**NOTICE OF INTENT**

**Department of Energy and Natural Resources**
**Office of Conservation**

Pipeline Safety
(LAC 43:XI.Chapter 35, LAC 43:XIII:Chapters 1-35 & LAC 33:V:Chapters 30105-30452)

The Department Energy and Natural Resources, Office of Conservation proposes to amend LAC43:XIII & LAC 33:V in accordance with the provisions of the Administrative Procedure Act, R.S. 49:950 et seq., and pursuant to the power delegated under the laws of the state of Louisiana.

The proposed rule changes modify existing Carbon Dioxide rules and codify exiting federal regulations that are required as a part of the Department Energy and Natural Resources certification agreement with the US Department of Transportation and are intended to adopt existing federal regulations as state regulations.

# Title 43
# NATURAL RESOURCES
# Part XI. Office of Conservation
## Subpart 4. Carbon Dioxide
## Chapter 35. Requirements

### §3501. Operation, Construction, Extension, Acquisition, Interconnection or Abandonment of Carbon Dioxide Transmission Facilities (Formerly §703)

A. – F. …

1. that the applicant is able and willing to perform the services proposed and to conform to all of the applicable provisions of Title 30 of the Louisiana Revised Statutes and the applicable rules and regulations in Title 43 and Title 33 of the Louisiana Administrative Code;

2. that the applicant proposes to construct and/or operate facilities for the transmission of carbon dioxide for injection in connection with a secondary or tertiary recovery project for the enhanced recovery of liquid or gaseous hydrocarbons or a geologic sequestration project; and

3. that the proposed facilities are reasonably necessary to serve a secondary or tertiary recovery project or geologic sequestration project.

G. …

1. that the applicant is able and willing to perform the services proposed and to conform to all of the applicable provisions of Title 30 of the Louisiana Revised Statutes and the applicable rules and regulations in Title 43 and Title 33 of the Louisiana Administrative Code;

G.2. …

3. that the applicant proposes to construct and/or operate facilities for the transmission of carbon dioxide for injection in connection with a secondary or tertiary recovery project for the enhanced recovery of liquid or gaseous hydrocarbons or geologic sequestration project which has been approved by the commissioner pursuant to the provisions of Title 30 of the Louisiana Revised Statutes and the applicable rules and regulations in Title 43 and Title 33 Title 43 and Title 33 of the Louisiana Administrative Code; and

G.4. – H.…

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:4(C)(17), R.S. 30:1104(A), and R.S. 30:1107.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 12:115 (February 1986), repromulgated LR 49:303 (February 2023), amended LR 49:904 (May 2023), amended LR 49:1096 (June 2023), LR 50:35 (January 2024), LR 50:

# Part XIII. Office of Conservation—Pipeline Safety
## Subpart 1. General Provisions

### §101. Applicability

A. …

B. Notwithstanding the criteria in §101.A above, this regulation shall apply only to those persons identified in the certification or agreement in effect, pursuant to Section 5 of the Natural Gas Pipeline Safety Act of 1968, as amended (Federal Act), duly executed by the Secretary of the Department of Energy and Natural Resources and the United States Secretary of Transportation.

C. …

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:217 (April 1983), amended LR 10:508 (July 1984), LR 18:852 (August 1992), LR 20:442 (April 1994), LR 27:1535 (September 2001), LR 30:1219 (June 2004), LR 50:

## Subpart 3. Transportation of Natural Gas or Other Gas by Pipeline: Minimum Safety Standards [49 CFR Part 192]

## Chapter 5. General [49 CFR Part 192 Subpart A]

### §503. Definitions [49 CFR 192.3]

A. …

* * *

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

* * *

*Distribution Center***—**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:

a. at a metering location;

b. a pressure reduction location; or

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

d. where downstream pipeline has a maximum allowable operating pressure established under §2719 by the operator below 20 percent SMYS and cannot be classified as a transmission line.

* * *

*Entirely Replaced Onshore Transmission Pipeline Segments L*—for the purposes of §§1139 and 2734, where 2 or more miles, in the aggregate, of onshore transmission pipeline have been replaced within any 5 contiguous miles of pipeline within any 24-month period. This definition does not apply to any gathering line.

* * *

*Dry Gas or Dry Natural Gas*—gas above its dew point and without condensed liquids.

* * *

*Hard Spot*—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 $HV_{10}$).

* * *

*Notification of Potential Rupture*—the notification to, or observation by, an operator of indicia identified in §2735 of a potential unintentional or uncontrolled release of a large volume of gas from a pipeline. This definition does not apply to any gathering line.

* * *

*Rupture-Mitigation Valve* (RMV)—an automatic shut-off valve (ASV) or a remote-control valve (RCV) that a pipeline operator uses to minimize the volume of gas released from the pipeline and to mitigate the consequences of a rupture. This definition does not apply to any gathering line.

* * *

*Transmission Line*—a pipeline or connected series of pipelines, other than a gathering line, that:

a. Transports gas from a gathering pipeline or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center;

b. has an MAOP of 20 percent or more of SMYS

c. transports gas within a storage field; or

d. is voluntarily designated by the operator as a transmission pipeline.

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

* * *

*Wrinkle Bend—a bend in the pipe that:*

a. was formed in the field during construction such that the inside radius of the bend has one or more ripples with:

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

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

b. 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)/10000 +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).

* * *

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 30:1224 (June 2004), amended LR 31:679 (March 2005), LR 33:474 (March 2007), LR 35:2800 (December 2009), LR 38:112 (January 2012), LR 44:1033 (June 2018), LR 45:68 (January 2019), LR 46:1577 (November 2020), LR 50:

### §507. What Documents are Incorporated by Reference Partly or Wholly in this Part? [49 CFR 192.7]

A. Certain material is incorporated by reference into this Subpart with the approval of the Director of the Federal Register under 5 U.S.C. 552(a) and 1 CFR part 51. The materials listed in this Section have the full force of law. All approved material is available for inspection at Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue S.E., Washington, D.C. 20590, 202-366-4046 https://www.phmsa.dot.gov/pipeline/regs, and at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, email fr.inspection@nara.gov or go to www.archives. gov/federal-register/cfr/ibr-locations.html. It is also available from the sources in the following paragraphs of this section. [49 CFR 192.7(a)]

| Source and Name of Referenced Material | Approved for Title 43 Reference |
|---|---|
| B. – C.3. … | |
| 4. ASME/ANSI B31G - 1991 (Reaffirmed 2004), "Manual for Determining the Remaining Strength of Corroded Pipelines," 2004, (ASME/ ANSI B31G). | §§2137.C; 2732.A; 2912.B; 3333.A |
| 5. ASME/ANSI B31.8-2007, "Gas Transmission and Distribution Piping Systems," November 30, 2007, (ASME/ANSI B31.8) | §§912, 2719.A |
| 6. ASME/ANSI B31.8S-2004, "Supplement to B31.8 on Managing System Integrity of Gas Pipelines," approved January 14, 2005, (ASME/ANSI B31.8S) | §§513.D; 2914.C & D; 3303 note to potential impact radius; 3307; 3311.A, A.9 & A.11 thru A.13; 3313.A thru C; 3317.A thru E; 3321.A; 3323.B; 3325.B; 3327.B & C; 3329.B; 3333.C & D; 3335.A &B; 3337.C; 3339.A; 3345.A |
| 7. Reserved | |
| 8. ASME Boiler & Pressure Vessel Code, Section VIII, Division 1 "Rules for Construction of Pressure Vessels," 2007 edition, July 1, 2007, (ASME BPVC, Section VIII, Division 1). | §§1113.A., B & D; 1125.B |
| 9. ASME Boiler & Pressure Vessel Code, Section VIII, Division 2 "Alternate Rules, Rules for Construction of Pressure Vessels," 2007 edition, July 1, 2007, (ASME BPVC, Section VIII, Division 2) | §§1113.B & D; 1125.B |
| 10. ASME Boiler & Pressure Vessel Code, Section IX: "Qualification Standard for Welding and Brazing Procedures, Welders, Brazers, and Welding and Brazing Operators," 2007 edition, July 1, 2007, ASME BPVC, Section IX. | §§1305.A; 1307.A; and 5103 Item II |
| D. – H. … | |
| 1. NACE Standard Practice 0102 - 2010, "In-Line Inspection of Pipelines," Revised 2010 - 03 - 13, (NACE SP0102) | §§1110.A;2145 |

| Source and Name of Referenced Material | Approved for Title 43 Reference |
|---|---|
| 2. NACE SP0204-2008, Standard Practice, "Stress Corrosion Cracking (SCC) Direct Assessment Methodology," reaffirmed September 18, 2008, (NACE SP0204) | §§3323.B;3329.B introductory text, B.1 thru B.3, B.5 introductory text, and B.5.a |
| 3. NACE SP0206-2006, Standard Practice, "Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA)," approved December 1, 2006 | §§3323.B; 3327.B, C introductory text, and C.1 thru C.4 |
| 4. ANSI/NACE SP0502-2010, Standard Practice, "Pipeline External Corrosion Direct Assessment Methodology," revised June 24, 2010, (NACE SP0502) | §§1719.F;2113.H;3323.B; 3325.B;3331.D;3335.B;3339.A |
| I. – K.2. … | |

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 30:1226 (June 2004), amended LR 31:680 (March 2005), LR 33:474 (March 2007), LR 35:2801 (December 2009), LR 38:113 (January 2012), LR 44:1033 (June 2018), LR 45:68 (January 2019), LR 46:1578 (November 2020), LR 47:1141 (August 2021), LR 50:

### §509. What Requirements Apply to Gathering Lines? [49 CFR 192.9]

A. …

B. Offshore Lines. An operator of an offshore gathering line must comply with requirements of this part applicable to transmission lines, except the requirements in §§513.D, 1110, 1515.E, 1719.D - G, 2113.F - I, 2117.D and F, 2125.C, 2130, 2137.C, 2145, 2306, 2707, 2713.C, 2719.E, 2724, 2910, 2912, 2914 and Chapter 33 of this Part. Further, operators of offshore gathering lines are exempt from the requirements of §§2717.B - D and 2735. Lastly, operators of offshore gathering lines are exempt from the requirements of §2715 (but an operator of an offshore gathering line must comply with the requirements LAC 43.XIII.2715, effective as of October 4, 2022). [49 CFR 192.9(b)].

C. Type A Lines. An operator of a Type A regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines, except the requirements in §§513.D, 1110, 1515.E, 1719.D - G, 2113.F - I, 2117.D and F, 2125.C, 2130, 2137.C, 2145, 2306, 2707, 2713.C, 2719.E, 2724, 2910, 2912, 2914 and in Chapter 33 of this Part. However, operators of Type A regulated onshore gathering lines in a Class 2 location may demonstrate compliance with Chapter 31 by describing the processes it uses to determine the qualification of persons performing operations and maintenance tasks. Further, operators of Type A regulated onshore gathering lines are exempt from the requirements of §§1139.E - G, 2710, 2717.B - D, 2734, 2735, 2736, and 2745.C - F. Lastly, operators of Type A regulated onshore gathering lines are exempt from the requirements of §2717.B (but an operator of a Type A regulated onshore gathering line must comply with the requirements of LAC 43.XIII.2717.B effective as of October 4, 2022). [49 CFR 192.9(c)].

D. …

1. if a line is new, replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of this Part applicable to transmission lines except the requirements in §§717, 927, 1139.E and F, 1165, 1307.C, 1515.E, 1719.D - G, 2306, 2734, and 2736. [49 CFR 192.9(d)(1)]

2. if the pipeline is metallic, control corrosion according to requirements of Chapter 21 of this Part applicable to transmission lines except the requirements in §§213.F - I, 2117.D and F, 2125.C, 2132, 2137.C and 2145; [49 CFR 192.9(d)(2)];

3. – E.1. …

a. except as provided in Subsection H of this Section for pipe and components made with composite materials, the design, installation, construction, initial inspection, and initial testing of a new, replaced, relocated, or otherwise changed Type C gathering line, must be done in accordance with the requirements in Chapter 7 - 17 and Chapter 23 of this Part applicable to transmission lines. Compliance with §§717, 927, 1139.E, 1139.F, 1165, 1307.C, 1515.E, 1719.D - G, 2306, 2734, and 2736 is not required; [49 CFR 192.9(e)(1)(i)]

b. if the pipeline is metallic, control corrosion according to requirements of Chapter 21 of this Subpart applicable to transmission lines except for §§2113.F - I, 2117.D and F, 2125.C, 2132, 2137.C, and 2145; [192.9(e)(1)(ii)]

c. …

d. develop and implement procedures for emergency plans in accordance with §2715; effective as of October 4, 2022;

e. – H.3. …

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:220 (April 1983), amended LR 10:511 (July 1984), LR 20:443 (April 1994), LR 21:821 (August 1995), LR 24:1307 (July 1998), LR 30:1227 (June 2004), LR 31:681 (March 2005), LR 33:477 (March 2007), LR 44:1035 (June 2018), LR 46:1579 (November 2020), LR 49:1101 (June 2023), LR 50:

### §513. What General Requirements Apply to Pipelines Regulated Under this Subpart? [49 CFR 192.13]

A. – C. …

D. Each operator of an onshore gas transmission pipeline must evaluate and mitigate, as necessary, significant changes that pose a risk to safety or the environment through a management of change process. Each operator of an onshore gas transmission pipeline must develop and follow a management of change process, as outlined in ASME/ANSI B31.8S, section 11 (incorporated by reference, *see* §507), 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 Chapter 33 of this Part, this management of change process must be implemented by February 26, 2024. The requirements of this Paragraph D do not apply to gas gathering pipelines. Operators may request an extension of up to 1 year by submitting a notification to PHMSA at least 90 days before

February 26, 2024, in accordance with §518. The notification must include a reasonable and technically justified basis, an up-to-date plan for completing all actions required by this section, the reason for the requested extension, current safety or mitigation status of the pipeline segment, the proposed completion date, and any needed temporary safety measures to mitigate the impact on safety. [49 CFR 192.13(d)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:220 (April 1983), amended LR 10:511 (July 1984), LR 30:1227 (June 2004), LR 33:477 (March 2007), LR 50:

### §518. How to Notify PHMSA [49 CFR 192.18]

A. – B. …

C. Unless otherwise specified, if an operator submits, pursuant to §§508, 509, 513,1139, 1719, 2113, 2306, 2707, 2719, 2724, 2732, 2734, 2736, 2910, 2912, 2914, 2945, 3317, 3321, 3327, 3333, or 3337, a notification for use of a different integrity assessment method, analytical method, sampling approach, or technique (*e.g.*, “other technology” or “alternative equivalent technology”) than otherwise prescribed in those sections, that notification must be submitted to PHMSA for review at least 90 days in advance of using the other method, approach, compliance timeline, or technique. An operator may proceed to use the other method, approach, compliance timeline, or technique 91 days after submitting the notification unless it receives a letter from the Associate Administrator for Pipeline Safety informing the operator that PHMSA objects to the proposal, or that PHMSA requires additional time and/or more information to conduct its review. [49 CFR 192.18(c)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 46:1581 (November 2020), LR 50:

## Chapter 11. Design of Pipeline Components [49 CFR Part 192 Subpart D]

### §1139. Transmission Line Valves [49 CFR 192.179]

A. – D. …

E. For onshore transmission pipeline segments with diameters greater than or equal to 6 inches that are constructed after April 10, 2023, the operator must install rupture-mitigation valves (RMV) or an alternative equivalent technology whenever a valve must be installed to meet the appropriate valve spacing requirements of this section. An operator seeking to use alternative equivalent technology must notify PHMSA in accordance with the procedures set forth in Subsection G of this Section. All RMVs and alternative equivalent technologies installed pursuant to this Subsection E must meet the requirements of §2736. The installation requirements in this Subsection E do not apply to pipe segments with a potential impact radius (PIR), as defined in §3303, that is less than or equal to 150 feet in either Class 1 or Class 2 locations. An operator may request an extension of the installation compliance deadline requirements of this Subsection E if it can demonstrate to PHMSA, in accordance with the notification procedures in §518, that those installation compliance deadlines would be economically, technically, or operationally infeasible for a particular new pipeline. [49 CFR 192.179(e)]

F. For entirely replaced onshore transmission pipeline segments, as defined in §503, with diameters greater than or equal to 6 inches and that are installed after April 10, 2023, the operator must install RMVs or an alternative equivalent technology whenever a valve must be installed to meet the appropriate valve spacing requirements of this section. An operator seeking to use alternative equivalent technology must notify PHMSA in accordance with the procedures set forth in Subsection G of this Section. All RMVs and alternative equivalent technologies installed pursuant to this Subsection must meet the requirements of §2736. The requirements of this Subsection apply when the applicable pipeline replacement project involves a valve, either through addition, replacement, or removal. The installation requirements of this Subsection do not apply to pipe segments with a PIR, as defined in §3303 that is less than or equal to 150 feet in either Class 1 or Class 2 locations. An operator may request an extension of the installation compliance deadline requirements of this Subsection if it can demonstrate to PHMSA, in accordance with the notification procedures in §518, that those installation compliance deadlines would be economically, technically, or operationally infeasible for a particular pipeline replacement project. [49 CFR 192.179(f)]

G. – H.3.…

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:225 (April 1983), amended LR 10:518 (July 1984), LR 24:1308 (July 1998), LR 27:1540 (September 2001), LR 30:1237 (June 2004), LR 49:1104 (June 2023), LR 50:

## Chapter 15. Joining of Materials Other Than by Welding [49 CFR Part 192 Subpart F]

### §1513. Plastic Pipe: Qualifying Joining Procedures [49 CFR 192.283]

A. – C. …

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:231 (April 1983), amended LR 10:523 (July 1984), LR 20:445 (April 1994), LR 24:1310 (July 1998), LR 27:1541 (September 2001), LR 30:1244 (June 2004), LR 31:683 (March 2005), LR 33:479 (March 2007), LR 38:116 (January 2012), LR 44:1039 (June 2018), LR 46:1585 (November 2020), LR. 47:1144 (August 2021), LR 50:

## Chapter 17. General Construction Requirements for Transmission Lines and Mains [49 CFR Part 192 Subpart G]

### §1705. Inspection: General [49 CFR 192.305]

A. …

B. Each operator shall notify the Pipeline Safety Section of the Office of Conservation, Louisiana Department of Energy and Natural Resources by submitting the Notice of

Construction form by electronic mail at PipelineInspectors@la.gov of any new proposed pipeline construction or replacement for a total length of 1 mile or more on transmission lines or mains at least 7 days prior to commencement of said construction.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:232 (April 1983), amended LR 10:524 (July 1984), LR 20:446 (April 1994), LR 21:821 (August 1995), LR 30:1245 (June 2004), LR 44:1039 (June 2018), LR 50:

### §1719. Installation of Pipe in a Ditch [49 CFR 192.319]

A. – C. …

D. Promptly after a ditch for an onshore steel transmission line is backfilled (if the construction project involves 1,000 feet or more of continuous backfill length along the pipeline), but not later than 6 months after placing the pipeline in service, the operator must perform an assessment to assess any coating damage and ensure integrity of the coating using direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or other technology that provides comparable information about the integrity of the coating. Coating surveys must be conducted, except in locations where effective coating surveys are precluded by geographical, technical, or safety reasons. [49 CFR 192.319(d)]

E. An operator must notify PHMSA in accordance with § 518 at least 90 days in advance of using other technology to assess integrity of the coating under Subsection D of this Section. [49 CFR 192.319(e)]

F. An operator of an onshore steel transmission pipeline must develop a remedial action plan and apply for any necessary permits within 6 months of completing the assessment that identified the deficiency. An operator must repair any coating damage classified as severe (voltage drop greater than 60 percent for DCVG or 70 dBμV for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, *see* §507) within 6 months of the assessment, or as soon as practicable after obtaining necessary permits, not to exceed 6 months after the receipt of permits. [49 CFR 192.319(f)]

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 Subsections D - F of this Section. [49 CFR 192.319(f)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:233 (April 1983), amended LR 10:525 (July 1984), LR 20:446 (April 1994), LR 24:1310 (July 1998), LR 27:1542 (September 2001), LR 30:1246 (June 2004).

# Chapter 21. Requirements for Corrosion Control [49 CFR Part 192 Subpart I]

### §2113. External Corrosion Control: Protective Coating [49 CFR 192.461]

A. – A.3. …

4. have sufficient strength to resist damage due to handling(including, but not limited to, transportation, installation, boring, and backfilling) and soil stress; and [49 CFR 192.461(a)(4)]

A.5. – E. …

F. Promptly after the backfill of an onshore steel transmission pipeline ditch following repair or replacement (if the repair or replacement results in 1,000 feet or more of backfill length along the pipeline), but no later than 6 months after the backfill, the operator must perform an assessment to assess any coating damage and ensure integrity of the coating using direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or other technology that provides comparable information about the integrity of the coating. Coating surveys must be conducted, except in locations where effective coating surveys are precluded by geographical, technical, or safety reasons. [49 CFR 192.461(f)]

G. An operator must notify PHMSA in accordance with §518 at least 90 days in advance of using other technology to assess integrity of the coating under Subsection F of this Section. [49 CFR 192.461(g)]

H. An operator of an onshore steel transmission pipeline must develop a remedial action plan and apply for any necessary permits within 6 months of completing the assessment that identified the deficiency. The operator must repair any coating damage classified as severe (voltage drop greater than 60 percent for DCVG or 70 dBμV for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, *see* §507) within 6 months of the assessment, or as soon as practicable after obtaining necessary permits, not to exceed 6 months after the receipt of permits. [49 CFR 192.461(h)]

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 Subsections F - H of this Section. [49 CFR 192.461(i)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:236 (April 1983), amended LR 10:528 (July 1984), LR 30:1253 (June 2004), LR 50:

### §2117. External Corrosion Control: Monitoring [49 CFR 192.465]

A. – C. …

D. Each operator must promptly correct any deficiencies indicated by the inspection and testing required by Subsections A - C of this Section. Remedial action must be completed promptly, but no later than the earliest of the following: prior to the next inspection or test internal or within 90 days from the date the deficiency was discovered. The Commissioner may approve an alternative time period depending on the nature of the deficiency.[49 CFR 192.465(d)]

E. …

F. An operator must determine the extent of the area with inadequate cathodic protection for onshore gas transmission pipelines where any annual test station reading (pipe-to-soil potential measurement) indicates cathodic protection levels below the required levels in appendix D to this Part. [49 CFR 192.465(f)]

1. Gas transmission pipeline operators must investigate and mitigate any non-systemic or location-specific causes. Remedial action must be in accordance with Subsection D of this Section. [49 CFR 192.465(f)(1)]

2. To address systemic causes, an operator must conduct close interval surveys in both directions from the test station with a low cathodic protection reading at a maximum interval of approximately 5 feet or less. An operator must conduct close interval surveys unless it is impractical based upon geographical, technical, or safety reasons. An operator must complete close interval surveys required by this section with the protective current interrupted unless it is impractical to do so for technical or safety reasons. An operator must remediate areas with insufficient cathodic protection levels, or areas where protective current is found to be leaving the pipeline. For onshore gas transmission pipelines, each operator must develop a remedial action plan and apply for any necessary permits within 6 months of completing the inspection or testing that identified the deficiency. Remedial action must be completed promptly, but no later than the earliest of the following: prior to the next inspection or test interval required by this section; within 1 year, not to exceed 15 months, of the inspection or test that identified the deficiency; or as soon as practicable, not to exceed 6 months, after obtaining any necessary permits. An operator must confirm the restoration of adequate cathodic protection following the implementation of remedial actions undertaken to mitigate systemic causes of external corrosion. [49 CFR 192.465(f)(2)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:236 (April 1983), amended LR 10:528 (July 1984), LR 27:1545 (September 2001), LR 30:1253 (June 2004), LR 38:116 (January 2012), LR 47:1144 (August 2021), LR 50:

### §2125. External Corrosion Control: Interference Currents [49 CFR 192.473]

A. – B. …

C. For onshore gas transmission pipelines, the program required by Subsection A of this Section must include: [49 CFR 192.473(c)]

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; [49 CFR 192.473(c)(1)]

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; [49 CFR 192.473(c)(2)]

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 [49 CFR 192.473(c)(3)]

4. application for any necessary permits within 6 months of completing the interference survey that identified the deficiency. An operator must complete remedial actions promptly, but no later than the earliest of the following: within 15 months after completing the interference survey that identified the deficiency; or as soon as practicable, but not to exceed 6 months, after obtaining any necessary permits. [49 CFR 192.473(c)(4)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:236 (April 1983), amended LR 10:529 (July 1984), LR 30:1254 (June 2004), LR 50:

### §2130. Internal corrosion control: Onshore transmission monitoring and mitigation. [49 CFR 192.478]

A. Each operator of an onshore gas transmission pipeline with corrosive constituents in the gas being transported must develop and implement a monitoring and mitigation program to mitigate the corrosive effects, as necessary. Potentially corrosive constituents include, but are not limited to: carbon dioxide, hydrogen sulfide, sulfur, microbes, and liquid water, either by itself or in combination. An operator must evaluate the partial pressure of each corrosive constituent, where applicable, by itself or in combination, to evaluate the effect of the corrosive constituents on the internal corrosion of the pipe and implement mitigation measures as necessary. [49 CFR 192.478(a)]

B. The monitoring and mitigation program described in Subsection A of this Section must include: [49 CFR 192.478(b)]

1. the use of gas-quality monitoring methods at points where gas with potentially corrosive contaminants enters the pipeline to determine the gas stream constituents. [49 CFR 192.478(b)(1)]

2. technology to mitigate the potentially corrosive gas stream constituents. Such technologies may include product sampling, inhibitor injections, in-line cleaning pigging, separators, or other technology that mitigates potentially corrosive effects. [49 CFR 192.478(b)(2)]

3. an evaluation at least once each calendar year, at intervals not to exceed 15 months, to ensure that potentially corrosive gas stream constituents are effectively monitored and mitigated. [49 CFR 192.478(b)(3)]

C. An operator must review its monitoring and mitigation program at least once each calendar year, at intervals not to exceed 15 months, and based on the results of its monitoring and mitigation program, implement adjustments, as necessary. [49 CFR 192.478(c)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 50:

### §2137. Remedial Measures: Transmission Lines [49 CFR 192.485]

A. – B. …

C. Under Subsections A and B of this Section, the strength of pipe based on actual remaining wall thickness must be determined and documented in accordance with §2912. [49 CFR 192.485(c)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:237 (April 1983), amended LR 10:529 (July 1984), LR 24:1311 (July 1998), LR 27:1545 (September 2001), LR 30:1255 (June 2004), LR 44:1041 (June 2018), LR 50:

### §2710. Change in class location: Change in valve spacing. [49 CFR 192.610]

A. …

B. If a class location change occurs on a gas transmission pipeline after October 5, 2022 and results in pipe replacement of less than 2 miles within 5 contiguous miles during a 24-month period, to meet the MAOP requirements in §§2711, 2719, or 2720, then within 24 months of the class location change, in accordance with §2711.D, the operator must either: [49 CFR 192.610(b)]

1. – C. …

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICALNOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 49:1105 (June 2023), LR 50:

# Chapter 27. Operations [49 CFR Part 192 Subpart L]

### §2713. Continuing Surveillance [49 CFR 192.613]

A. – B. …

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. [49 CFR 192.613(c)]

1. An operator must assess the nature of the event and the physical characteristics, operating conditions, location, and prior history of the affected pipeline in determining the appropriate method for performing the initial inspection to determine the extent of any damage and the need for the additional assessments required under this Paragraph C.1. [49 CFR 192.613(c)(1)]

2. An operator must commence the inspection required by Subsection C of this Section within 72 hours after the point in time when the operator reasonably determines that the affected area can be safely accessed by personnel and equipment, and the personnel and equipment required to perform the inspection as determined by Paragraph C.1 of this Section are available. If an operator is unable to commence the inspection due to the unavailability of personnel or equipment, the operator must notify the Pipeline Division Director at pipelineinspectors@la.gov as soon as practicable. [49 CFR 192.613(c)(2)]

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 Subsection C of this Section. Such actions might include, but are not limited to: [49 CFR 192.613(c)(3)]

a. reducing the operating pressure or shutting down the pipeline; [49 CFR 192.613(c)(3)(i)]

b. modifying, repairing, or replacing any damaged pipeline facilities; [49 CFR 192.613(c)(3)(ii)]

c. preventing, mitigating, or eliminating any unsafe conditions in the pipeline right-of-way; [49 CFR 192.613(c)(3)(iii)]

d. performing additional patrols, surveys, tests, or inspections; [49 CFR 192.613(c)(3)(iv)]

e. implementing emergency response activities with Federal, State, or local personnel; or [49 CFR 192.613(c)(3)(v)]

f. notifying affected communities of the steps that can be taken to ensure public safety. [49 CFR 192.613(c)(3)(vi)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:241 (April 1983), amended LR 10:533 (July 1984), LR 30:1262 (June 2004), LR 50:

### §2734. Transmission Lines: Onshore Valve Shut-Off For Rupture Mitigation [49 CFR 192.634]

A. – B.2.c. …

3. Laterals. Laterals extending from shut-off segments that contribute less than 5 percent of the total shut-off segment volume may have RMVs or alternative equivalent technologies that meet the actuation requirements of this section at locations other than mainline receipt/delivery points, as long as all of the laterals contributing gas volumes to the shut-off segment do not contribute more than 5 percent of the total shut-off segment gas volume based upon maximum flow volume at the operating pressure. For laterals that are 12 inches in diameter or less, a check valve that allows gas to flow freely in one direction and contains a mechanism to automatically prevent flow in the other direction may be used as an alternative equivalent technology where it is positioned to stop flow into the shut-off segment. Such check valves that are used as an alternative equivalent technology in accordance with this Subsection are not subject to §2736, but they must be inspected, operated, and remediated in accordance with §2945, including for closure and leakage to ensure operational reliability. An operator using such a check valve as an alternative equivalent technology must notify PHMSA in accordance with §§518 and 1139 develop and implement maintenance procedures for such equipment that meet §2945. [49 CFR 192.634(b)(3)]

B.4. …

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 49:1107 (June 2023), LR 50:

### §2736. Transmission Lines: Response to a Rupture; Capabilities of Rupture-Mitigation Valves (RMVS) or Alternative Equivalent Technologies [49 CFR 192.636]

A. – G. …

H. Manual operation upon identification of a rupture. Operators using a manual valve as an alternative equivalent technology as authorized pursuant to §§518, 1139, and 2734 and this Section must develop and implement operating procedures that appropriately designate and locate nearby personnel to ensure valve shutoff in accordance with this section and §2734. Manual operation of valves must include time for the assembly of necessary operating personnel, the acquisition of necessary tools and equipment, driving time under heavy traffic conditions and at the posted speed limit, walking time to access the valve, and time to shut off all valves manually, not to exceed the maximum response time allowed under Subsections B or C of this Section. [49 CFR 192.636(h)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 49:1108 (June 2023), LR 50:

# Chapter 29. Maintenance [49 CFR Part 192 Subpart M]

### §2910. Transmission Lines: Assessments Outside of High Consequence Areas [49 CFR 192.710]

A. – E. …

F. Remediation. An operator must comply with the requirements in §§2137, 2911, 2912, 2913 and 2914, where applicable, if a condition that could adversely affect the safe operation of a pipeline is discovered. [49 CFR 192.710(f)]

G. …

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 46:1594 (November 2020), LR 50:

### §2911. Transmission Lines: General Requirements for Repair Procedures [49 CFR 192.711]

A. – B. …

1. Non Integrity Management Repairs: [49 CFR 192.711(b)(1)]

a. gathering lines and offshore transmission lines: For gathering lines subject to this section in accordance with §509 and for offshore transmission lines, an operator must make permanent repairs as soon as feasible. [49 CFR 192.711(b)(1)(i)]

b. onshore transmission lines: Except for gathering lines exempted from this Section in accordance with §509 and offshore transmission lines, after May 24, 2023, whenever an operator discovers any condition that could adversely affect the safe operation of a pipeline segment not covered by an integrity management program under subpart O of this part, it must correct the condition as prescribed in §2914. [49 CFR 192.711(b)(1)(ii)]

2. – C. …

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:245 (April 1983), amended LR 10:537 (July 1984), LR 27:1548 (September 2001), LR 30:1268 (June 2004), LR 38:120 (January 2012), LR 50:

### §2912. Analysis of Predicted Failure Pressure and Critical Strain Level. [49 CFR 192.712]

A. – B. …

1. If an operator would choose to use a remaining strength calculation method that could provide a less conservative result than the methods listed in paragraph (b) introductory text, the operator must notify PHMSA in advance in accordance with §518.C. [49 CFR 192.712(b)(1)]

2. The notification provided for by paragraph (b)(1) of this section must include a comparison of its predicted failure pressures to R-STRENG or ASME/ANSI B31G, all burst pressure tests used, and any other technical reviews used to qualify the calculation method(s) for varying corrosion profiles. [49 CFR 192.712(b)(2)]

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: [49 CFR 192.712(c)]

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. [49 CFR 192.712(c)(1)]

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. [49 CFR 192.712(c)(2)]

3. perform pipeline curvature-based strain analysis using recent HR-Deformation inspection data. [49 CFR 192.712(c)(3)]

4. compare the dent profile between the most recent and previous in-line inspections to identify significant changes in dent depth and shape.[49 CFR 192.712(c)(4)]

5. identify and quantify all previous and present significant loads acting on the dent. [49 CFR 192.712(c)(5)]

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. [49 CFR 192.712(c)(6)]

7. the analyses performed in accordance with this section must account for material property uncertainties, model inaccuracies, and inline inspection tool sizing tolerances. [49 CFR 192.712(c)(7)]

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 §2913, §2914, or §3333, as applicable. [49 CFR 192.712(c)(8)]

9. using operational pressure data, a valid fatigue life prediction model that is appropriate for the pipeline segment, and assuming a reassessment safety factor of 5 or greater for the assessment interval, estimate the fatigue life of the dent by Finite Element Analysis or other analytical technique that is technically appropriate for dent assessment and reassessment intervals in accordance with this section. Multiple dent or other fatigue models must be used for the evaluation as a part of the engineering critical assessment. [49 CFR 192.712(c)(9)]

10. 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. [49 CFR 192.712(c)(10)]

11. an operator using an engineering critical assessment procedure, other technologies, or techniques to comply with Subsection C of this Section must submit advance notification to PHMSA, with the relevant procedures, in accordance with §518. [49 CFR 192.712(c)(11)]

D. – G.19. …

H. Reassessments. If an operator uses an engineering critical assessment method in accordance with Subsections C and D of this Section to determine the maximum reevaluation intervals, the operator must reassess the anomalies as follows: [49 CFR 192.712(h)]

1. if the anomaly is in an HCA, the operator must reassess the anomaly within a maximum of 7 years in accordance with §3339.A, unless the safety factor is expected to go below what is specified in Subsection C or D) of this Section. [49 CFR 192.712(h)(1)]

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 §2910.B, unless the anomaly safety factor is expected to go below what is specified in Subsection C or D of this Section. [49 CFR 192.712(h)(2)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 46:1595 (November 2020), LR 47:1146 (August 2021), LR 50:

### §2914. Transmission lines: Repair criteria for onshore transmission pipelines. [49 CFR 192.714]

A. Applicability. This section applies to onshore transmission pipelines not subject to the repair criteria in subpart O of this part, and which do not operate under an alternative MAOP in accordance with §§912, 1728, and 2720. Pipeline segments that are located in high consequence areas, as defined in §3303, must comply with the applicable actions specified by the integrity management requirements in Chapter 33. Pipeline segments operating under an alternative MAOP in accordance with §§912, 1728, and 2720 must comply with §2720.D.k. [49 CFR 192.714(a)]

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 §2912 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 §2707. Until documented material properties are available, the operator must use the conservative assumptions in either §2912.E.2 or, if appropriate following a pressure test, in §2912.D.3. [49 CFR 192.714(b)]

C. Schedule for evaluation and remediation. An operator must remediate conditions according to a schedule that prioritizes the conditions for evaluation and remediation. Unless Subsection D of this Section provides a special requirement for remediating certain conditions, an operator must calculate the predicted failure pressure of anomalies or defects and follow the schedule in ASME/ANSI B31.8S (incorporated by reference, *see* §507), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must document the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety. Each condition that meets any of the repair criteria in Subsection D of this Section in an onshore steel transmission pipeline must be— [49 CFR 192.714(c)]

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 §905 and the design factors for the class location in which it is located; or [49 CFR 192.714(c)(1)]

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. [49 CFR 192.714(c)(2)]

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: [49 CFR 192.714(d)]

1. immediate repair conditions. An operator's evaluation and remediation schedule for immediate repair conditions must follow section 7 of ASME/ANSI B31.8S (incorporated by reference, *see* §507). An operator must repair the following conditions immediately upon discovery: [49 CFR 192.714(d)(1)]

a. 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 §2912.B, of less than or equal to 1.1 times the MAOP. [49 CFR 192.714(d)(1)(i)]

b. 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 §2912.C demonstrates critical strain levels are not exceeded. [49 CFR 192.714(d)(1)(ii)]

c. metal loss greater than 80 percent of nominal wall regardless of dimensions. [49 CFR 192.714(d)(1)(iii)]

d. metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or has a longitudinal joint factor less than 1.0, and the predicted failure pressure determined in accordance with §2912.D is less than 1.25 times the MAOP. [49 CFR 192.714(d)(1)(iv)]

e. a crack or crack-like anomaly meeting any of the following criteria: [49 CFR 192.714(d)(1)(v)]

i. crack depth plus any metal loss is greater than 50 percent of pipe wall thickness; [49 CFR 192.714(d)(1)(v)(A)]

ii. crack depth plus any metal loss is greater than the inspection tool's maximum measurable depth; or [49 CFR 192.712(d)(1)(v)(B)]

iii. the crack or crack-like anomaly has a predicted failure pressure, determined in accordance with §2912.D, that is less than 1.25 times the MAOP. [49 CFR 192.712(d)(1)(v)(C)]

f. an indication or anomaly that, in the judgment of the person designated by the operator to evaluate the assessment results, requires immediate action. [49 CFR 192.714(d)(1)(vi)]

2. two-year conditions. An operator must repair the following conditions within 2 years of discovery: [49 CFR 192.714(d)(2)]

a. 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 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless an engineering analysis performed in accordance with §2912.C demonstrates critical strain levels are not exceeded. [49 CFR 192.714(d)(2)(i)]

b. a dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal or helical (spiral) seam weld, unless an engineering analysis performed in accordance with §2912.C demonstrates critical strain levels are not exceeded. [49 CFR 192.714(d)(2)(ii)]

c. 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 §2912.C demonstrates critical strain levels are not exceeded. [49 CFR 192.714(d)(2)(iii)]

d. for metal loss anomalies, a calculation of the remaining strength of the pipe shows a predicted failure pressure, determined in accordance with §2912.B at the location of the anomaly, of less than 1.39 times the MAOP for Class 2 locations, or less than 1.50 times the MAOP for Class 3 and 4 locations. For metal loss anomalies in Class 1 locations with a predicted failure pressure greater than 1.1 times MAOP, an operator must follow the remediation schedule specified in ASME/ANSI B31.8S (incorporated by reference, *see* §507), section 7, Figure 4, as specified in Subsection C of this Section. [49 CFR 192.714(d)(2)(iv)]

e. 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 §2912.B, less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with §2711 or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations. [49 CFR 192.714(d)(2)(v)]

f. metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or has a longitudinal joint factor less than 1.0, and the predicted failure pressure determined in accordance with §2912.D is less than 1.25 times the MAOP. [49 CFR 192.714(d)(2)(vi)]

g. a crack or crack-like anomaly that has a predicted failure pressure, determined in accordance with §2912.D, that is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with §2711, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations. [49 CFR 192.714(d)(2)(vii)]

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: [49 CFR 192.714(d)(3)]

a. a dent that is located between the 4 o'clock and 8 o'clock positions (bottom 1/3 of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), and where an engineering analysis, performed in accordance with §2912.C, demonstrates critical strain levels are not exceeded. [49 CFR 192.714(d)(3)(i)]

b. a dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), and where an engineering analysis performed in accordance with §2912.C determines that critical strain levels are not exceeded. [49 CFR 192.714(d)(3)(ii)]

c. a dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or longitudinal or helical (spiral) seam weld, and where an engineering analysis of the dent and girth or seam weld, performed in accordance with §2912.C, demonstrates critical strain levels are not exceeded. These analyses must consider weld mechanical properties. [49 CFR 192.714(d)(3)(iii)]

d. a dent that has metal loss, cracking, or a stress riser, and where an engineering analysis performed in accordance with §2912.C demonstrates critical strain levels are not exceeded. [49 CFR 192.714(d)(3)(iv)]

e. 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 §2912.D, is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with §2711, 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. [49 CFR 192.714(d)(3)(v)]

f. a crack or crack-like anomaly for which the predicted failure pressure, determined in accordance with §2912.D, is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with §2711, 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. [49 CFR 192.714(d)(3)(vi]

E. Temporary pressure reduction. [49 CFR 192.714(e)]

1. Immediately upon discovery and until an operator remediates the condition specified in Paragraph D.1 of this Section, or upon a determination by an operator that it is unable to respond within the time limits for the conditions specified in Paragraph D.2 of this Section, the operator must reduce the operating pressure of the affected pipeline to any one of the following based on safety considerations for the public and operating personnel: [49 CFR 192.714(e)(1)]

a. a level not exceeding 80 percent of the operating pressure at the time the condition was discovered; [49 CFR 192.714(e)(1)(i)]

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 [49 CFR 192.714(e)(1)(ii)]

c. a level not exceeding the predicted failure pressure divided by 1.1. [49 CFR 192.714(e)(1)(iii)]

2. An operator must notify PHMSA in accordance with §518 if it cannot meet the schedule for evaluation and remediation required under Subsection C or D of this Section and cannot provide safety through a temporary reduction in operating pressure or other action. Notification to PHMSA does not alleviate an operator from the evaluation, remediation, or pressure reduction requirements in this section. [49 CFR 192.714(e)(1)]

3. When a pressure reduction, in accordance with Subsection E of this Section, exceeds 365 days, an operator must notify PHMSA in accordance with §518 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. [49 CFR 192.714(e)(3)]

4. An operator must document and keep records of the calculations and decisions used to determine the reduced operating pressure and the implementation of the actual reduced operating pressure for a period of 5 years after the pipeline has been repaired. [49 CFR 192.714(e)(4)]

F. Other conditions. Unless another timeframe is specified in Subsection 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. [49 CFR 192.714(f)]

G. In situ direct examination of crack defects. Whenever an operator finds conditions that require the pipeline to be repaired, in accordance with this section, an operator must perform a direct examination of known locations of cracks or crack-like defects using technology that has been validated to detect tight cracks (equal to or less than 0.008 inches crack opening), such as inverse wave field extrapolation (IWEX), phased array ultrasonic testing (PAUT), ultrasonic testing (UT), or equivalent technology. “In situ” examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards, including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection for accuracy of the type of defects and pipe material being evaluated. The procedures must account for inaccuracies in evaluations and fracture mechanics models for failure pressure determinations. [49 CFR 192.714(g)]

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 §2912.[49 CFR 192.714(h)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division

# Chapter 33. Gas Transmission Pipeline Integrity Management [49 CFR Part 192 Subpart O]

### §3311. What are the Elements of an Integrity Management Program? [49 CFR 192.911]

A. – 10. …

11. a management of change process as required by §513.D; [49 CFR 192.911(k)]

12. – 16. …

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 30:1275 (June 2004), amended LR 31:686 (March 2005), LR 46:1598 (November 2020), LR 50:

### §3317. How Does an Operator Identify Potential Threats to Pipeline Integrity and Use the Threat Identification in Its Integrity Program? [49 CFR 192.917]

A. Threat Identification. An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (incorporated by reference, see §507), Section 2, which are grouped under the following four threat categories [49 CFR 192.917(a)]:

1. …

2. stable threats, such as manufacturing, welding, fabrication, or construction defects; [49 CFR 192.917(a)(2)]

3. …

4. human error, such as operational or maintenance mishaps, or design and construction mistakes. [49 CFR 192.917(a)(4)]

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. Operators must begin to integrate all pertinent data elements specified in this section starting on May 24, 2023, with all available attributes integrated by February 26, 2024. An operator may request an extension of up to 1 year by submitting a notification to PHMSA at least 90 days before February 26, 2024, in accordance with §518. The notification must include a reasonable and technically justified basis, an up-to-date plan for completing all actions required by this Subsection B, the reason for the requested extension, current safety or mitigation status of the pipeline segment, the proposed completion date, and any needed temporary safety measures to mitigate the impact on safety. An operator must gather and evaluate the set of data listed in Paragraph B.1 of this Section. The evaluation must analyze both the covered segment and similar non-covered segments, and it must: [49 CFR 192.917(b)].

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: [49 CFR 192.917(b)(1)]

a. pipe diameter, wall thickness, seam type, and joint factor; [49 CFR 192.917(b)(1)(i)]

b. manufacturer and manufacturing date, including manufacturing data and records;[49 CFR 192.917(b)(1)(ii)]

c. material properties including, but not limited to, grade, specified minimum yield strength (SMYS), and ultimate tensile strength; [49 CFR 192.917(b)(1)(iii)]

d. equipment properties; [49 CFR 192.917(b)(1)(iv)]

e. year of installation; [49 CFR 192.917(b)(1)(v)]

f. bending method; [49 CFR 192.917(b)(1)(vi)]

g. joining method, including process and inspection results; [49 CFR 192.917(b)(1)(vii)]

h. depth of cover; [49 CFR 192.917(b)(1)(viii)]

i. crossings, casings (including if shorted), and locations of foreign line crossings and nearby high voltage power lines; [49 CFR 192.917(b)(1)(ix)]

j. hydrostatic or other pressure test history, including test pressures and test leaks or failures, failure causes, and repairs; [49 CFR 192.917(b)(1)(x)]

k. pipe coating methods (both manufactured and field applied), including the method or process used to apply girth weld coating, inspection reports, and coating repairs; [49 CFR 192.917(b)(1)(xi)]

l. soil, backfill; [49 CFR 192.917(b)(1)(xii)]

m. construction inspection reports, including but not limited to: [49 CFR 192.917(b)(1)(xiii)]

i. post backfill coating surveys; and [49 CFR 192.917(b)(1)(xiii)(A)]

ii. coating inspection ("jeeping" or "holiday inspection") reports; [49 CFR 192.917(b)(1)(xiii)(B)]

n. cathodic protection installed, including, but not limited to, type and location; [49 CFR 192.917(b)(1)(xiv)]

o. coating type; [49 CFR 192.917(b)(1)(xv)]

p. gas quality; [49 CFR 192.917(b)(1)(xvi)]

q. flow rate; [49 CFR 192.917(b)(1)(xvii)]

r. normal maximum and minimum operating pressures, including maximum allowable operating pressure (MAOP); [49 CFR 192.917(b)(1)(xviii)]

s. class location; [49 CFR 192.917(b)(1)(xix)]

t. 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 §2717, and their identified causes and consequences; [49 CFR 192.917(b)(1)(xx)]

u. coating condition; [49 CFR 192.917(b)(1)(xxi)]

v. cathodic protection (CP) system performance; [49 CFR 192.917(b)(1)(xxii)]

v. pipe wall temperature; [49 CFR 192.917(b)(1)(xxiii)]

w. pipe operational and maintenance inspection reports, including, but not limited to: [49 CFR 192.917(b)(1)(xxiv)]

i. 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; [49 CFR 192.917(b)(1)(xxiv)(A)]

ii. close interval survey (CIS) and electrical survey results; [49 CFR 192.917(b)(1)(xxiv)(B)]

iii. CP rectifier readings; [49 CFR 192.917(b)(1)(xxiv)(C)]

iv. CP test point survey readings and locations; [49 CFR 192.917(b)(1)(xxiv)(D)]

v. alternating current, direct current, and foreign structure interference surveys; [49 CFR 192.917(b)(1)(xxiv)(E)]

vi. 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; [49 CFR 192.917(b)(1)(xxiv)(F)]

vii. results of examinations of exposed portions of buried pipelines ( *e.g.,* pipe and pipe coating condition, *see* §2111), including the results of any non-destructive examinations of the pipe, seam, or girth weld ( *i.e.* bell hole inspections); [49 CFR 192.917(b)(1)(xxiv)(G)]

viii. stress corrosion cracking excavations and findings; [49 CFR 192.917(b)(1)(xxiv)(H)]

ix. selective seam weld corrosion excavations and findings; [49 CFR 192.917(b)(1)(xxiv)(I)]

x. any indication of seam cracking; and49 CFR 192.917(b)(1)(xxiv)(J)]

xi. gas stream sampling and internal corrosion monitoring results, including cleaning pig sampling results; [49 CFR 192.917(b)(1)(xxiv)(K)]

x. external and internal corrosion monitoring; [49 CFR 192.917(b)(1)(xxv)]

y. operating pressure history and pressure fluctuations, including an analysis of effects of pressure cycling and instances of exceeding MAOP by any amount; [49 CFR 192.917(b)(1)(xxvi)]

z. performance of regulators, relief valves, pressure control devices, or any other device to control or limit operating pressure to less than MAOP; [49 CFR 192.917(b)(1)(xxvii)]

aa. encroachments; [49 CFR 192.917(b)(1)(xxviii)]

bb. repairs; [49 CFR 192.917(b)(1)(xxix)]

cc. vandalism; [49 CFR 192.917(b)(1)(xxx)]

dd. external forces; [49 CFR 192.917(b)(1)(xxxi)]

ee. audits and reviews; [49 CFR 192.917(b)(1)(xxxii)]

ff. industry experience for incident, leak, and failure history; [49 CFR 192.917(b)(1)(xxxiii)]

gg. aerial photography; and [49 CFR 192.917(b)(1)(xxxiv)]

hh. exposure to natural forces in the area of the pipeline, including seismicity, geology, and soil stability of the area. [49 CFR 192.917(b)(1)(xxxv)]

2. Use validated information and data as inputs, to the maximum extent practicable. If input is obtained from subject matter experts (SME), an operator must employ adequate control measures to ensure consistency and accuracy of information. Control measures may include training of SMEs or the use of outside technical experts (independent expert reviews) to assess the quality of processes and the judgment of SMEs. An operator must document the names and qualifications of the individuals who approve SME inputs used in the current risk assessment. [49 CFR 192.917(b)(2)]

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). [49 CFR 192.917(b)(3)]

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. [49 CFR 192.917(b)(4)]

C. Risk Assessment. An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, Section 5, and that analyzes the identified threats and potential consequences of an incident for each covered segment. An operator must ensure the validity of the methods used to conduct the risk assessment considering the incident, leak, and failure history of the pipeline segments and other historical information. Such a validation must ensure the risk assessment methods produce a risk characterization that is consistent with the operator's and industry experience, including evaluations of the cause of past incidents, as determined by root cause analysis or other equivalent means, and include sensitivity analysis of the factors used to characterize both the likelihood of loss of pipeline integrity and consequences of the postulated loss of pipeline integrity. An operator must use the risk assessment to determine additional preventive and mitigative measures needed for each covered segment in accordance with §3335 and periodically evaluate the integrity of each covered pipeline segment in accordance with §3337. Beginning February 26, 2024, the risk assessment must: [49 CFR 192.917(c)]

1. analyze how a potential failure could affect high consequence areas; [49 CFR 192.917(c)(1)]

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; [49 CFR 192.917(c)(2)]

3. account for, and compensate for, uncertainties in the model and the data used in the risk assessment; and [49 CFR 192.917(c)(3)]

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. [49 CFR 192.917(c)(4)]

5. in conjunction with §3317.B, an operator may request an extension of up to 1 year for the requirements of this paragraph by submitting a notification to PHMSA at least 90 days before February 26, 2024, in accordance with §518. The notification must include a reasonable and technically justified basis, an up-to-date plan for completing all actions required by this Paragraph C.5, the reason for the requested extension, current safety or mitigation status of the pipeline segment, the proposed completion date, and any needed temporary safety measures to mitigate the impact on safety. [49 CFR 192.917(c)(5)]

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. [49 CFR 192.917(d)]

E. – 6. …

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 30:1276 (June 2004), amended LR 31:686 (March 2005), LR 33:483 (March 2007), LR 46:1598 (November 2020), LR 50:

### §3323. How Is Direct Assessment Used and for What Threats? [49 CFR 192.923]

A. – B.1. …

2. §3327 and NACE SP0206 (incorporated by reference, see §507), if addressing internal corrosion (IC). [49 CFR 192.923(b)(2)]

3. §3329 and NACE SP0204 (incorporated by reference, see §507), if addressing stress corrosion cracking (SCC). [49 CFR 192.923(b)(3)]

C. …

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 30:1278 (June 2004), amended LR 38:121 (January 2012), LR 44:1043 (June 2018), LR 46:1599 (November 2020).

### §3327. What Are the Requirements for Using Internal Corrosion Direct Assessment (ICDA)? [49 CFR 192.927]

A. …

B. General Requirements. An operator using direct assessment as an assessment method to address internal corrosion in a covered pipeline segment must follow the requirements in this Section and in NACE SP0206 (incorporated by reference, see §507). The Dry Gas Internal Corrosion Direct Assessment (DG-ICDA) process described in this Section applies only for a segment of pipe transporting nominally dry natural gas (see § 507), and not for a segment with electrolyte nominally present in the gas stream. If an operator uses ICDA to assess a covered segment operating with electrolyte present in the gas stream, the operator must develop a plan that demonstrates how it will conduct ICDA in the segment to address effectively internal corrosion, and must notify PHMSA in accordance with §518. In the event of a conflict between this section and NACE SP0206, the requirements in this section control. [49 CFR 192.927(b).]

C. The ICDA Plan. An operator must develop and follow an ICDA plan that meets NACE SP0206 (incorporated by reference, *see* §507) 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. [49 CFR 192.927(c)]

1. Preassessment. An operator must comply with NACE SP0206 (incorporated by reference, *see* §507) in conducting the preassessment step of the ICDA process. [49 CFR 192.927(c)(1)]

2. Indirect inspection. An operator must comply with NACE SP0206 (incorporated by reference, *see* §507), and the following additional requirements, in conducting the

Indirect Inspection step of the ICDA process. An operator must explicitly document the results of its feasibility assessment as required by NACE SP0206, section 3.3 (incorporated by reference, *see* §507); if any condition that precludes the successful application of ICDA applies, then ICDA may not be used, and another assessment method must be selected. When performing the indirect inspection, the operator must use actual pipeline-specific data, exclusively. The use of assumed pipeline or operational data is prohibited. When calculating the critical inclination angle of liquid holdup and the inclination profile of the pipeline, the operator must consider the accuracy, reliability, and uncertainty of the data used to make those calculations, including, but not limited to, gas flow velocity (including during upset conditions), pipeline elevation profile survey data (including specific profile at features with inclinations such as road crossings, river crossings, drains, valves, drips, etc.), topographical data, and depth of cover. An operator must select locations for direct examination and establish the extent of pipe exposure needed (i.e., the size of the bell hole), to account for these uncertainties and their cumulative effect on the precise location of predicted liquid dropout. [49 CFR 192.927(c)(2)].

3. Detailed examination. An operator must comply with NACE SP0206 (incorporated by reference, *see* §507) in conducting the detailed examination step of the ICDA process. When an operator first uses ICDA for a covered segment, an operator must identify a minimum of two locations for excavation within each covered segment associated with the ICDA region and must perform a detailed examination for internal corrosion at each location using ultrasonic thickness measurements, radiography, or other generally accepted measurement techniques that can examine for internal corrosion or other threats that are being assessed. One location must be the low point (e.g., sag, drip, valve, manifold, dead-leg) within the covered segment nearest to the beginning of the ICDA region. The second location must be further downstream, within the covered segment, near the end of the ICDA region. Whenever corrosion is found during ICDA at any location, the operator must: [49 CFR 192.927(c)(3)]

a. evaluate the severity of the defect (remaining strength) and remediate the defect in accordance with §3333; if the condition is in a covered segment, or in accordance with §§2137 and 2914 if the condition is not in a covered segment; [49 CFR 192.927(c)(3)(i)]

b. expand the detailed examination program to determine all locations that have internal corrosion within the ICDA region, and accurately characterize the nature, extent, and root cause of the internal corrosion. In cases where the internal corrosion was identified within the ICDA region but outside the covered segment, the expanded detailed examination program must also include at least two detailed examinations within each covered segment associated with the ICDA region, at the location within the covered segment(s) most likely to have internal corrosion. One location must be the low point (e.g., sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA region. The second location must be further downstream, within the covered segment. In instances of first use of ICDA for a covered segment, where these locations have already been examined in accordance with Paragraph C.3 of this section, two additional detailed examinations must be conducted within the covered segment; and [49 CFR 192.927(c)(3)(ii)]

c. expand the detailed examination program to evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator's pipeline system with similar characteristics to the ICDA region in which the corrosion was found and remediate identified instances of internal corrosion in accordance with either §3333 or §§2137 and 2914, as appropriate. [49 CFR 192.927(c)(3)(iii)]

4. Post-Assessment Evaluation and Monitoring. An operator must comply with NACE SP0206 (incorporated by reference, *see* §507) in performing the post assessment step of the ICDA process. In addition to NACE SP0206, the evaluation and monitoring process must also include— [49 CFR 192.927(c)(4)]

a. an evaluation of the effectiveness of ICDA as an assessment method for addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals than those specified in §3339. An operator must carry out this evaluation within 1 year of conducting an ICDA; [49 CFR 192.927(c)(4)(i)]

b. 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 [49 CFR 192.927(c)(4)(ii)]

c. continuous monitoring of each ICDA region that contains a covered segment where internal corrosion has been identified by using techniques such as coupons or ultrasonic (UT) sensors or electronic probes, and by periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products. An operator must base the frequency of the monitoring and liquid analysis on results from all integrity assessments that have been conducted in accordance with the requirements of this subpart and risk factors specific to the ICDA region. At a minimum, the monitoring frequency must be two times each calendar year, but at intervals not exceeding 7 1/2 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 §3333 or §§2137 and 2914, as applicable. [49 CFR 192.927(c)(4)(iii)]

i. Conduct excavations of, and detailed examinations at, locations downstream from where the electrolytes might have entered the pipe to investigate and accurately characterize the nature, extent, and root cause of the corrosion, including the monitoring and mitigation requirements of §2130; or [49 CFR 192.927(c)(4)(iii)(A)]

ii. assess the covered segment using another integrity assessment method allowed by this subpart. [49 CFR 192.927(c)(4)(iii)(B)]

5. Other Requirements. The ICDA plan must also include the following: [49 CFR 192.927(c)(5)]

a. criteria an operator will apply in making key decisions (including, but not limited to, ICDA feasibility, definition of ICDA Regions and sub-regions, conditions requiring excavation) in implementing each stage of the ICDA process; [49 CFR 192.927(c)(5)(i)]

b. provisions that the analysis be carried out on the entire pipeline in which covered segments are present, except that application of the remediation criteria of §3333 may be limited to covered segments. [49 CFR 192.927(c)(5)(ii)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 30:1279 (June 2004), amended LR 31:687 (March 2005), LR 33:484 (March 2007), LR 35:2812 (December 2009), LR 50:

### §3329. What Are the Requirements for Using Direct Assessment for Stress Corrosion Cracking (SCCDA)? [49 CFR 192.929]

A. Definition. Stress Corrosion Cracking Direct Assessment (SCCDA) is a process to assess a covered pipe segment for the presence of stress corrosion cracking (SCC) by systematically gathering and analyzing excavation data from pipe having similar operational characteristics and residing in a similar physical environment. [49 CFR 192.929(a)]

B. General Requirements. An operator using direct assessment as an integrity assessment method for addressing SCC in a covered pipeline segment must develop and follow an SCCDA plan that meets NACE SP0204 (incorporated by reference, *see* §507) 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— [49 CFR 192.929(b)]

1. Data Gathering and Integration. An operator's plan must provide for a systematic process to collect and evaluate data for all covered segments to identify whether the conditions for SCC are present and to prioritize the covered segments for assessment in accordance with NACE SP0204, sections 3 and 4, and Table 1 (incorporated by reference, *see* §507). 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 (incorporated by reference, *see* §507) indicate the potential for SCC. This data gathering process must be conducted in accordance with NACE SP0204, section 5.3 (incorporated by reference, *see* §507), and must include, at a minimum, all data listed in NACE SP0204, Table 2 (incorporated by reference, *see* §507). Further, the following factors must be analyzed as part of this evaluation: [49 CFR 192.929(b)(1)];

a. 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); [49 CFR 192.929(b)(1)(i)]

b. the effects of cyclic loading conditions on the susceptibility and propagation of SCC in both high-pH and near-neutral-pH environments; [49 CFR 192.929(b)(1)(ii)]

c. the effects of variations in applied CP, such as overprotection, CP loss for extended periods, and high negative potentials; [49 CFR 192.929(b)(1)(iii)]

d. the effects of coatings that shield CP when disbonded from the pipe; and [49 CFR 192.929(b)(1)(iv)]

e. 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. [49 CFR 192.929(b)(1)(v)]

2. Indirect inspection. In addition to NACE SP0204, the plan's procedures for indirect inspection must include provisions for conducting at least two above ground surveys using the complementary measurement tools most appropriate for the pipeline segment based on an evaluation of integrated data. [49 CFR 192.929(b)(2)]

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. [49 CFR 192.929(b)(3)]

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: [49 CFR 192.929(b)(4)]

a. removing the pipe with SCC; remediating the pipe with a Type B sleeve; performing hydrostatic testing in accordance with Subparagraph B.4.b of this Section; or by grinding out the SCC defect and repairing the pipe. If an operator uses grinding for repair, the operator must also perform the following as a part of the repair procedure: nondestructive testing for any remaining cracks or other defects; a measurement of the remaining wall thickness; and a determination of the remaining strength of the pipe at the repair location that is performed in accordance with §2912 and that meets the design requirements of §§911 and 912 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 §2707, if applicable. [49 CFR 192.929(b)(4)(i)]

b. performing a spike pressure test in accordance with §2306 based upon the class location of the pipeline segment. The MAOP must be no greater than the test pressure specified in §2306.A divided by: 1.39 for Class 1 locations and Class 2 locations that contain Class 1 pipe that has been uprated in accordance with §2711; 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 B.4.a of this Section. [49 CFR 192.929(b)(4)(ii)]

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 §3339. The plan must include the following factors, in addition to any factors the operator determines appropriate: [49 CFR 192.929(b)(5)]

a. the evaluation of discovered crack clusters during the direct examination step in accordance with NACE SP0204, sections 5.3.5.7, 5.4, and 5.5 (incorporated by reference, *see* §507); [49 CFR 192.929(b)(5)(i)]

b. conditions conducive to the creation of a carbonate-bicarbonate environment; [49 CFR 192.929(b)(5)(ii)]

c. conditions in the application (or loss) of CP that can create or exacerbate SCC; [49 CFR 192.929(b)(5)(iii)]

d. operating temperature and pressure conditions, including operating stress levels on the pipe; [49 CFR 192.929(b)(5)(iv)]

e. cyclic loading conditions; [49 CFR 192.929(b)(5)(v)]

f. mechanistic conditions that influence crack initiation and growth rates; [49 CFR 192.929(b)(5)(vi)]

g. the effects of interacting crack clusters; [49 CFR 192.929(b)(5)(vii)]

h. the presence of sulfides; and [49 CFR 192.929(b)(5)(viii)]

i. disbonded coatings that shield CP from the pipe. [49 CFR 192.929(b)(5)(iv)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

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### §3333. What Actions Must Be Taken to Address Integrity Issues? [49 CFR 192.933]

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 §2707. Until documented material properties are available, the operator must use the conservative assumptions in either §2912.E.2 or, if appropriate following a pressure test, in §2912.D.3. [49 CFR 192.933(a)]

1. Temporary Pressure Reduction. [49 CFR 192.933(a)(1)]

a. 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: [49 CFR 192.933(a)(1)(i)]

i. a level not exceeding 80 percent of the operating pressure at the time the condition was discovered; [49 CFR 192.933(a)(1)(i)(A)]

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 [49 CFR 192.933(a)(1)(i)(B)]

iii. a level not exceeding the predicted failure pressure divided by 1.1. [49 CFR 192.933(a)(1)(i)(C)]

b. An operator must determine the predicted failure pressure in accordance with §2912. An operator must notify PHMSA in accordance with §518 if it cannot meet the schedule for evaluation and remediation required under Subsection C or D of this Section and cannot provide safety through a temporary reduction in operating pressure or other action. The operator must document and keep records of the calculations and decisions used to determine the reduced operating pressure, and the implementation of the actual reduced operating pressure, for a period of 5 years after the pipeline has been remediated. [49 CFR 192.933(a)(1)(ii)]

2. …

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, condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under Paragraphs D.1 - D.3 of this Section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable. In cases where a determination is not made within the 180-day period, the operator must notify PHMSA, in accordance with §518, and provide an expected date when adequate information will become available. Notification to PHMSA does not alleviate an operator from the discovery requirements of this Subsection B. [49 CFR 192.933(b)].

C. – D.1. …

a. a metal loss anomaly where a calculation of the remaining strength of the pipe shows a predicted failure pressure determined in accordance with §2912.B less than or equal to 1.1 times the MAOP at the location of the anomaly. [49 CFR 192.933(d)(1)(i)];

b. 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 engineering analyses performed in accordance with §2912.C demonstrate critical strain levels are not exceeded. [49 CFR 192.933(d)(1)(ii)]

c. metal loss greater than 80 percent of nominal wall regardless of dimensions. [49 CFR 192.933(d)(1)(iii)]

d. 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 §2912.D is less than 1.25 times the MAOP. [49 CFR 192.933(d)(1)(iv)]

e. a crack or crack-like anomaly meeting any of the following criteria:[49 CFR 192.933(d)(1)(v)]

i. crack depth plus any metal loss is greater than 50 percent of pipe wall thickness; [49 CFR 192.933(d)(1)(v)(A)]

ii. crack depth plus any metal loss is greater than the inspection tool's maximum measurable depth; or [49 CFR 192.933(d)(1)(v)(B)]

iii. the crack or crack-like anomaly has a predicted failure pressure, determined in accordance with §2912.D, that is less than 1.25 times the MAOP. [49 CFR 192.933(d)(1)(v)(C)]

f. An indication or anomaly that, in the judgment of the person designated by the operator to evaluate the assessment results, requires immediate action. [49 CFR 192.933(d)(1)(vi)]

2. …

a. 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 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless engineering analyses performed in accordance with §2912.C demonstrate critical strain levels are not exceeded. [49 CFR 192.933(d)(2)(i)]

b. a dent with a depth greater than 2 percent of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal or helical (spiral) seam weld, unless engineering analyses performed in accordance with §2912.C demonstrate critical strain levels are not exceeded. [49 CFR 192.933(d)(2)(ii)]

c. 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 §2912.C demonstrate critical strain levels are not exceeded. [49 CFR 192.933(d)(2)(iii)]

d. 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 §2912.B, less than 1.39 times the MAOP for Class 2 locations, and less than 1.50 times the MAOP for Class 3 and 4 locations. For metal loss anomalies in Class 1 locations with a predicted failure pressure greater than 1.1 times MAOP, an operator must follow the remediation schedule specified in ASME/ANSI B31.8S (incorporated by reference, *see* §507), section 7, Figure 4, in accordance with Subsection C of this Section. [49 CFR 192.933(d)(2)(iv)]

e. 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 §2912.B, of less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with §2711, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations. [49 CFR 192.933(d)(2)(v)]

f. 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 §2912.D, is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with §2711, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations. [49 CFR 192.933(d)(2)(vi)]

g. a crack or crack-like anomaly that has a predicted failure pressure, determined in accordance with § 2912.D, that is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with §2711, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations. [49 CFR 192.933(d)(2)(vii)]

3. Monitored Conditions. An operator is not required by this section to schedule remediation of the following less severe conditions but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation. Monitored indications are the least severe and do not require an operator to examine and evaluate them until the next scheduled integrity assessment interval, but if an anomaly is expected to grow to dimensions or have a predicted failure pressure (with a safety factor) meeting a 1-year condition prior to the next scheduled assessment, then the operator must repair the condition: [49 CFR 192.933(d)(3)]

a. a dent with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom 1/3 of the pipe), and for which engineering analyses of the dent, performed in accordance with §2912.C, demonstrate critical strain levels are not exceeded. [49 CFR 192.933(d)(3)(i)]

b. a dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and for which engineering analyses of the dent, performed in accordance with §2912.C, demonstrate critical strain levels are not exceeded. [49 CFR 192.933(d)(3)(ii)]

c. a dent with a depth greater than 2 percent of the pipeline's diameter (0.250 inches in 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 §2912.C, of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties. [49 CFR 192.933(d)(3)(iii)]

d. a dent that has metal loss, cracking, or a stress riser, and where engineering analyses performed in accordance with §2912.C demonstrate critical strain levels are not exceeded. [49 CFR 192.933(d)(3)(iv)]

e. 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 §2912.D, is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with §2711, or greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations. [49 CFR 192.933(d)(3)(v)]

f. a crack or crack-like anomaly for which the predicted failure pressure, determined in accordance with §2912.D, is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with §2711, or greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations. [49 CFR 192.933(d)(3)(vi)]

E. …

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 30:1281 (June 2004), amended LR 31:688 (March 2005), LR 33:485 (March 2007), LR 35:2812 (December 2009), LR 44:1044 (June 2018), LR 46:1600 (November 2020), LR 50:

### §3335. What Additional Preventive and Mitigative Measures Must an Operator Take? [49 CFR 192.935]

A. General Requirements. [49 CFR 192.935(a)].

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 § 3317. 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: [49 CFR 192.933(a)(1)]

a. correcting the root causes of past incidents to prevent recurrence; [49 CFR 192.935(a)(1)(i)]

b. establishing and implementing adequate operations and maintenance processes that could increase safety; [49 CFR 192.935(a)(1)(ii)]

c. establishing and deploying adequate resources for the successful execution of preventive and mitigative measures; [49 CFR 192.935(a)(1)(iii)]

d. installing automatic shut-off valves or remote-control valves; [49 CFR 192.935(a)(1)(iv)]

e. installing pressure transmitters on both sides of automatic shut-off valves and remote-control valves that communicate with the pipeline control center; [49 CFR 192.935(a)(1)(v)]

f. installing computerized monitoring and leak detection systems; [49 CFR 192.935(a)(1)(vi)]

g. replacing pipe segments with pipe of heavier wall thickness or higher strength; [49 CFR 192.935(a)(1)(vii)]

h. conducting additional right-of-way patrols; [49 CFR 192.935(a)(1)(viii)]

i. conducting hydrostatic tests in areas where pipe material has quality issues or lost records; [49 CFR 192.935(a)(1)(ix)]

j. 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; [49 CFR 192.935(a)(1)(x)]

k. re-coating damaged, poorly performing, or disbonded coatings; [49 CFR 192.935(a)(1)(xi)]

l. performing additional depth-of-cover surveys at roads, streams, and rivers; [49 CFR 192.935(a)(1)(xii)]

m. remediating inadequate depth-of-cover; [49 CFR 192.935(a)(1)(xiii)]

n. providing additional training to personnel on response procedures and conducting drills with local emergency responders; and [49 CFR 192.935(a)(1)(xiv)]

o. implementing additional inspection and maintenance programs. [49 CFR 192.935(a)(1)(xv)]

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 §3347.D. [49 CFR 192.935(a)(2)]

B. – D.2. …

3. Perform instrumented leak surveys using leak detector equipment at least twice each calendar year, at intervals not exceeding 7 1/2 months. For unprotected pipelines or cathodically protected pipe where electrical surveys are impractical, instrumented leak surveys must be performed at least four times each calendar year, at intervals not exceeding 4 1/2 months. Electrical surveys are indirect assessments that include close interval surveys, alternating current voltage gradient surveys, direct current voltage gradient surveys, or their equivalent. [49 CFR 192.935(d)(3)]

E. …

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 30:1282 (June 2004), amended LR 31:688 (March 2005), LR 33:485 (March 2007), amended by the Department of Natural Resources, Office of Conservation, LR 38:122 (January 2012), LR 44:1044 (June 2018), LR 46:1600 (November 2020), LR 50:

### §3341. What Is a Low Stress Reassessment? [49 CFR 192.941]

A. – B. …

1. Cathodically Protected Pipe. To address the threat of external corrosion on cathodically protected pipe in a covered segment, an operator must perform an indirect assessment on the covered segment at least once every 7 calendar years. The indirect assessment must be conducted

using one of the following means: indirect examination method, such as a close interval survey; alternating current voltage gradient survey; direct current voltage gradient survey; or the equivalent of any of these methods. An operator must evaluate the cathodic protection and corrosion threat for the covered segment and include the results of each indirect assessment as part of the overall evaluation. This evaluation must also include, at a minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment. [49 CFR 192.941(b)(1)]

2. Unprotected Pipe or Cathodically Protected Pipe Where Electrical Surveys Are Impractical. If an external corrosion assessment is impractical on the covered segment an operator must: [49 CFR 192.941(b)(2)]

a. – C.3. …

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 30:1284 (June 2004), amended LR 31:689 (March 2005), LR 50:

**§3351. Where Does an Operator File a Report? [49 CFR 192.951]**

A. …

B. Any report required by §3351.A, for intrastate facilities subject to the jurisdiction of the Office of Conservation, must be sent concurrently to the Commissioner of Conservation, Office of Conservation, Pipeline Safety Section, P.O. Box 94279 Baton Rouge, LA 70804-9275 or may be transmitted by electronic mail to PipelineInspectors@la.gov.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 30:1286 (June 2004), amended LR 33:487 (March 2007), LR 35:2812 (December 2009), amended by the Department of Natural Resources, Office of Conservation, LR 38:122 (January 2012), LR 50:

# Title 33

# ENVIRONMENTAL QUALITY

## Part V. Hazardous Wastes and Hazardous Materials

## Subpart 3. Natural Resources

## Chapter 301. Transportation of Hazardous Liquids by Pipeline [49 CFR Part 195]

## Subchapter A. General [49 CFR Part 195 Subpart A]

**§30103. Which Pipelines are Covered by this Subpart? [49 CFR 195.1]**

A. – B.3.a. …

b. a pipeline that serves refining, manufacturing, or truck, rail, or vessel terminal facilities, if the pipeline is less than one mile long (measured outside fenced facility grounds) and does not cross an offshore area or a waterway currently used for commercial navigation; [49 CFR 195.1(b)(3)(ii)]

B.4. – C. …

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 15:629 (August 1989), amended LR 18:861 (August 1992), LR 20:439 (1994), LR 21:814 (August 1995), LR 27:1523 (September 2001), LR 29:2804 (December 2003), LR 33:466 (March 2007), LR 35:2791 (December 2009), LR 38:99 (January 2012), LR 46:1604 (November 2020), LR 50:

**§30105. Definitions [49 CFR 195.2]**

A. As used in this Subpart:

* * *

*Entirely Replaced Onshore Hazardous Liquid* or *Carbon Dioxide Pipeline Segments*—for the purposes of §§30258, 30260, and 30418, where two or more miles of pipe, in the aggregate, have been replaced within any 5 contiguous miles within any 24-month period. This definition does not apply to any gathering line.

* * *

*Notification of Potential Rupture*—the notification to, or observation by, an operator of indicia identified in §30417 of a potential unintentional or uncontrolled release of a large volume of commodity from a pipeline. This definition does not apply to any gathering line.

* * *

*Rupture-Mitigation Valve (RMV)*—an automatic shut-off valve (ASV) or a remote-control valve (RCV) that a pipeline operator uses to minimize the volume of hazardous liquid or carbon dioxide released from the pipeline and to mitigate the consequences of a rupture. This definition does not apply to any gathering line.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 15:629 (August 1989), amended LR 18:861 (August 1992), LR 21:815 (August 1995), LR 27:1523 (September 2001), LR 28:83 (January 2002), LR 29:2805 (December 2003), LR 31:675 (March 2005), LR 33:467 (March 2007), LR 38:99 (January 2012), LR 44:1021 (June 2018), LR 46:1604 (November 2020), LR 49:1090 (June 2023), LR 50:

**§30117. What is a regulated rural gathering line and what requirements apply? [49 CFR 195.11]**

A. – 2.b.i. …

ii. Reserved [49 CFR 195.11(b)(2)(ii)]

c. – 4.b. …

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 35:2793 (December 2009), amended LR 49:1090 (June 2023), LR 50:

## Subchapter B. Reporting Accidents and Safety-Related Conditions [Subpart B]

**§30142. Operator Assistance in Investigation [49 CFR 195.60]**

A. If the Department of Energy and Natural Resources investigates an accident, the operator involved shall make available to the representative of the department all records and information that in any way pertain to the accident, and shall afford all reasonable assistance in the investigation of the accident. [49 CFR 195.60]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2813 (December 2003), LR 50:

# Chapter 302. Transportation of Hazardous Liquids by Pipeline—Construction [49 CFR Part 195 Subpart D]

### §30204. Inspection—General [49 CFR 195.204]

A. …

B. Each operator shall notify the Pipeline Safety Section of the Louisiana Department of Energy and Natural Resources, by submitting the Notice of Construction form by electronic mail at PipelineInspectors@la.gov of proposed pipeline construction at least seven days prior to commencement of said construction.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2817 (December 2003), repromulgated LR 30:260 (February 2004), amended LR 44:1025 (June 2018), LR 50:

### §30258. Valves: General [49 CFR 195.258]

A. – D. …

E. If an operator elects to use alternative equivalent technology in accordance with Subsection C or D of this Section, the operator must notify PHMSA in accordance with §30122. The operator must include a technical and safety evaluation in its notice to PHMSA. Valves that are installed as alternative equivalent technology must comply with §§30418, 30419, and 30420. An operator requesting use of manual valves as an alternative equivalent technology must also include within the notification submitted to PHMSA a demonstration that installation of an RMV as otherwise required would be economically, technically, or operationally infeasible. An operator may use a manual pump station valve at a continuously manned station as an alternative equivalent technology. Such a valve used as an alternative equivalent technology would not require a notification to PHMSA in accordance with §30122, but it must comply with §§30419 and 30420. [49 CFR 195.258(e)]

F. The requirements of Subsections C – E of this Section do not apply to gathering lines.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2820 (December 2003), LR 49:1090 (June 2023), LR 50:

### §30260. Valves: Location [49 CFR 195.260]

A. – 7.b. …

8. an operator may submit for PHMSA review, in accordance with §30123, a notification requesting site-specific exemption from the valve installation requirements or valve spacing requirements of Subsections C, E, or F of this Section and demonstrating such exemption would not adversely affect safety. An operator may also submit for PHMSA review, in accordance with §30123, a notification requesting an extension of the compliance deadline requirements for valve installation and spacing of this section because those compliance deadline requirements would be economically, technically, or operationally infeasible for a particular new construction or pipeline replacement project. [49 CFR 195.260(h)]

9. an operator of a gathering line must only comply with the requirements of §30260 effective as of October 4, 2022, and need not comply with the other requirements of this Section. [49 CFR 195.260(i)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2821 (December 2003), amended LR 49:1091 (June 2023), repromulgated LR 49:1224 (July 2023), LR 50:

# Chapter 304. Transportation of Hazardous Liquids by Pipeline—Operation and Maintenance [49 CFR Part 195 Subpart F]

### §30402. Procedural Manual for Operations, Maintenance, and Emergencies [49 CFR 195.402]

A. – C.5.a. …

b. Analysis of rupture and valve shut-offs; preventive and mitigative measures. If a failure or accident on an onshore hazardous liquid or carbon dioxide pipeline involves the closure of a rupture-mitigation valve (RMV), as defined in §30105, or the closure of an alternative equivalent technology, the operator of the pipeline must also conduct a post-failure or post-accident analysis of all the factors that may have impacted the release volume and the consequences of the release and identify and implement operations and maintenance measures to minimize the consequences of a future failure or accident. The analysis must include all relevant factors impacting the release volume and the consequences, including, but not limited to, the following: [49 CFR 195.402(c)(5)(ii)]

i. – F. …

G. Exception. An operator of a gathering line must only comply with the requirements of §30402 effective as of October 4, 2022, and need not comply with the other requirements of this section. [49 CFR 195.402(g)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2824 (December 2003), amended LR 38:106 (January 2012), LR 49:1092 (June 2023), LR 50:

### §30417. Notification of Potential Rupture [49 CFR 195.417]

A. As used in this part, a notification of potential rupture means the notification to, or observation by, an operator (e.g., by or to its controller(s) in a control room, field personnel, nearby pipeline or utility personnel, the public, local responders, or public authorities) of one or more of the below indicia of a potential unintentional or uncontrolled release of a large volume of hazardous liquids or carbon dioxide from a pipeline: [49 CFR 195.417(a)]

1. – 2. …

3. any unanticipated or unexplained rapid release of a large volume of hazardous liquid or carbon dioxide, a fire, or

an explosion, in the immediate vicinity of the pipeline. [49 CFR 195.417(a)(3)]

B. A notification of potential rupture occurs when an operator first receives notice of or observes an event specified in Subsection A of this Section. [49 CFR 195.417(b)]

C. The requirements of this Section do not apply to gathering lines. [49 CFR 195.417(c)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 49:1093 (June 2023), LR 50:

**§30418. Valves: Onshore Valve Shut-Off For Rupture Mitigation [49 CFR 195.418]**

A. – B.2.b.…

3. Laterals. Laterals extending from shut-off segments that contribute less than 5 percent of the total shut-off segment volume may have RMVs or alternative equivalent technologies that meet the actuation requirements of this section at locations other than mainline receipt/delivery points, as long as all of these laterals contributing hazardous liquid or carbon dioxide volumes to the shut-off segment do not contribute more than 5 percent of the total shut-off segment volume, based upon maximum flow volume at the operating pressure. A check valve may be used as an alternative equivalent technology where it is positioned to stop flow into the lateral. Check valves used as an alternative equivalent technology in accordance with this Paragraph are not subject to §30419 but must be inspected, operated, and remediated in accordance with §30420, including for closure and leakage, to ensure operational reliability. An operator using such a valve as an alternative equivalent technology must submit a request to PHMSA in accordance with §30122. [49 CFR 195.418(b)(3)]

4. – C. …

D. Exception. The requirements of this Section do not apply to gathering lines. [49 CFR 195.418(d)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 49:1093 (June 2023), repromulgated LR 49:1225 (July 2023), LR 50:

**§30419. Valve Capabilities [49 CFR 195.419]**

A. – G. …

H. Exception. The requirements of this Section do not apply to gathering lines. [49 CFR 195.419(h)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 49:1094 (June 2023), LR 50:

**§30420. Valve Maintenance [49 CFR 195.420]**

A. …

B. Each operator must, at least twice each calendar year, but at intervals not exceeding 7 1⁄2 months, inspect each mainline valve to determine that it is functioning properly. Each rupture-mitigation valve (RMV), as defined in §30105, and not contained in a gathering line or alternative equivalent technology that is installed under §§30258.C or 30418, must also be partially operated. Operators are not required to close the valve fully during the inspection; a minimum 25 percent valve closure is sufficient to demonstrate compliance, unless the operator has operational information that requires an additional closure percentage for maintaining reliability. [49 CFR 195.420(b)]

C. – G. …

H. The requirements of Subsections D - G of this Section do not apply to gathering lines. [49 CFR 195.420(h)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2828 (December 2003), amended LR 49:1095 (June 2023), repromulgated LR 49:1226 (July 2023), LR 50:

**§30452. Pipeline Integrity Management in High Consequence Areas [49 CFR 195.452]**

A. – I.3. …

4. Emergency Flow Restricting Devices (EFRD). If an operator determines that an EFRD is needed on a pipeline segment that is located in, or which could affect, a high-consequence area (HCA) in the event of a hazardous liquid pipeline release, an operator must install the EFRD. In making this determination, an operator must, at least, evaluate the following factors – the swiftness of leak detection and pipeline shutdown capabilities, the type of commodity carried, the rate of potential leakage, the volume that can be released, topography or pipeline profile, the potential for ignition, proximity to power sources, location of nearest response personnel, specific terrain within the HCA or between the pipeline segment and the HCA it could affect, and benefits expected by reducing the spill size. An RMV installed under this Paragraph must meet all of the other applicable requirements in this part, provided that the requirement of this sentence does not apply to gathering lines. [49 CFR 195.452(i)(4)]

a. – N.5. …

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:753.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2830 (December 2003), amended LR 30:1216 (June 2004), LR 33:471 (March 2007), LR 35:2797 (December 2009), LR 38:108 (January 2012), LR 44:1029 (June 2018), LR 46:1608 (November 2020), LR 49:1096 (June 2023), LR 50:

# Chapter 305. Transportation of Hazardous Liquids by Pipeline—Qualification of Pipeline Personnel [49 CFR Part 195 Subpart G] and Corrosion Control [49 CFR Part 195 Subpart H]

## Subchapter A. Qualification of Pipeline Personnel [49 CFR Part 195 Subpart G]

**§30505. Qualification Program [49 CFR 195.505]**

A. – A.8. …

9. after December 16, 2004, notify the administrator or a state agency participating under 49 U.S.C. Chapter 601 if the operator significantly modifies the program after the administrator or state agency has verified that it complies with this Section. Notifications to PHMSA may be submitted by electronic mail to InformationResources

Manager@dot.gov and to Louisiana Office of Conservation at Pipelineinspectors@la.gov, or mail to ATTN: Information Resources Manager DOT/PHMSA/OPS, East Building, 2nd Floor, E22-321, New Jersey Avenue, S.E. Washington, DC 20590, and to the Pipeline Division Director, Pipeline Safety Section, P.O. Box 94275, Baton Rouge, LA 70804-9275. [49 CFR 195.505(i)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:703.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 29:2835 (December 2003), amended LR 33:471 (March 2007), LR 35:2798 (December 2009), LR 44:1029 (June 2018), LR 50:

**Family Impact Statement**

This Rule has no known impact on family formation, stability, and autonomy as described in R.S. 49:972.

**Poverty Impact Statement**

This Rule has no known impact on poverty as described in R.S. 49:973.

**Small Business Analysis**

This Rule has no known impact on small businesses as described in R.S. 49:965.6.

**Provider Impact Statement**

This Rule has no known impact on providers as described in HCR 170 of 2014.

**Public Comments**

All interested parties will be afforded the opportunity to submit data, views, or arguments, in writing. Written comments will be accepted by hand delivery or USPS only, until 4 p.m., July 21, 2024, at Office of Conservation, Pipeline Division, P.O. Box 94275, Baton Rouge, LA 70804-9275; or Office of Conservation, Pipeline Division, 617 North Third Street, Room 931, Baton Rouge, LA 70802. Reference Docket No. PRA 2024-01. All inquiries should be directed to Michael Peikert at the above addresses or by phone to (225) 219-3799. No preamble was prepared.

Benjamin C. Bienvenu
Commissioner of Conservation