifolds, dead-legs, and traps; the elevation profile of the pipeline in sufficient detail that angles of inclination can be calculated for all pipe segments; and the diameter of the pipeline, and the range of expected gas velocities in the pipeline;

(iii) operating experience data that would indicate historic upsets in gas conditions, locations where these upsets have occurred, and potential damage resulting from these upset conditions; and

(iv) information on covered segments where cleaning pigs may not have been used or where cleaning pigs may deposit electrolytes.]

(2) [ICDA region identification]*Indirect inspection*. An operator['s plan] must [identify where all ICDA regions are located in the transmission system, in which covered segments are located. 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 and where further evaluation is needed. An ICDA region may encompass one or more covered segments. In the identification process,]comply with NACE SP0206 (as described in section 10.3 of this Title), and the following additional requirements, in conducting the Indirect Inspection step of the ICDA process.[,] [a]An operator must [use the model in GRI 02-0057, "Internal Corrosion Direct Assessment of Gas Transmission Pipelines-Methodology," (as described in Section 10.3 of this Title).] explicitly document the results of its feasibility assessment as required by NACE SP0206, section 3.3 (as described in section 10.3 of this Title); 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, [An]the operator[may use another model if the operator demonstrates it is equivalent to the one shown in GRI 02-0057. A model must consider changes in pipe diameter, locations where gas enters a line (potential to introduce liquid) and locations downstream of gas draw-offs (where gas velocity is reduced) to define the critical pipe angle of inclination above which water film cannot be transported by the gas] 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) [Identification or locations for excavation and direct examination]*Detailed Examination*. An operator['s plan] must [identify the locations where internal corrosion is most likely in each ICDA Region] comply with NACE SP0206 (as described in section 10.3 of this Title) in conducting the detailed examination step of the ICDA process. [In the location identification 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 within a covered segment and must perform a [direct] 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., sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA Region. The second location must be further downstream, within a covered segment, near the end of the ICDA Region. [If] Whenever corrosion is found during ICDA [exists] at [either]any location, the operator must:

(i) [e]Evaluate the severity of the defect (remaining strength) and remediate the defect in accordance with section 255.933 of this Part if the condition is in a covered segment, or in accordance with sections 255.485 and 255.714 of this Part if the condition is not in a covered segment.

(ii) [as part of the operator's current integrity assessment either perform additional excavations in each covered segment] 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. [or use an alternative assessment method allowed by sections 255.901 through 255.951 to assess the line pipe in each covered segment within the ICDA region for 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 (3) of subdivision (c) of this section, two additional detailed examinations must be conducted within the covered segment. [; and]

(iii) Expand the detailed examination program to [E]evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator's pipeline system with similar characteristics to the ICDA region [containing the covered segment] in which the corrosion was found, and [as appropriate,] remediate [the conditions the operator finds] identified instances of internal corrosion in accordance with section 255.933 or sections 255.485 and 255.714 of this Part, as appropriate.

(4) *Post-assessment evaluation and monitoring*. An operator['s plan must provide for evaluating the effectiveness] must comply with NACE SP0206 (as described in section 10.3 of this Title) in performing the post-assessment step of the ICDA process [and continued monitoring of covered segments where internal corrosion has been identified]. In addition to complying with NACE SP0206, [T]the evaluation and monitoring process must also include[s]:

(i) an [evaluating] 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 section 255.939 of this Part. An operator must carry out this evaluation within [a]one year of conducting an ICDA; [and]

(ii) [continually monitoring each covered segment where internal corrosion has been identified using techniques such as coupons, UT sensors or electronic probes, 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 sections 255.901 through 255.951, and risk factors specific to the covered segment. If an operator finds any evidence of corrosion products in the covered segment, 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 section 255.933 of this

Part:]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

[(A) conduct excavations of covered segments at locations downstream from where the electrolyte might have entered the pipe; or

(B) assess the covered segment using another integrity assessment method allowed by sections 255.901 through 255.951 of this Part.]

(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 sections 255.901 through 255.951 of this Part 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 seven and one-half 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 section 255.933 or sections 255.485 and 255.714 of this Part, 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; or

(*b*) assess the covered segment using another integrity assessment method allowed by this Part.

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

(i) criteria an operator will apply in making key decisions ([e.g., ]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[ for applying more restrictive criteria when conducting ICDA for the first time on a] that the analysis be carried out on the entire pipeline in which covered segments are present, except that application of the remediation criteria of section 255.933 of this Part may be limited to covered segments.[and that become less stringent as the operator gains experience; and

(iii) provisions that analysis be carried out on the entire pipeline in which covered segments are present, expect that application of the remediation criteria of section 255.933 may be limited to covered segments.]

Section 255.929 is amended to read as follows:

§255.929 Direct assessment for stress corrosion cracking (SCCDA)

(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)[ primarily] by systematically gathering and analyzing excavation data [for] 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 [to] for addressing SCC [stress corrosion cracking] in a covered pipeline segment must [have a plan that provides, at minimum, ]develop and follow an SCCDA plan that meets NACE SP0204 (as described in section 10.3 of this Title) 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 (as described in section 10.3 of this Title). This process must 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 (as described in section 10.3 of this Title) indicate the potential for SCC [during the conduct of its pipeline operations where the criteria in ASME/ANSI B31.8S (as described in Section 10.3 of this Title), appendix A3.3 indicate the potential for SCC]. This data gathering process must be conducted in accordance with NACE SP0204, section 5.3 (as described in section 10.3 of this Title), and must include[s], at minimum,[ the data specified in ASME/ANSI B31.8S, appendix A3.] all data listed in NACE SP0204, Table 2 (as described in section 10.3 of this Title). 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) [Assessment method]*Indirect inspection*. In addition to NACE SP0204, [T]the plan's procedures for indirect inspection must [provide that if conditions for SCC are identified in a covered segment, an operator must assess the covered segment using an integrity assessment method specified in ASME/ANSI B31.8S, appendix A3, and remediate the threat in accordance with ASME/ANSI B31.8S, appendix A3, section A3.4 ]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 subparagraph (ii) of this paragraph; 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 section 255.712 of this Part and that meets the design requirements of section 255.111 of this

Part, 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 section 255.607 of this Part, if applicable.

(ii) Performing a spike pressure test in accordance with section 255.506 of this Part based upon the class location of the pipeline segment. The MAOP must be no greater than the test pressure specified in section 255.506(a) of this Part divided by: 1.39 for Class 1 locations and Class 2 locations that contain Class 1 pipe that has been uprated in accordance with section 255.611 of this Part; 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 subparagraph (i) of this paragraph.

(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 section 255.939 of this Part. 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 (as described in section 10.3 of this Title);

(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.

Subdivision (a) of section 255.933 and paragraph (1) of subdivision (a) of section 255.933 are amended to read as follows:

(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 section 255.607 of this Part. Until documented material properties are available, the operator must use the conservative assumptions in either section 255.712(e)(2) of this Part or, if appropriate following a pressure test, in section 255.712(d)(3) of this Part.

(1) *Temporary pressure reduction*.[If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must determine any temporary reduction in operating pressure required by this section using ASME/ANSI B31G (as described in Section 10.3 of this Title); R-STRENG (as described in Section 10.3 of this Title); or by reducing the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered. An operator must notify the Department and PHMSA in accordance with section 255.18 if it cannot meet the schedule for evaluation and remediation required under Paragraph (c) of this section and cannot provide safety through a temporary reduction in operating pressure or through another action.]

(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 section 255.712 of this Part. An operator must notify the department and PHMSA in accordance with section 255.18 of this Part if it cannot meet the schedule for evaluation and remediation required under subdivisions (c) and (d) of this section and cannot provide safety through a temporary reduction in operating pressure or through another 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 five years after the pipeline has been remediated.

Subdivision (b) of section 255.933 is amended to read as follows:

(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[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 the department and PHMSA, in accordance with section 255.18 of this Part, and provide an expected date when adequate information will become available. Notification to the department and PHMSA does not alleviate an operator from the discovery requirements of this subdivision.

Subparagraphs (i), (ii), and (iii) of paragraph (1) of subdivision (d) of section 255.933 are amended and new subparagraphs (vi), (v), and (vi) are added to read as follows:

(i) A metal loss anomaly where a calculation of the remaining strength of the pipe shows a predicted failure pressure determined in accordance with section 255.712(b) of this Part less than or equal to 1.1 times the MAOP[maximum allowable operating pressure] at the location of the anomaly. [Suitable remaining strength calculation methods include ASME/ANSI B31G (R-STRENG); or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in Section 10.3 of this Title;]

(ii) A dent [that has any indication of ]located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) that has metal loss, cracking or a stress riser, unless engineering analyses performed in accordance with section 255.712(c) of this Part demonstrate critical strain levels are not exceeded.

(iii) [An indication or anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action ]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 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 section 255.712(d) of this Part 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; or

(*b*) crack depth plus any metal loss is greater than the inspection tool's maximum measurable depth.

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

Subparagraphs (i) and (ii) of paragraph (2) of subdivision (d) of section 255.933 are amended and new subparagraphs (iii), (iv), (v), (vi), and (vii) are added to read as follows:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than six percent of the pipeline diameter (greater than 0.50 inch (13 millimeters) in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless engineering analyses performed in accordance with section 255.712(c) of this Part demonstrate critical strain levels are not exceeded.

(ii) A dent with a depth greater than two percent of the pipeline's diameter (0.250 inch (6 millimeters) 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 section 255.712(c) of this Part demonstrate critical strain levels are not exceeded.

(iii) A dent located between the 4 o'clock and 8 o'clock positions (lower 1/3 of the pipe) that has metal loss, cracking, or a stress riser, unless engineering analyses performed in accordance with section 255.712(c) of this Part 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 section 255.712(b) of this Part, 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-2004 (as described in section 10.3 of this title), section 7, Figure 4, in accordance with subdivision (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 section 255.712(b) of this Part, 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 section 255.611 of this Part, 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 section 255.712(d) of this Part, 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 section 255.611 of this Part, 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 section 255.712(d) of this Part, 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 section 255.611 of this Part, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

Subparagraphs (i), (ii), and (iii) of paragraph (3) of subdivision (d) of section 255.933 are amended and new subparagraphs (iv), (v), and (vi) are added to read as follows:

(3) *Monitored conditions*. An operator[does not have] is not required by this section to schedule remediation of the following less severe conditions [for remediation,] 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 one-year condition prior to the next scheduled assessment, then the operator must repair the condition:

(i) A dent with a depth greater than six percent of the pipeline diameter (greater than 0.50 inch (13 millimeters) in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom 1/3 of the pipe), and for which engineering analyses of the dent, performed in accordance with section 255.712(c) of this Part, demonstrate critical strain levels are not exceeded.

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than six percent of the pipeline diameter (greater than 0.50 inch (13 millimeters) in depth for a pipeline diameter less than[ nominal/pipe/size(]NPS[)] 12), and for which engineering analyses of the dent, performed in accordance with section 255.712(c) of this Part, demonstrate critical strain levels are not exceeded.

(iii) A dent with a depth greater than two percent of the pipeline's diameter (0.250 inch (6 millimeters) depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal or helical (spiral) seam weld, and for which engineering analyses, performed in accordance with section 255.712(c) of this Part, of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. [These analyses must consider weld properties.]

(iv) A dent that has metal loss, cracking, or a stress riser, and where engineering analyses performed in accordance with section 255.712(c) of this Part 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 section 255.712(d) of this Part, 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 section 255.611 of this Part, 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 section 255.712(d) of this Part, 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 section 255.611 of this Part, or greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

A new subdivision (e) is added to section 255.933 to read as follows:

(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 inch 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.

Subdivision (a) of section 255.935 is amended to read as follows:

(a) *General Requirements*.

[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. An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (See section 255.917) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (as described in Section 10.3 of this Title), section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to, installing automatic shut-off valves or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs.]

(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 section 255.917 of this Part. 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 section 255.947(d) of this Part.

Paragraph (3) of subdivision (d) of section 255.935 is amended to read as follows:

(3) Perform instrumented leak surveys using leak detector equipment at least twice each calendar year, at intervals not exceeding [7-1/2]seven and one-half months. [(four times each calendar year at intervals not exceeding 4-1/2 months f]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 four and one-half months. Electrical surveys are indirect assessments that include close interval surveys, alternating current voltage gradient surveys, direct current voltage gradient surveys, or their equivalent.

Paragraphs (1) and (2) of subdivision (b) of section 255.941 are amended to read as follows:

(1) *Cathodically protected pipe*. To address the threat of external corrosion on cathodically protected pipe in a covered segment, an operator must perform an [electrical survey (i.e. indirect examination tool/method)] indirect assessment [at least every seven years ]on the covered segment at least once every seven calendar years.[ An operator must use the results of each survey as part of an overall evaluation of the cathodic protection and corrosion threat for the covered segment.] 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[consider] 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 [electrical surveys]external corrosion assessments are impractical*. If an [electrical survey]external corrosion assessment is impractical on the covered segment an operator must: