NOTICE OF INTENT

Department of Natural Resources
Office of Conservation

Pipeline Safety
(LAC 43:XI:Chapters 1-43, LAC 43:XIII:Chapters 3-35 and LAC 33:V Chapter 301)

The Department of Natural Resources, Office of Conservation proposes to amend LAC 43:XI, 43:XIII and 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 include minor changes to LAC XI and the changes for LAC 43:XIII & LAC 33:V are required as a part of the Department of 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—Pipeline Division

§101. Definitions

* * *

Intrastate Natural Gas—gas produced, transported, and utilized wholly within the State of Louisiana, through the use of intrastate pipelines or of interstate pipelines where such use of interstate pipelines is or may hereafter be exempt from the control of the Federal Energy Regulatory Commission under the Natural Gas Act or rules and regulations promulgated by the Federal Energy Regulatory Commission thereunder, and gas, wherever produced, which is or may be transported into this state and delivered to an intrastate pipeline in this state to be used or consumed wholly within this state.

* * *

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501-599, 601-606.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 4:76 (March 1978), amended LR 7:80 (March 1981), LR 8:15 (January 1982), repromulgated LR 38:1414 (June 2012).

§3501. Operation, Construction, Extension, Acquisition, Interconnection or Abandonment of Carbon Dioxide Transmission Facilities

A. – G.4. …

H. Certificate of public convenience and necessity shall be issued on the application of any qualified person upon the above findings. The commissioner may attach to any such certificate, and to the exercise of the rights granted thereunder, such reasonable terms and conditions as the public interest may require. Any facility to which a certificate of public convenience and necessity is issued by the commissioner under these rules and regulations and R.S. 30:4(C)(17), R.S. 30:1104(A)(1), and/or R.S. 30:1107 ~~and these rules and regulations~~shall possess the right of expropriation with authority to expropriate private property under the general expropriation laws of the state, including R.S. 19:2(10).

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).

Chapter 39. Transportation of Carbon Dioxide

3907. Matter Incorporated by Reference

A. There are incorporated by reference in this regulation all materials referred to herein. Those materials are hereby made a part of this regulation and have the full force of law. ~~Applicable editions of references approved in ASME/ANSI B31.4 listed in Subsection B of this Section shall apply. Earlier editions may be used for components manufactured, designed, or installed in accordance with those earlier editions at the time they were listed. Later editions will replace those editions listed below as these later editions become effective~~.

~~B. All incorporated materials are available for inspection in the Materials Transportation Bureau, Washington, D.C., and at the Office of the Federal Register, 1100 L Street, N.W., Washington, D.C. In addition, materials incorporated by reference are available as follows.~~

1. All of the materials incorporated by reference are available for inspection from several sources, including the following

a. The Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE., Washington DC 20590. For more information contact 202-366-4046 or go to the PHMSA Web site at: http://www.phmsa.dot.gov/pipeline/regs.

b. The National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202-741-6030 or go to the NARA Web site at: http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html

c. Copies of standards incorporated by reference in this part can also be purchased from the respective standards-developing organization at the addresses provided in the section below.

~~1. American Petroleum Institute (API), 2101 L Street, N.W., Washington, D.C. 20037, or 211 North Ervay, Suite 1700, Dallas, Texas 75201.~~

~~2. The American Society of Mechanical Engineers (ASME), United Engineering Center, 345 East 47th Street, New York, N.Y. 10017.~~

~~3. Manufacturers Standardization Society of the Valve and Fittings Industry (MSS), 5203 Leesburg Pike, Suite 502, Falls Church, VA 22041.~~

~~4. American National Standards Institute (ANSI), 1430 Broadway, New York, N.Y. 10018.~~

~~5. American Society for Testing and Materials (ASTM), 1916 Race Street, Philadelphia, PA 19103.~~

~~C. The full title for the publications incorporated by reference in this regulation and their applicable editions are as follows.~~

~~1. American Petroleum Institute~~

~~a. API Specification 6D *API Specifications for Pipeline Valves*, which may be obtained from the Dallas office (1977).~~

~~b. API Specification 1104 Standard for Welding Pipe Lines and Related Facilities (1980).~~

~~c. API Specification 5L *API Specification for Line Pipe* (1980).~~

~~2. American Society of Mechanical Engineers~~

~~a. ASME Boiler and Pressure Vessel Code, Section VIII, *Pressure Vessels*, Division 1 (1977).~~

~~b. ASME Boiler and Pressure Vessel Code, Section IX, *Welding Qualifications*.~~

~~3. Manufacturers Standardization Society of the Valve and Fitting Industry: MSS SP-75, *Specification for High-Test Wrought Weldings Fittings* (1976).~~

~~4. American National Standards Institute~~

~~a. ANSI BI6.9 Factory Made Wrought Steel Butt-Welded Fittings (1978).~~

~~b. ANSI B3I.4 Liquid Petroleum Transportation Piping Systems (1979).~~

~~5. American Society for Testing and Materials~~

~~a. ASTM Specification A53 Standard Specification for Welded and Seamless Steel Pipe (1979).~~

~~b. ASTM Specification A106 Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service (1979b).~~

~~c. ASTM Specification A134 Standard Specification for Electric-Fusion (Arc)-Welded Steel Plate Pipe, Size 16-inch and Over (1974).~~

~~d. ASTM Specifications A135 Standard Specification for Electric-Resistance Welded Steel Pipe (1979).~~

~~e. ASTM Specification A139 Standard Specification for Electric-Fusion (Arc)-Welded Steel Pipe, Size 4-inch and Over (1974).~~

~~f. ASTM Specification A672 Electric-Fusion-Welded Steel Pipe for High Pressure Service at Moderate Temperatures (1979).~~

~~g. ASTM Specification A691 Carbon and Alloy Steel Pipe Electric-Fusion-Welded for High Pressure Service at High Temperatures (1979).~~

~~h. ASTM Specification A211 Standard Specification for Spiral-Welded Steel or Iron Pipe (1975).~~

~~i. ASTM Specification A333 Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service (1979).~~

~~j. ASTM Specification A381 Standard Specification for Metal-Arc-Welded Steel Pipe for High Pressure Transmission Systems (1979).~~

B. American Petroleum Institute (API), 1220 L Street NW., Washington, DC 20005, phone: 202-682-8000, http://api.org/.

1. API Specification 5L, "Specification for Line Pipe," 45th edition, effective July 1, 2013, (ANSI/API Spec 5L).

2. ANSI/API Specification 6D, "Specification for Pipeline Valves," 23rd edition, effective October 1, 2008, (including Errata 1 (June 2008), Errata 2 (November 2008), Errata 3 (February 2009), Errata 4 (April 2010), Errata 5 (November 2010), and Errata 6 (August 2011); Addendum 1 (October 2009), Addendum 2 (August 2011), and Addendum 3 (October 2012)); (ANSI/API Spec 6D).

3. API Standard 1104, "Welding of Pipelines and Related Facilities," 20th edition, October 2005, (including errata/addendum (July 2007) and errata 2 (2008), (API Std 1104)).

C. ASME International (ASME), Two Park Avenue, New York, NY 10016, 800-843-2763 (U.S/Canada), Web site: http://www.asme.org/.

1. ASME/ANSI B16.9-2007, "Factory-Made Wrought Buttwelding Fittings," December 7, 2007, (ASME/ANSI B16.9).

D. American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, P.O. Box C700, West Conshohocken, PA 119428, phone: 610-832- 9585, Web site: http://www.astm.org/.

1. ASTM A53/A53M-10, "Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless," approved October 1, 2010, (ASTM A53/A53M).

2. ASTM A106/A106M-10, "Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service," approved April 1, 2010, (ASTM A106/A106M).

3. ASTM A381-96 (Reapproved 2005), "Standard Specification for Metal-Arc Welded Steel Pipe for Use with High-Pressure Transmission Systems," approved October 1, 2005, (ASTM A381).

4. ASTM A671/A671M-10, "Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures," approved April 1, 2010, (ASTM A671/A671M

5. ASTM A672/A672M-09, "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures," approved October 1, 2009, (ASTM A672/A672M).

6. ASTM A691/A691M-09, "Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures," approved October 1, 2009, (ASTM A691).

7. ASTM A333/A333M-11, "Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service," approved April 1, 2011, (ASTM A333/A333M

8. 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)

E. Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS), 127 Park St. NE., Vienna, VA 22180, phone: 703-281-6613, Web site: http://www.mss-hq.org/.

1. MSS SP-75-2008 Standard Practice, "Specification for High-Test, Wrought, Butt-Welding Fittings," 2008 edition, (MSS SP 75), IBR approved for §195.118(a).

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:4(C)(17).

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 12:115 (February 1986).

Chapter 43. Design Requirements for Carbon Dioxide Pipelines

§4309. Internal Design Pressure

A. – D. …

E. The seam joint factor used in Subsection A of this Section is determined in accordance with the following table.

Specifications	Pipe Class	Seam Joint Factor
ASTM A53	Seamless Electric resistance welded Furnace lap welded Furnace butt welded	1.00 1.00 0.80 0.60

Specifications	Pipe Class	Seam Joint Factor
ASTM A106	Seamless	1.00
~~ASTM A134~~	~~Electric fusion arc welded~~	~~0.80~~
~~ASTM A135~~	~~Electric resistance welded~~	~~1.00~~
~~ASTM A139~~	~~Electric fusion welded~~	~~0.80~~
~~ASTM A211~~	~~Spiral welded pipe~~	~~0.80~~
ASTM A333	Seamless Welded	1.00 1.00
ASTM A381	Double submerged arc welded	1.00
ASTM A671	Electric-fusion-welded	1.00
ASTM A672	Electric-fusion-welded	1.00
ASTM A691	Electric-fusion-welded	1.00
API 5L	Seamless Electric resistance welded Electric flash welded Submerged arc welded Furnace lap welded Furnace butt welded	1.00 1.00 1.00 1.00 0.80 0.60

1. – F. …

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:4(C)(17).

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 12:115 (February 1986).

Title 43
NATURAL RESOURCES

Subpart 2. Transportation of Natural Gas and Other Gas by Pipeline<u>; Annual Incident and Other Reporting</u> [49 CFR Part 191]

Chapter 3. Annual Reports, Incident Reports and Safety Related Condition Reports [49 CFR Part 191]

§301. Scope [49 CFR 191.1]

A. This Chapter prescribes requirements for the reporting of incidents, safety-related conditions, annual pipeline summary data, National Registry of Operators information, and other miscellaneous conditions by operators of underground natural gas storage facilities and natural gas pipeline facilities located in <u>Louisiana</u> ~~the United States or Puerto Rico~~, including underground natural gas storage facilities and pipelines within the limits of the Outer Continental Shelf, as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331). <u>This part applies to offshore gathering lines (except as provided in Subsection B of this section) and to onshore gathering lines, including Type R gathering lines as determined in § 508 of this Part.</u> [49 CFR 191.1(a)]

B. – B.1 …

2. pipelines on the Outer Continental Shelf (OCS) that are producer operated and cross into state waters without first connecting to a transporting operator's facility on the OCS, upstream (generally seaward) of the last valve on the last production facility on the OCS. Safety equipment protecting PHMSA-regulated pipeline segments is not excluded. Producing operators for those pipeline segments upstream of the last valve of the last production facility on the OCS may petition the administrator, or designee, for approval to operate under PHMSA regulations governing pipeline design, construction, operation, and maintenance under 49 CFR 190.9; <u>or</u> [49 CFR 191.1(b)(2)]

3. pipelines on the Outer Continental Shelf upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator; or [49 CFR 191.1(b)(3)]

~~4. Onshore Gathering of Gas— [49 CFR 191.1 (b)(4)]~~

~~a. through a pipeline that operates at less than 0 psig (0 kPa); [49 CFR 191.1(b)(4)(i)]~~

~~b. through a pipeline that is not a regulated onshore gathering line (as determined in §508 of this Part); and [191.(b)(4)(ii)]~~

C. <u>Sections 322.B and C and 323 do not apply to the onshore gathering of gas</u> [49 CFR 191.1(c)]

1. <u>through a pipeline that operates at less than 0 psig (0 kPa)</u> [49 CFR 191.1(c)(1)]

2. <u>through a pipeline that is not a regulated onshore gathering line; or</u> [49 CFR 191.1(c)(2)]

3. <u>Within inlets of the Gulf of Mexico, except for the requirements in § 2712 of this Part.</u> [49 CFR 191.1(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, LR 9:218 (April 1983), amended LR 10:510 (July 1984), LR 11:255 (March 1985), LR 18:854 (August 1992), LR 27:1536 (September 2001), LR 30:1220 (June 2004), LR 33:473 (March 2007), LR 38:110 (January 2012), LR 45:66 (January 2019).

§307. Report Submission Requirements [49 CFR 191.7]

A. – A.1. …

~~a. Annual report information must only include data for intrastate facilities subject to the jurisdiction of the Office of Conservation.~~

B. – 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, LR 9:219 (April 1983), amended LR 10:510 (July 1984), LR 11:255 (March 1985), LR 20:442 (April 1994), LR 27:1536 (September 2001), LR 30:1221 (June 2004), LR 31:679 (March 2005), LR 33:473 (March 2007), LR 35:2800 (December 2009), LR 38:110 (January 2012), LR 44:1032 (June 2018), LR 45:66 (January 2019).

§303. Definitions [49 CFR 191.3]

A. …

* * *

<u>*Regulated onshore gathering*— a Type A, Type B, or Type C gas gathering pipeline system as determined in § 508 of this Part.</u>

<u>*Reporting-regulated gathering*— a Type R gathering line as determined in § 508 of this Part. A Type R gathering line is subject only to this Subpart.</u>

* * *

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 11:255 (March

1985), amended LR 18:854 (August 1992), LR 20:442 (April 1994), LR 27:1536 (September 2001), LR 30:1221 (June 2004), LR 33:473 (March 2007), LR 38:110 (January 2012), LR 44:1032 (June 2018), LR 45:66 (January 2019), LR 46:1575 (November 2020), LR. 47:1140 (August 2021).

§315. Transmission Systems; Gathering Systems; and Liquefied Natural Gas Facilities: Incident Report [49 CFR 191.15]

A. Pipeline Systems ~~Transmission or Gathering. Each operator of a transmission or a gathering pipeline system must submit DOT Form PHMSA F 7100.2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under §305 of this Chapter~~. [49 CFR 191.15(a)]

1. Transmission, offshore gathering, or regulated onshore gathering. Each operator of a transmission, offshore gathering, or a regulated onshore gathering pipeline system must submit Department of Transportation (DOT) Form PHMSA F 7100.2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under § 305. [49 CFR 191.15(a)(1)]

2. Reporting-regulated gathering. Each operator of a reporting-regulated gathering pipeline system must submit DOT Form PHMSA F 7100.2–2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under § 305 that occurs after May 16, 2022. [49 CFR 191.15(a)(2)]

B. – 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 9:219 (April 1983), amended LR 10:511 (July 1984), LR 11:255 (March 1985), LR 30:1222 (June 2004), LR 38:111 (January 2012), LR 45:67 (January 2019), LR 46:1575 (November 2020).

§317. Transmission Systems; Gathering Systems; and Liquefied Natural Gas Facilities: Annual Report [49 CFR 191.17]

A. Pipeline Systems~~Transmission or Gathering. Each operator of a transmission or a gathering pipeline system must submit an annual report for that system on DOT Form PHMSA 7100.2.1. This report must be submitted each year, not later than March 15, for the preceding calendar year, except that for the 2010 reporting year the report must be submitted by June 15, 2011.~~ [49 CFR 191.17(a)]

1. Transmission or regulated onshore gathering. Each operator of a transmission or a regulated onshore gathering pipeline system must submit an annual report for that system on DOT Form PHMSA F 7100.2-1. This report must be submitted each year, not later than March 15, for the preceding calendar year. [49 CFR 191.17(a)(1)]

2. Type R gathering. Beginning with an initial annual report submitted in March 2023 for the 2022 calendar year, each operator of a reporting-regulated gas gathering pipeline system must submit an annual report for that system on DOT Form PHMSA F 7100.2-3. This report must be submitted each year, not later than March 15, for the preceding calendar year. [49 CFR 191.17(a)(2)]

B. – 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 9:219 (April 1983), amended LR 10:511 (July 1984), LR 11:256 (March 1985), LR 30:1222 (June 2004), LR 38:111 (January 2012), LR 45:67 (January 2019), LR 46:1575 (November 2020).

§323. Reporting Safety-Related Conditions [49 CFR 191.23]

A. – B. …

1. exists on a master meter system, a reporting-regulated gathering pipeline a Type C gas gathering pipeline with an outside diameter of 12.75 inches or less, a Type C gas gathering pipeline covered by the exception in § 509F.1 of this subchapter and therefore not required to comply with § 509.E.2.b, or a customer-owned service line; [49 CFR 191.23(b)(1)]

B.2. – B.5. …

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, amended LR 30:1223 (June 2004), LR 45:68 (January 2019), LR 46:1576 (November 2020).

§329. National Pipeline Mapping System [49 CFR 191.29]

A. – B. …

C. This section does not apply to gathering pipelines. [49 CFR 191.29(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 44:1033 (June 2018).

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. …

* * *

Composite materials - means materials used to make pipe or components manufactured with a combination of either steel and/or plastic and with a reinforcing material to maintain its circumferential or longitudinal strength.

* * *

Entirely replaced onshore transmission pipeline segments - means, 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.

* * *

Notification of potential rupture - means 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.

* * *

Rupture-mitigation valve (RMV) - means 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.

* * *

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).

§508. How are Onshore Gathering Lines and Regulated Onshore Gathering Lines Determined? [49 CFR 192.8]

A. – A.4. …

5. For new, replaced, relocated, or otherwise changed gas gathering pipelines installed after May 16, 2022, the endpoint of gathering under sections 2.2(a)(1)(E) and 2.2.1.2.6 of API RP 80 (incorporated by reference, see § 507)--also known as “incidental gathering”--may not be used if the pipeline terminates 10 or more miles downstream from the furthermost downstream endpoint as defined in paragraphs 2.2(a)(1)(A) through (a)(1)(D) of API RP 80 (incorporated by reference, see § 507) and this section. If an “incidental gathering” pipeline is 10 miles or more in length, the entire portion of the pipeline that is designated as an incidental gathering line under 2.2(a)(1)(E) and 2.2.1.2.6 of API RP 80 shall be classified as a transmission pipeline subject to all applicable regulations in this chapter for transmission pipelines. [49 CFR 192.8(a)(5)]

B. Each operator must determine and maintain for the life of the pipeline records documenting the methodology by which it calculated the beginning and end points of each onshore gathering pipeline it operates, as described in the second column of the table to Paragraph C.2 of this Section, by:~~For purposes of §509, "regulated onshore gathering line" means~~ [49 CFR 192.8(b)]

1. November 16, 2022, or before the pipeline is placed into operation, whichever is later; ~~oreach onshore gathering line (or segment of onshore gathering line) with a feature described in the second column that lies in an area described in the third column~~ [49 CFR 192.8(b)(1)]

2. An alternative deadline approved by the Pipeline and Hazardous Materials Safety Administration (PHMSA). The operator must notify PHMSA and State or local pipeline safety authorities, as applicable, no later than 90 days in advance of the deadline in Subsection B.1 of this section. The notification must be made in accordance with § 518 and must include the following information:~~as applicable, additional lengths of line described in the fourth column to provide a safety buffer~~ [49 CFR 192.8(b)(2)]

a. Description of the affected facilities and operating environment; [49 CFR 192.8(b)(2)(i)]

b. Justification for an alternative compliance deadline; and [192.(b)(2)(ii)]

c. Proposed alternative deadline. [192.(b)(2)(iii)]

C. For purposes of part 191 of this chapter and Sec. 192.9, the term “regulated onshore gathering pipeline” means: [49 CFR 192.8(c)]

1. Each Type A, Type B, or Type C onshore gathering pipeline (or segment of onshore gathering pipeline) with a feature described in the second column of the table to Paragraph C.2 of this Section that lies in an area described in the third column; and [49 CFR 192.8(c)(1)]

2. As applicable, additional lengths of pipeline described in the fourth column to provide a safety buffer: [49 CFR 192.8(c)(2)]

3. A Type R gathering line is subject to reporting requirements under part 191 of this chapter but is not a regulated onshore gathering line under this part. [49 CFR 192.8(c)(3)]

4. For the purpose of identifying Type C lines in table 1 to Paragraph C.2 of this Section, if an operator has not calculated MAOP consistent with the methods at §§ 2719.A or C.1, the operator must either: [49 CFR 192.8(c)(4)]

a. Calculate MAOP consistent with the methods at § 2719.A or C.1; or [49 CFR 192.8(c)(4)(i)]

b. Use as a substitute for MAOP the highest operating pressure to which the segment was subjected during the preceding 5 operating years. [192.8(c)(4)(ii)]

Type	Feature	Area	Safety Buffer
A	—Metallic and the MAOP produces a hoop stress of 20 percent or more of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in Chapter 9 of this Subpart. —Non-metallic and the MAOP is more than 125 psig (862 kPa).	Class 2, 3, or 4 location (see § 505).	None.

Type	Feature	Area	Safety Buffer
B	—Metallic and the MAOP produces a hoop stress of less than 20 percent of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in Chapter 9 of this Subpart. —Non-metallic and the MAOP is 125 psig (862 kPa) or less.	Area 1. Class 3 or 4 location. Area 2. An area within a Class 2 location the operator determines by using any of the following three methods: (a) A Class 2 location. (b) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1 mile (1.6 km) of pipeline and including more than 10 but fewer than 46 dwellings. (c) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1000 feet (305 m) of pipeline and including 5 or more dwellings.	If the gathering line is in Area 2(b) or 2(c), the additional lengths of line extend upstream and downstream from the area to a point where the line is at least 150 feet (45.7 m) from the nearest dwelling in the area. However, if a cluster of dwellings in Area 2 (b) or 2(c) qualifies a line as Type B, the Type B classification ends 150 feet (45.7 m) from the nearest dwelling in the cluster.
C	Outside diameter greater than or equal to 8.625 inches and any of the following: —Metallic and the MAOP produces a hoop stress of 20 percent or more of SMYS; —If the stress level is unknown, segment is metallic and the MAOP is more than 125 psig (862 kPa); or —Non-metallic and the MAOP is more than 125 psig (862 kPa)	Class 1 location	None.
R	—Metallic and the MAOP produces a hoop stress of less than 20 percent of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in Chapter 9 of this Subpart. —Non-metallic and the MAOP is 125 psig (862 kPa) or less.	Class 1 and Class 2 locations	None.

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 33:476 (March 2007).

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

A. – 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, 1139.F, 1165, 1307.C, 1515.E, ~~and~~ 2305~~;~~, 2734, and 2735. [49 CFR 192.9(d)(1)]

D.2. – D.8. …

E. Type C lines. The requirements for Type C gathering lines are as follows.~~Compliance deadlines. An operator of a regulated onshore gathering line must comply with the following deadlines, as applicable~~ [49 CFR 192.9(e)].

1. An operator of a Type C onshore gathering line with an outside diameter greater than or equal to 8.625 inches must comply with the following requirements:~~An operator of a new, replaced, relocated, or otherwise changed line must be in compliance with the applicable requirements of this Section by the date the line goes into service, unless an exception in §513 applies~~ [49 CFR 192.9(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 through 17 and Chapter 23 of this Part applicable to transmission lines. Compliance with §§ 717, 927, 1139.E, 1139.F, 1165, 1307.C, 1515.E, ~~and~~ 2305, 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 § 2145; [192.9(e)(1)(ii)]

c. Carry out a damage prevention program under § 2714; [192.9(e)(1)(iii)]

d. Develop and implement procedures for emergency plans in accordance with § 2715; [192.9(e)(1)(iv)]

e. Develop and implement a written public awareness program in accordance with § 2716; [192.9(e)(1)(v)]

f. Install and maintain line markers according to the requirements for transmission lines in § 2907; and [192.9(e)(1)(vi)]

g. Conduct leakage surveys in accordance with the requirements for transmission lines in § 2906 using leak-detection equipment, and promptly repair hazardous leaks in accordance with § 2903.C. [192.9(e)(1)(vii)]

2. An operator of a Type C onshore gathering line with an outside diameter greater than 12.75 inches must comply with the requirements in Paragraph E.1 of this Section and the following~~If a regulated onshore gathering line existing on April 14, 2006 was not previously subject to this Part, an operator has until the date stated in the second column to comply with the applicable requirement for the line listed in the first column, unless the administrator finds a later deadline is justified in a particular case:~~ [49 CFR 192.9(e)(2)]

a. If the pipeline contains plastic pipe, the operator must comply with all applicable requirements of this part for plastic pipe or components. This does not include pipe and components made of composite materials that incorporate plastic in the design; and [49 CFR 192.9(e)(2)(i)]

b. Establish the MAOP of the pipeline under Subsections 2719.A or C and maintain records used to establish the MAOP for the life of the pipeline. [192.9(e)(2)(ii)]

~~Requirement~~	~~Compliance Deadline~~
~~Control corrosion according to Chapter 21 requirements for transmission lines.~~	~~April 15, 2009~~
~~Carry out a damage prevention program under §2714.~~	~~October 15, 2007~~
~~Establish MAOP under §2719~~	~~October 15, 2007~~
~~Install and maintain line markers under §2907.~~	~~April 15, 2008~~
~~Establish a public education program under §2716.~~	~~April 15, 2008~~
~~Other provisions of this Part as required by Subsection C of this Section for Type A lines.~~	~~April 15, 2009~~

~~3. If, after April 14, 2006, a change in class location or increase in dwelling density causes an onshore gathering line to be a regulated onshore gathering line, the operator has 1 year for Type B lines and 2 years for Type A lines after the line becomes a regulated onshore gathering line to comply with this Section [49 CFR 192.9(e)(3)].~~

F. Exceptions. [49 CFR 192.9(f)].

1. Compliance with Subparagraphs E.1.b, e, f, and g and E.2.a and b of this Section is not required for pipeline segments that are 16 inches or less in outside diameter if one of the following criteria are met: [49 CFR 192.9(f)(1)]

a. Method 1. The segment is not located within a potential impact circle containing a building intended for human occupancy or other impacted site. The potential impact circle must be calculated as specified in Section 3303, except that a factor of 0.73 must be used instead of 0.69. The MAOP used in this calculation must be determined and documented in accordance with Clause E.2.b of this Section.[49 CFR 192.9(f)(1)(i)]

b. Method 2. The segment is not located within a class location unit (see § 505) containing a building intended for human occupancy or other impacted site. [49 CFR 192.9(f)(1)(ii)]

2. Clause E.1.a of this Section is not applicable to pipeline segments 40 feet or shorter in length that are replaced, relocated, or changed on a pipeline existing on or before May 16, 2022. [49 CFR 192.9(f)(2)]

3. For purposes of this section, the term "building intended for human occupancy or other impacted site" means any of the following: [49 CFR 192.9(f)(3)].

a. Any building that may be occupied by humans, including homes, office buildings factories, outside recreation areas, plant facilities, etc.; [49 CFR 192.9(f)(3)(i)]

b. A small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period (the days and weeks need not be consecutive); or [49 CFR 192.9(f)(3)(ii)]

c. Any portion of the paved surface, including shoulders, of a designated interstate, other freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes. [49 CFR 192.9(f)(3)(iii)]

G. Compliance deadlines. An operator of a regulated onshore gathering line must comply with the following deadlines, as applicable. [49 CFR 192.9(g)]

1. An operator of a new, replaced, relocated, or otherwise changed line must be in compliance with the applicable requirements of this section by the date the line goes into service, unless an exception in § 513 applies. [49 CFR 192.9(g)(1)]

2. If a Type A or Type B regulated onshore gathering pipeline existing on April 14, 2006, was not previously subject to this part, an operator has until the date stated in the second column to comply with the applicable requirement for the pipeline listed in the first column, unless the Administrator finds a later deadline is justified in a particular case: [49 CFR 192.9(g)(2)]

Requirement	Compliance Deadline
Control corrosion according to Chapter 21 requirements for transmission lines.	April 15, 2009
Carry out a damage prevention program under §2714.	October 15, 2007
Establish MAOP under §2719	October 15, 2007
Install and maintain line markers under §2907.	April 15, 2008
Establish a public education program under §2716.	April 15, 2008
Other provisions of this Part as required by Subsection C of this Section for Type A lines.	April 15, 2009

3. If, after April 14, 2006, a change in class location or increase in dwelling density causes an onshore gathering pipeline to become a Type A or Type B regulated onshore gathering line, the operator has 1 year for Type B lines and 2 years for Type A lines after the pipeline becomes a regulated onshore gathering pipeline to comply with this section. [49 CFR 192.9(g)(3)]

4. If a Type C gathering pipeline existing on or before May 16, 2022, was not previously subject to this Subpart, an operator must comply with the applicable requirements of this Section, except for Subsection H of this Section, on or before: [49 CFR 192.9(g)(4)]

a. May 16, 2023; or [49 CFR 192.9(g)(4)(i)]

b. An alternative deadline approved by PHMSA. The operator must notify PHMSA and State or local pipeline safety authorities, as applicable, no later than 90 days in advance of the deadline in paragraph (b)(1) of this section. The notification must be made in accordance with § 518 and must include a description of the affected facilities and operating environment, the proposed alternative deadline for each affected requirement, the justification for each alternative compliance deadline, and actions the operator will take to ensure the safety of affected facilities. [49 CFR 192.9(g)(4)(ii)]

5. If, after May 16, 2022, a change in class location, an increase in dwelling density, or an increase in MAOP causes a pipeline to become a Type C gathering pipeline, or causes a Type C gathering pipeline to become subject to additional Type C requirements (see Subsection F of this Section), the operator has 1 year after the pipeline becomes subject to the additional requirements to comply with this section. [49 CFR 192.9(g)(5)]

H. Composite materials. Pipe and components made with composite materials not otherwise authorized for use under this part may be used on Type C gathering pipelines if the following requirements are met: [49 CFR 192.9(h)]

1. Steel and plastic pipe and components must meet the installation, construction, initial inspection, and initial testing requirements in Chapters 7 through 17 and 23 of this Subpart applicable to transmission lines. [49 CFR 192.9(h)(1)]

2. Operators must notify PHMSA in accordance with § 518 at least 90 days prior to installing new or replacement pipe or components made of composite materials otherwise not authorized for use under this part in a Type C gathering pipeline. The notifications required by this section must include a detailed description of the pipeline facilities in which pipe or components made of composite materials would be used, including: [49 CFR 192.9(h)(2)]

a. The beginning and end points (stationing by footage and mileage with latitude and longitude coordinates) of the pipeline segment containing composite pipeline material and the counties and States in which it is located; [49 CFR 192.9(h)(2)(i)]

b. A general description of the right-of-way including high consequence areas, as defined in § 3305; [49 CFR 192.9(h)(2)(ii)]

c. Relevant pipeline design and construction information including the year of installation, the specific composite material, diameter, wall thickness, and any manufacturing and construction specifications for the pipeline; [49 CFR 192.9(h)(2)(iii)]

d. Relevant operating information, including MAOP, leak and failure history, and the most recent pressure test (identification of the actual pipe tested, minimum and maximum test pressure, duration of test, any leaks and any test logs and charts) or assessment results; [49 CFR 192.9(h)(2)(iv)]

e. An explanation of the circumstances that the operator believes make the use of composite pipeline material appropriate and how the design, construction, operations, and maintenance will mitigate safety and environmental risks; [49 CFR 192.9(h)(2)(v)]

f. An explanation of procedures and tests that will be conducted periodically over the life of the composite pipeline material to document that its strength is being maintained; [49 CFR 192.9(h)(2)(vi)]

g. Operations and maintenance procedures that will be applied to the alternative materials. These include procedures that will be used to evaluate and remediate anomalies and how the operator will determine safe operating pressures for composite pipe when defects are found; [49 CFR 192.9(h)(2)(vii)]

h. An explanation of how the use of composite pipeline material would be in the public interest; and [49 CFR 192.9(h)(2)(viii)]

i. A certification signed by a vice president (or equivalent or higher officer) of the operator's company that operation of the applicant's pipeline using composite pipeline material would be consistent with pipeline safety. [49 CFR 192.9(h)(2)(iv)]

3. Repairs or replacements using materials authorized under this part do not require notification under this Section. [49 CFR 192.9(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).

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

A. No person may operate a segment of pipeline listed in the first column of Paragraph A.3 of this Section that is readied for service after the date in the second column, unless: [49 CFR 192.13(a)]

A.1. – A.2. …

3. The compliance deadlines are as follows: [49 CFR 192.13(a)(3)]

Pipeline	Date
Offshore gathering line.	July 31, 1977
Regulated onshore gathering line to which this Subpart did not apply until April 14, 2006	March 15 2007
Regulated onshore gathering pipeline to which this part did not apply until May 16, 2022	May 16, 2023..
All other pipelines.	March 12, 1971

B. No person may operate a segment of pipeline listed in the first column that is replaced, relocated, or otherwise changed after the date in the second column, unless the replacement, relocation, or change has been made according to the requirements in this Subpart [49 CF.R 192.13(b)]

Pipeline	Date
Offshore gathering line.	July 31, 1977
Regulated onshore gathering line to which this Subpart did not apply until April 14, 2006.	March 15 2007
Regulated onshore gathering pipeline to which this part did not apply until May 16, 2022	May 16, 2023
All other pipelines.	November 12, 1970

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 9:220 (April 1983), amended LR 10:511 (July 1984), LR 30:1227 (June 2004), LR 33:477 (March 2007).

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

A. – B. …

C. ~~Unless otherwise specified, if the notification is made pursuant to §2305.B, §2707.E.5, §2724.C.2.c, §2724.C.6, §2732.B.3, §2910.C.7, §2912.E.2.i.e, E.2.a.v, or §3337.C.7 to use a different integrity assessment method, analytical method, sampling approach, or technique (i.e., "other technology") that differs from that prescribed in those Sections, the operator must notify PHMSA at least 90 days in advance of using the other technology. An operator may proceed to use the other technology 91 days after submittal of the notification unless it receives a letter from the Associate Administrator for Pipeline Safety informing the operator that PHMSA objects to the proposed use of other technology or that PHMSA requires additional time to conduct its review.~~ Unless otherwise specified, if an operator submits, pursuant to §§ 508, 509, 1139, 2306, 2707, 2719, 2724, 2732, 2734, 2736, 2910, 2912, 2945, 3321, or3337, 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).

Chapter 9. Pipe Design [49 CFR Part 192 Subpart C]

§921. Design of Plastic Pipe [49 CFR 192.121]

A. – C.2.d. …

Table 1 to Subparagraph C.2.d
PE Pipe: Minimum Wall Thickness and SDR Values

Pipe Size (inches)	Minimum Wall Thickness	Corresponding SDR (values)
1/2" CTS	0.090	7
1/2" IPS	0.090	9.3
3/4" CTS	0.090	9.7
3/4" IPS	0.095	11
1" CTS	~~0.119~~.099	11
1" IPS	0.119	11
1 1/4" IPS	0.151	11
1 1/2" IPS	0.173	11
2"	0.216	11
3"	0.259	13.5
4"	0.265	17
6"	0.315	21
8"	0.411	21
10"	0.512	21
12"	0.607	21
16	.762	21
18	.857	21
20	.952	21
22	1.048	21
24	1.143	21

D. – 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 9:222 (April 1983), amended LR 10:515 (July 1984), LR 24:1308 (July 1998), LR 27:1538 (September 2001), LR 30:1231 (June 2004), LR 31:682 (March 2005), LR 33:478 (March 2007), LR 35:2804 (December 2009), LR 38:115 (January 2012), repromulgated LR 38:828 (March 2012), amended LR 44:1037 (June 2018), LR 46:1582 (November 2020), LR. 47:1141 (August 2021).

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

§1110. Passage of Internal Inspection Devices [49 CFR 192.150]

A. – B.7.a. …

b. if the design includes taps for lateral connections, the operator can demonstrate, based on investigation or experience, that there is no reasonably practical alternative under the design circumstances to the use of a tap that will obstruct the passage of instrumented internal inspection devices; ~~and~~ [49 CFR 192.150(b)(7)(ii)]

8. Gathering lines; and~~other piping that, under 49 CFR Part 190.9 and LAC 43:XI.Subpart 3 the commissioner/administrator finds in a particular case would be impracticable to design and construct to accommodate the passage of instrumented internal inspection devices.~~ [49 CFR 192.150(b)(8)]

9. Other piping that, under 49 CFR Part 190.9 and LAC 43:XI.Subpart 3 the commissioner/administrator finds in a particular case would be impracticable to design and construct to accommodate the passage of instrumented internal inspection devices. [49 CFR 192.150(b)(9)]

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 21:821 (August 1995), amended LR 27:1539 (September 2001), LR 30:1233 (June 2004), LR 31:682 (March 2005), LR 33:479 (March 2007), LR 46:1584 (November 2020).

§1113. Components Fabricated by Welding [49 CFR 192.153]

A. – E.2.a …

b. A prefabricated unit or pressure vessel installed on or after October 1, 2021 must be tested for the duration specified in either §2305.C or D, 2307.C, or §2309.A, whichever is applicable for the pipeline in which the component is being installed. [49 CFR 192.153(e)(2)(ii)]

E.3. – E.6.b. …

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 9:223 (April 1983), amended LR 10:516 (July 1984), LR 20:444 (April 1994), LR 27:1539 (September 2001), LR 30:1234 (June 2004), LR 44:1037 (June 2018), LR.

§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. All RMVs and alternative equivalent technologies installed pursuant to this Subsection must meet the requirements of §§ 2734 and 2736. Exempted from this Subsection's installation requirements are pipeline segments in Class 1, or Class 2 locations that have a potential impact radius (PIR), as defined in § 3303, of 150 feet or less. 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 § 318, 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 §§ 2734 and 2736. The requirements of this Subsection apply when the applicable pipeline replacement project involves a valve, either through addition, replacement, or removal. This Subsection's installation requirements do not apply to pipe segments in Class 1 or Class 2 locations that have a PIR, as defined in § 3303, that is less than or equal to 150 feet. An operator may request an extension of the installation compliance deadline requirements of this paragraph if it can demonstrate to PHMSA, in accordance with the notification procedures in § 192.18, that those installation compliance deadlines would be economically, technically, or operationally infeasible for a particular pipeline replacement project. [49 CFR 192.179(f)]

G. If an operator elects to use alternative equivalent technology in accordance with paragraphs (e) or (f) of this section, the operator must notify PHMSA in accordance with the procedures in § 192.18. 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 §§ 2734 and 2736. 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 compressor station valve at a continuously manned station as an alternative equivalent technology, and use of such valve would not require a notification to PHMSA in accordance with § 518, but it must comply with § 2736. [49 CFR 192.179(g)]

H. The valve spacing requirements of Subsection A of this section do not apply to pipe replacements on a pipeline if the distance between each point on the pipeline and the nearest valve does not exceed: [49 CFR 192.179(h)]

1. Four (4) miles in Class 4 locations, with a total spacing between valves no greater than 8 miles; [49 CFR 192.179(h)(1)]

2. Seven-and-a-half (7½) miles in Class 3 locations, with a total spacing between valves no greater than 15 miles; or [49 CFR 192.179(h)(2)]

3. Ten (10) miles in Class 1 or 2 locations, with a total spacing between valves no greater than 20 miles. [49 CFR 192.179(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).

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

§1511. Plastic Pipe [49 CFR 192.281]

A. – B.3. …

C. Heat-Fusion Joints. Each heat-fusion joint on a PE pipe or component, except for electrofusion joints, must comply with ASTM F2620~~-12~~ (incorporated by reference in §507), or an alternative written procedure that has been demonstrated to provide an equivalent or superior level of safety and has been proven by test or experience to produce strong gastight joints, and the following. [49 CFR 192.281(c)]

C.1. – E.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 9:231 (April 1983), amended LR 10:523 (July 1984), LR 20:445 (April 1994), LR 24:1309 (July 1998), LR 30:1243 (June 2004), LR 38:116 (January 2012), LR 44:1039 (June 2018), LR 46:1585 (November 2020), LR. 47:1144 (August 2021).

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

§2103. How Does this Chapter Apply to Converted Pipelines and Regulated Onshore Gathering Lines? [49 CFR 192.452]

A. …

B. Type A and B onshore gathering lines. For any Type A or Type B regulated onshore gathering line under §509 existing on April 14, 2006, that was not previously subject to this Subpart, and for any onshore gathering line that becomes a regulated onshore gathering line under §509 after April 14, 2006, because of a change in class location or increase in dwelling density.~~Regulated onshore gathering lines. For any regulated onshore gathering line under §509 existing on April 14, 2006, that was not previously subject to this Subpart, and for any onshore gathering line that becomes a regulated onshore gathering line under §509 after April 14, 2006, because of a change in class location or increase in dwelling density~~ [49 CFR 192.452(b)]

1. ~~the requirements of this Chapter specifically applicable to pipelines installed before August 1, 1971, apply to the gathering line regardless of the date the pipeline was actually installed [49 CFR 192.452(b)(1)]; and~~

2. ~~the requirements of this Chapter specifically applicable to pipelines installed after July 31, 1971, apply only if the pipeline substantially meets those requirements [49 CFR 192.452(b)(2)].~~

C. Type C onshore regulated gathering lines. For any Type C onshore regulated gathering pipeline under §509 existing on May 16, 2022, that was not previously subject to this Subpart, and for any Type C onshore gas gathering pipeline that becomes subject to this subpart after May 16, 2022, because of an increase in MAOP, change in class location, or presence of a building intended for human occupancy or other impacted site: [49 CFR 192.452(c)]

1. The requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, apply to the gathering line regardless of the date the pipeline was actually installed; and[49 CFR 192.452(c)(1)]

2. The requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply only if the pipeline substantially meets those requirements. [49 CFR 192.452(c)(2)]

D. Regulated onshore gathering lines generally. Any gathering line that is subject to this subpart per §509 at the time of construction must meet the requirements of this subpart applicable to pipelines installed after July 31, 1971. [49 CFR 192.452(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 9:235 (April 1983), amended LR 10:527 (July 1984), LR 30:1252 (June 2004), LR 33:480 (March 2007).

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

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

A. If a class location change on a transmission pipeline occurs after October 5, 2022 and results in pipe replacement, of 2 or more miles, in the aggregate, within any 5 contiguous miles within a 24-month period, to meet the maximum allowable operating pressure (MAOP) requirements in §§ 2711, 2719, or 2720, then the requirements in §§ 1139, 2734, 2736, as applicable, apply to the new class location, and the operator must install valves, including rupture-mitigation valves (RMV) or alternative equivalent technologies, as necessary, to comply with those sections. Such valves must be installed within 24 months of the class location change in accordance with the timing requirement in § 2711.D for compliance after a class location change. [49 CFR 192.610(a)]

B. If a class location change occurs 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. Comply with the valve spacing requirements of § 192.179(a) for the replaced pipeline segment; or [49 CFR 192.610(b)(1)]

2. Install or use existing RMVs or alternative equivalent technologies so that the entirety of the replaced pipeline segments are between at least two RMVs or alternative equivalent technologies. The distance between RMVs and alternative equivalent technologies for the replaced segment must not exceed 20 miles. The RMVs and alternative equivalent technologies must comply with the applicable requirements of § 2736. [49 CFR 192.610(B)(2)]

C. The provisions of Subsection B of this Section do not apply to pipeline replacements that amount to less than 1,000 feet within any 1 contiguous mile during any 24-month period. [49 CFR 192.610(c)]

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

HISTORICALNOTE: Promulgated by the Department of Natural Resources, Office of Conservation,

§2715. Emergency Plans [49 CFR 192.615]

A. – A.1 …

2. establishing and maintaining adequate means of communication with appropriate public safety answering point (i.e., 9-1-1 emergency call center), where direct access to a 9-1-1 emergency call center is available from the location of the pipeline, and fire, police, and other public officials. Operators may establish liaison with the appropriate local emergency coordinating agencies, such as 9-1-1 emergency call centers or county emergency managers, in lieu of communicating individually with each fire, police, or other public entity. An operator must determine the responsibilities, resources, jurisdictional area(s), and emergency contact telephone number(s) for both

local and out-of-area calls of each Federal, State, and local government organization that may respond to a pipeline emergency, and inform such officials about the operator's ability to respond to a pipeline emergency and the means of communication during emergencies. [49 CFR 192.615(a)(2)]

A.3. – A.5. …

6. Taking necessary actions, including but not limited to, emergency shutdown, valve shut-off, or pressure reduction, in any section of the operator's pipeline system, to minimize hazards of released gas to life, property, or the environment. [49 CFR 192.615(a)(6)]

A.7. …

8. notifying the appropriate public safety answering point (*i.e.*, 9-1-1 emergency call center) where direct access to a 9-1-1 emergency call center is available from the location of the pipeline, and fire, police, and other public officials, of gas pipeline emergencies~~ and coordinating with them~~ to coordinate and share information to determine the location of the emergency, including both planned responses and actual responses during an emergency. The operator must immediately and directly notify the appropriate public safety answering point or other coordinating agency for the communities and jurisdictions in which the pipeline is located after receiving a notification of potential rupture, as defined in § 503, to coordinate and share information to determine the location of any release, regardless of whether the segment is subject to the requirements of §§ 1139, 2734, or 2736. [49 CFR 192.615(a)(8)]

A.9. – A.10. …

11. actions required to be taken by a controller during an emergency in accordance with the operator's emergency plans and requirements set forth in §§ 2731, 2734, and 2736. [49 CFR 192.615(a)(11)]

12. Each operator must develop written rupture identification procedures to evaluate and identify whether a notification of potential rupture, as defined in § 503, is an actual rupture event or a non-rupture event. These procedures must, at a minimum, specify the sources of information, operational factors, and other criteria that operator personnel use to evaluate a notification of potential rupture and identify an actual rupture. For operators installing valves in accordance with § 1139.E, § 1139.F, or that are subject to the requirements in § 2734, those procedures must provide for rupture identification as soon as practicable. [49 CFR 192.615(a)(12)]

B. – B.3. …

C. Each operator must establish and maintain liaison with the appropriate public safety answering point (*i.e.*, 9-1-1 emergency call center) where direct access to a 9-1-1 emergency call center is available from the location of the pipeline, as well as fire, police, and other public officials, to: [49 CFR 192.615(c)]

C.1. – 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 9:241 (April 1983), amended LR 10:534 (July 1984), LR 21:822 (August 1995), LR 30:1263 (June 2004), LR 38:117 (January 2012).

§2717. Investigation of Failures [49 CFR 192.617]

A. ~~Each operator shall establish procedures for analyzing accidents and failures, including the selection of samples of the failed facility or equipment for laboratory examination, where appropriate, for the purpose of determining the causes of the failure and minimizing the possibility of a recurrence.~~ Post-failure and incident procedures. Each operator must establish and follow procedures for investigating and analyzing failures and incidents as defined in § 303, including sending the failed pipe, component, or equipment for laboratory testing or examination, where appropriate, for the purpose of determining the causes and contributing factor(s) of the failure or incident and minimizing the possibility of a recurrence. [49 CFR 192.617(a)]

B. Post-failure and incident lessons learned. Each operator must develop, implement, and incorporate lessons learned from a post-failure or incident review into its written procedures, including personnel training and qualification programs, and design, construction, testing, maintenance, operations, and emergency procedure manuals and specifications. [49 CFR 192.617(b)]

C. Analysis of rupture and valve shut-offs. If an incident on an onshore gas transmission pipeline or a Type A gathering pipeline involves the closure of a rupture-mitigation valve (RMV), as defined in § 503, or the closure of alternative equivalent technology, the operator of the pipeline must also conduct a post-incident analysis of all of the factors that may have impacted the release volume and the consequences of the incident and identify and implement operations and maintenance measures to prevent or minimize the consequences of a future incident. The requirements of this Subsection B are not applicable to distribution pipelines or Types B and C gas gathering pipelines. The analysis must include all relevant factors impacting the release volume and consequences, including, but not limited to, the following: [49 CFR 192.617(c)]

1. Detection, identification, operational response, system shut-off, and emergency response communications, based on the type and volume of the incident; [49 CFR 192.617(c)(1)]

2. Appropriateness and effectiveness of procedures and pipeline systems, including supervisory control and data acquisition (SCADA), communications, valve shut-off, and operator personnel; [49 CFR 192.617(c)(2)]

3. Actual response time from identifying a rupture following a notification of potential rupture, as defined at § 503, to initiation of mitigative actions and isolation of the pipeline segment, and the appropriateness and effectiveness of the mitigative actions taken; [49 CFR 192.617(c)(3)]

4. Location and timeliness of actuation of RMVs or alternative equivalent technologies; and [49 CFR 192.617(c)(4)]

5. All other factors the operator deems appropriate. [49 CFR 192.617(c)(5)]

D. Rupture post-failure and incident summary. If a failure or incident on an onshore gas transmission pipeline or a Type A gathering pipeline involves the identification of a rupture following a notification of potential rupture, or the closure of an RMV (as those terms are defined in § 503), or the closure of an alternative equivalent technology, the operator of the pipeline must complete a summary of the post-failure or incident review required by Subsection C of this section within 90 days of the incident, and while the investigation is pending, conduct quarterly status reviews until the investigation is complete and a final post-incident summary is prepared. The final post-failure or incident summary, and all other reviews and analyses produced under the requirements of this section, must be reviewed, dated, and signed by the operator's appropriate senior executive officer. The final post-failure or incident summary, all investigation and analysis documents used to prepare it, and records of lessons learned must be kept for the useful life of the pipeline. The requirements of this Subsection D are not applicable to distribution pipelines or Types B and C gas gathering pipelines. [49 CFR 192.617(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 9:242 (April 1983), amended LR 10:534 (July 1984), LR 30:1264 (June 2004).

§2719. What is the Maximum Allowable Operating Pressure for Steel or Plastic Pipelines? [49 CFR 192.619]

A. – A.2.b. …

3. the highest actual operating pressure to which the segment was subjected during the five years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in Paragraph A.2 of this Section after the applicable date in the third column or the segment was uprated according to the requirements in Chapter 25 of this Subpart. [49 CFR 192.619(a)(3)]

Pipeline Segment	Pressure Date	Test Date
—Onshore gathering line that first became subject to this Subpart (other than §2712) after April 13, 2006.	March 15, 2006, or date line becomes subject to this Subpart, whichever is later.	5 years preceding applicable date in second column.
Onshore regulated gathering pipeline (Type C under § 509.D that first became subject to this part (other than § 2712) on or after May 16, 2022	May 16, 2023, or date pipeline becomes subject to this Subpart, whichever is later	5 years preceding applicable date in second column.
—Onshore transmission line that was a gathering line not subject to this Subpart before March 15, 2006.	March 15, 2006, or date line becomes subject to this Subpart, whichever is later.	5 years preceding applicable date in second column
Offshore gathering lines.	July 1, 1976	July 1, 1971
All other pipelines.	July 1, 1970	July 1, 1965

A.4. – B. …

C. The requirements on pressure restrictions in this Section do not apply in the following instance: ~~. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in Paragraph A.3 of this Section. An operator must still comply with §2711~~ [49 CFR 192.619(c)]

1. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in Paragraph A.3 of this Section. An operator must still comply with §2711. [49 CFR 192.619(c)(1)]

2. For any Type C gas gathering pipeline under §509 existing on or before May 16, 2022, that was not previously subject to this part and the operator cannot determine the actual operating pressure of the pipeline for the 5 years preceding May 16, 2023, the operator may establish MAOP using other criteria based on a combination of operating conditions, other tests, and design with approval from PHMSA. The operator must notify PHMSA in accordance with §518. The notification must include the following information: [49 CFR 192.19(c)(2)]

a. The proposed MAOP of the pipeline; [49 CFR 192.619(c)(2)(i)]

b. Description of pipeline segment for which alternate methods are used to establish MAOP, including diameter, wall thickness, pipe grade, seam type, location, endpoints, other pertinent material properties, and age; [49 CFR 192.619(c)(2)(ii)]

c. Pipeline operating data, including operating history and maintenance history; [49 CFR 192.619(c)(2)(iii)]

d. Description of methods being used to establish MAOP; [49 CFR 192.619(c)(2)(iv)]

e. Technical justification for use of the methods chosen to establish MAOP; and [49 CFR 192.619(c)(2)(v)]

f. Evidence of review and acceptance of the justification by a qualified technical subject matter expert. [49 CFR 192.619(c)(2)(vi)]

D. – F. …

1. operators of pipelines in operation as of [July 1, 2020 must retain any existing records establishing MAOP for the life of the pipeline; [49 CFR 192.6~~07~~19(f)(1)]

2. operators of pipelines in operation as of July 1, 2020 that do not have records establishing MAOP and are required to reconfirm MAOP in accordance with §2724, must retain the records reconfirming MAOP for the life of the pipeline; and [49 CFR 192. 6~~07~~19(f)(2)]

3. operators of pipelines placed in operation after July 1, 2020 must make and retain records establishing MAOP for the life of the pipeline. [49 CFR 192. 6~~07~~19(f)(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 9:242 (April 1983), amended LR 10:534 (July 1984), LR 24:1312 (July 1998), LR 27:1547 (September 2001), LR 30:1264 (June 2004), LR 33:481 (March 2007), LR 35:2807 (December 2009), LR 46:1590 (November 2020), LR 47:1145 (August 2021).

§2734. Transmission lines: Onshore valve shut-off for rupture mitigation. [49 CFR 192.634]

A. For new or entirely replaced onshore transmission pipeline segments with diameters of 6 inches or greater that are located in high-consequence areas (HCA) or Class 3 or Class 4 locations and that are installed after April 10, 2023, an operator must install or use existing rupture-mitigation valves (RMV), or an alternative equivalent technology, according to the requirements of this Section and §§ 1139 and 2736. RMVs and alternative equivalent technologies must be operational within 14 days of placing the new or replaced pipeline segment into service. An operator may request an extension of this 14-day operation requirement if it can demonstrate to PHMSA, in accordance with the notification procedures in § 518, that application of that requirement would be economically, technically, or operationally infeasible. The requirements of this section apply to all applicable pipe replacement projects, even those that do not otherwise involve the addition or replacement of a valve. This section does not apply to pipe segments in Class 1 or Class 2 locations that have a potential impact radius (PIR), as defined in § 3303, that is less than or equal to 150 feet. 49 CFR 192.634(a)]

B. *Maximum spacing between valves*. RMVs, or alternative equivalent technology, must be installed in accordance with the following requirements: 49 CFR 192.634(b)]

1. Shut-off Segment. For purposes of this section, a "shut-off segment" means the segment of pipe located between the upstream valve closest to the upstream endpoint of the new or replaced Class 3 or Class 4 or HCA pipeline segment and the downstream valve closest to the downstream endpoint of the new or replaced Class 3 or Class 4 or HCA pipeline segment so that the entirety of the segment that is within the HCA or the Class 3 or Class 4 location is between at least two RMVs or alternative equivalent technologies. If any crossover or lateral pipe for gas receipts or deliveries connects to the shut-off segment between the upstream and downstream valves, the shut-off segment also must extend to a valve on the crossover connection(s) or lateral(s), such that, when all valves are closed, there is no flow path for gas to be transported to the rupture site (except for residual gas already in the shut-off segment). Multiple Class 3 or Class 4 locations or HCA segments may be contained within a single shut-off segment. The operator is not required to select the closest valve to the shut-off segment as the RMV, as that term is defined in § 503, or the alternative equivalent technology. An operator may use a manual compressor station valve at a continuously manned station as an alternative equivalent technology, but it must be able to be closed within 30 minutes following rupture identification, as that term is defined at § 503. Such a valve used as an alternative equivalent technology would not require a notification to PHMSA in accordance with § 518. [49 CFR 192.634(b)(1)]

2. Shut-off segment valve spacing. A pipeline subject to Subsection A of this Section must have RMVs or alternative equivalent technology on the upstream and downstream side of the pipeline segment. The distance between RMVs or alternative equivalent technologies must not exceed: [49 CFR 192.634(b)(2)]

a. Eight (8) miles for any Class 4 location, [49 CFR 192.634(b)(2)(i)]

b. Fifteen (15) miles for any Class 3 location, or [49 CFR 192.634(b)(2)(ii)]

c. Twenty (20) miles for all other locations, [49 CFR 192.634(b)(2)(iii)]

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 paragraph 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)]

4. *Crossovers.* An operator may use a manual valve as an alternative equivalent technology in lieu of an RMV for a crossover connection if, during normal operations, the valve is closed to prevent the flow of gas by the use of a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator. The operator must develop and implement operating procedures and document that the valve has been closed and locked in accordance with the operator's lock-out and tag-out procedures to prevent the flow of gas. An operator using such a manual valve as an alternative equivalent technology must notify PHMSA in accordance with §§ 518 and 1139. [49 CFR 192.634(b)(4)]

C. Manual operation upon identification of a rupture. Operators using a manual valve as an alternative equivalent technology as authorized pursuant to §§ 518 and 1139 must develop and implement operating procedures that appropriately designate and locate nearby personnel to ensure valve shut-off in accordance with this section and § 2736. 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 § 2736.B. 49 CFR 192.634(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,

§2735. Notification of potential rupture. [49 CFR 192.635]

A. As used in this part, a "notification of potential rupture" refers to the notification of, 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 gas from a pipeline: [49 CFR 192.635(a)]

1. An unanticipated or unexplained pressure loss outside of the pipeline's normal operating pressures, as defined in the operator's written procedures. The operator must establish in its written procedures that an unanticipated or unplanned pressure loss is outside of the pipeline's normal operating pressures when there is a pressure loss greater than 10 percent occurring within a time interval of 15 minutes or less, unless the operator has documented in its written procedures the operational need for a greater pressure-change threshold due to pipeline flow dynamics (including changes in operating pressure, flow rate, or volume), that are caused by fluctuations in gas demand, gas receipts, or gas deliveries; or [49 CFR 192.635(a)(1)]

2. An unanticipated or unexplained flow rate change, pressure change, equipment function, or other pipeline instrumentation indication at the upstream or downstream station that may be representative of an event meeting paragraph (a)(1) of this section; or [49 CFR 192.635(a)(2)]

3. Any unanticipated or unexplained rapid release of a large volume of gas, a fire, or an explosion in the immediate vicinity of the pipeline. [49 CFR 192.635(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 192.635(b)]

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

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

§2736. Transmission lines: Response to a rupture; capabilities of rupture-mitigation valves (RMVs) or alternative equivalent technologies. [49 CFR 192.636]

A. Scope. The requirements in this section apply to rupture-mitigation valves (RMVs), as defined in § 503, or alternative equivalent technologies, installed pursuant to §§ 1139.E, F, G, and 2734. [49 CFR 192.636(a)]

B. Rupture identification and valve shut-off time. An operator must, as soon as practicable but within 30 minutes of rupture identification (*see* § 2715.A.12, fully close any RMVs or alternative equivalent technologies necessary to minimize the volume of gas released from a pipeline and mitigate the consequences of a rupture. [49 CFR 192.636(b)]

C. Open Valves. An operator may leave an RMV or alternative equivalent technology open for more than 30 minutes, as required by Subsection B of this Section, if the operator has previously established in its operating procedures and demonstrated within a notice submitted under § 518 for PHMSA review, that closing the RMV or alternative equivalent technology would be detrimental to public safety. The request must have been coordinated with appropriate local emergency responders, and the operator and emergency responders must determine that it is safe to leave the valve open. Operators must have written procedures for determining whether to leave an RMV or alternative equivalent technology open, including plans to communicate with local emergency responders and minimize environmental impacts, which must be submitted as part of its notification to PHMSA. [49 CFR 192.636(c)]

D. Valve monitoring and operation capabilities. An RMV, as defined in § 503, or alternative equivalent technology, must be capable of being monitored or controlled either remotely or by on-site personnel as follows: [49 CFR 192.636(d)]

1. Operated during normal, abnormal, and emergency operating conditions; [49 CFR 192.636(d)(1)]

2. Monitored for valve status (i.e., open, closed, or partial closed/open), upstream pressure, and downstream pressure. For automatic shut-off valves (ASV), an operator does not need to monitor remotely a valve's status if the operator has the capability to monitor pressures or gas flow rate within each pipeline segment located between RMVs or alternative equivalent technologies to identify and locate a rupture. Pipeline segments that use manual valves or other alternative equivalent technologies must have the capability to monitor pressures or gas flow rates on the pipeline to identify and locate a rupture; and [49 CFR 192.636(d)(2)]

3. Have a back-up power source to maintain SCADA systems or other remote communications for remote-control valve (RCV) or automatic shut-off valve (ASV) operational status, or be monitored and controlled by on-site personnel. [49 CFR 192.636(d)(3)]

E. Monitoring of valve shut-off response status. The position and operational status of an RMV must be appropriately monitored through electronic communication with remote instrumentation or other equivalent means. An operator does not need to monitor remotely an ASV's status if the operator has the capability to monitor pressures or gas flow rate on the pipeline to identify and locate a rupture. [49 CFR 192.636(e)]

F. *Flow modeling for automatic shut-off valves.* Prior to using an ASV as an RMV, an operator must conduct flow modeling for the shut-off segment and any laterals that feed the shut-off segment, so that the valve will close within 30 minutes or less following rupture identification, consistent with the operator's procedures, and in accordance with § 503 and this section. The flow modeling must include the anticipated maximum, normal, or any other flow volumes, pressures, or other operating conditions that may be encountered during the year, not exceeding a period of 15 months, and it must be modeled for the flow between the RMVs or alternative equivalent technologies, and any looped pipelines or gas receipt tie-ins. If operating conditions change that could affect the ASV set pressures and the 30-minute valve closure time after notification of potential rupture, as defined at § 503, an operator must conduct a new flow model and reset the ASV set pressures prior to the next review for ASV set pressures in accordance with § 2945. The flow model must include a time/pressure chart for the segment containing the ASV if a rupture occurs. An operator must conduct this flow modeling prior to making flow condition changes in a manner that could render the 30-minute valve closure time unachievable. [49 CFR 192.636(f)]

G. Manual Valves in non-HCA, Class 1 locations. For pipeline segments in a Class 1 location that do not meet the definition of a high consequence area (HCA), an operator submitting a notification pursuant to §§ 518 and 1139 for use of manual valves as an alternative equivalent technology may also request an exemption from the requirements of § 2736.B. [49 CFR 192.636(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,

§2945. Valve Maintenance: Transmission Lines [49 CFR 192.745]

A. – B. …

C. For each remote-control valve (RCV) installed in accordance with §§ 1139 or 2734, an operator must conduct a point-to-point verification between SCADA system displays and the installed valves, sensors, and communications equipment, in accordance with § 2731.C and E. [49 CFR 192.745(c)]

D. For each alternative equivalent technology installed on an onshore pipeline under §§ 1139.E, 1139.F, or 2734 that is manually or locally operated (i.e., not a rupture-mitigation valve (RMV), as that term is defined in § 503): [49 CFR 192.745(d)]

1. Operators must achieve a valve closure time of 30 minutes or less, pursuant to § 2736.B, through an initial drill and through periodic validation as required in Paragraph D.2 of this Section. An operator must review and document the results of each phase of the drill response to validate the total response time, including confirming the rupture, and valve shut-off time as being less than or equal to 30 minutes after rupture identification. [49 CFR 192.745(d)(1)]

2. Operators must achieve a valve closure time of 30 minutes or less, pursuant to § 2736.B, through an initial drill and through periodic validation as required in Paragraph D.2 of this Section. An operator must review and document the results of each phase of the drill response to validate the total response time, including confirming the rupture, and valve shut-off time as being less than or equal to 30 minutes after rupture identification. [49 CFR 192.745(d)(2)]

3. If the 30-minute-maximum response time cannot be achieved during the drill, the operator must revise response efforts to achieve compliance with § 2736 as soon as practicable but no later than 12 months after the drill. Alternative valve shut-off measures must be in place in accordance with Subsection E of this Section within 7 days of a failed drill. [49 CFR 192.745(d)(3)]

4. Based on the results of response-time drills, the operator must include lessons learned in: [49 CFR 192.745(d)(4)]

a. Training and qualifications programs; [49 CFR 192.745(d)(4)(i)]

b. Design, construction, testing, maintenance, operating, and emergency procedures manuals; and [49 CFR 192.745(d)(4)(ii)]

c. Any other areas identified by the operator as needing improvement. [49 CFR 192.745(d)(4)(iii)]

5. The requirements of this Subsection D do not apply to manual valves who, pursuant to § 2736.G, have been exempted from the requirements of § 2736.B. [49 CFR 192.745(d)(5)]

E. Each operator must develop and implement remedial measures to correct any valve installed on an onshore pipeline under §§ 1139.E, 1139.F, or 2734 that is indicated to be inoperable or unable to maintain effective shut-off as follows: [49 CFR 192.745(e)]

1. Repair or replace the valve as soon as practicable but no later than 12 months after finding that the valve is inoperable or unable to maintain effective shut-off. An operator must request an extension from PHMSA in accordance with § 518 if repair or replacement of a valve within 12 months would be economically, technically, or operationally infeasible; and [49 CFR 192.745(e)(1)]

2. Designate an alternative valve acting as an RMV within 7 calendar days of the finding while repairs are being made and document an interim response plan to maintain safety. Such valves are not required to comply with the valve spacing requirements of this part. [49 CFR 192.745(e)(2)]

F. An operator using an ASV as an RMV, in accordance with §§ 503, 1139, 2734, and 2736, must document and confirm the ASV shut-in pressures, in accordance with 2736.F, on a calendar year basis not to exceed 15 months. ASV shut-in set pressures must be proven and reset individually at each ASV, as required, on a calendar year basis not to exceed 15 months. [49 CFR 192.745(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, LR 9:246 (April 1983), amended LR 10:539 (July 1984), LR 30:1271 (June 2004).

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

A. – B.2. …

C. *Risk analysis for gas releases and protection against ruptures.* If an operator determines, based on a risk analysis, that a rupture-mitigation valve (RMV) or alternative equivalent technology would be an efficient means of adding protection to a high-consequence area (HCA) in the event of a gas release, an operator must install the RMV or alternative equivalent technology. In making that determination, an operator must, at least, evaluate the following factors – timing of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel. An RMV or alternative equivalent technology installed under this paragraph must meet all of the other applicable requirements in this Part. ~~Automatic Shut-Off Valves (ASV) or Remote Control Valves (RCV). If an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors: swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline~~

~~profile, the potential for ignition, and location of nearest response personnel.~~ [49 CFR 192.935(c)]

D. – E. …

F. Periodic evaluations. Risk analyses and assessments conducted under Subsection C of this Section must be reviewed by the operator and certified by a senior executive of the company, for operational matters that could affect rupture-mitigation processes and procedures. Review and certification must occur once per calendar year, with the period between reviews not to exceed 15 months, and must also occur within 3 months of an incident or safety-related condition, as those terms are defined at §§ 303 and 323, respectively. [49 CFR 192.935(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, 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).

Chapter 35. Gas Distribution Pipeline Integrity Management (IM) [49 CFR Part 192 Subpart P]

§3515. What must a Small LPG Operator do to Implement this Chapter? [49 CFR 192.1015]

A. - B.1. ...

2. Identify Threats. The operator must consider, at minimum, the following categories of threats (existing and potential): corrosion(including atmospheric corrosion), natural forces, excavation damage, other outside force damage, material or weld failure, equipment failure, and incorrect operation. [49 CFR 192.1015(b)(2)]

B.3 – 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, LR 38:124 (January 2012), LR. 47:1147 (August 2021).

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]

§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, means where 2 or more miles of pipe, in the aggregate, have been replaced within any 5 contiguous miles within any 24-month period.

***

Notification of Potential Rupture means 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.

***

Rupture-mitigation valve (RMV) means 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.

***

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).

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

A. – A.2.a. …

b. For steel pipelines constructed, replaced, relocated, or otherwise changed after July 3, 2009:~~,~~ ~~design, install, construct, initially inspect, and initially test the pipeline in compliance with this Subpart, unless the pipeline is converted under §30111.~~ [49 CFR 195.11(b)(2)]

i. Design, install, construct, initially inspect, and initially test the pipeline in compliance with this part, unless the pipeline is converted under § 30111. [49 CFR 195.11(b)(2)(i)]

ii. Except for pipelines subject to § 30260.E, such pipelines are not subject to the rupture-mitigation valve (RMV) and alternative equivalent technology requirements in §§ 30258.C and D, 30418, and 30419. [49 CFR 195.11(b)(2)(ii)]

A.2.c. …

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).

§30123. How to notify PHMSA. [49 CFR 195.18]

A. An operator must provide any notification required by this part by: [49 CFR 195.18(a)]

1. Sending the notification by electronic mail to InformationResourcesManager@dot.gov; or [49 CFR 195.18(a)(1)]

2. Sending the notification by mail to ATTN: Information Resources Manager, DOT/PHMSA/OPS, East Building, 2nd Floor, E22-321, 1200 New Jersey Ave. SE., Washington, DC 20590. [49 CFR 195.18(a)(2)]

B. An operator must also notify the appropriate State or local pipeline safety authority when an applicable pipeline segment is located in a State where OPS has an interstate agent agreement, or an intrastate pipeline segment is regulated by that State. [49 CFR 195.18(b)]

C. Unless otherwise specified, if an operator submits, pursuant to §§ 30258, 30260, 30418, 30419, 30420 or 30452 a notification requesting use of a different integrity assessment method, analytical method, sampling approach, compliance timeline, 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 that other method, approach, compliance timeline, or technique. An operator may proceed to use the other method, approach, compliance timeline, or technique 91 days after submittal of the notification unless it receives a letter from the Associate Administrator of Pipeline Safety informing the operator that PHMSA objects to the proposal, or that PHMSA requires additional time and/or information to conduct its review. [49 CFR 195.18(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,

§30258. Valves: General [49 CFR 195.258]

A. – B. …

C. For all onshore hazardous liquid or carbon dioxide 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 and § 30260. An operator using alternative equivalent technology must notify PHMSA in accordance with the procedure in Subsection E of this Section. All RMVs and alternative equivalent technology installed as required by this section must meet the requirements of § 30419. An operator may request an extension of the installation compliance deadline requirements of this paragraph if it can demonstrate to PHMSA, in accordance with the notification procedures in § 30123, that those installation deadline requirements would be economically, technically, or operationally infeasible for a particular new pipeline. [49 CFR 195.258(c)]

D. For all entirely replaced onshore hazardous liquid or carbon dioxide pipeline segments with diameters greater than or equal to 6 inches that have been replaced 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 using alternative equivalent technology must notify PHMSA in accordance with the procedure in paragraph (e) of this section. All valves installed as required by this section must meet the requirements of § 30419. The requirements of this paragraph (d) apply when the applicable pipeline replacement project involves a valve, either through addition, replacement, or removal. An operator may request an extension of the installation compliance deadline requirements of this paragraph if it can demonstrate to PHMSA, in accordance with the notification procedures in § 30123, that those installation deadline requirements would be economically, technically, or operationally infeasible for a particular pipeline replacement project. [49 CFR 195.258(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 § 195.18. 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 compressor 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 § 30123, but it must comply with §§ 30419 and 30420. [49 CFR 195.258(e)]

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).

§30260. Valves: Location [49 CFR 195.260]

A. A valve must be installed at each of the following locations: [49 CFR 195.260]

1. on the suction end and the discharge end of a pump station in a manner that permits isolation of the pump station equipment in the event of an emergency; [49 CFR 195.260(a)]

2. on each ~~line~~ pipeline entering or leaving a breakout storage tank area in a manner that permits isolation of the tank area from other facilities; [49 CFR 195.260(b)]

3. On each pipeline at locations along the pipeline system that will minimize or prevent safety risks, property damage, or environmental harm from accidental hazardous liquid or carbon dioxide discharges, as appropriate for onshore areas, offshore areas, and high-consequence areas (HCA). For newly constructed or entirely replaced onshore hazardous liquid or carbon dioxide pipeline segments, as that term is defined at § 30105, that are installed after April 10, 2023, valve spacing must not exceed 15 miles for pipeline segments that could affect or are in HCAs, as defined in § 30450, and 20 miles for pipeline segments that could not affect HCAs. Valves on pipeline segments that are located in HCAs or which could affect HCAs must be installed at locations as determined by the operator's process for identifying preventive and mitigative measures established pursuant to § 195.452(i) and by using the selection process in Section I.B of Appendix C of Part 195, but with a maximum distance that does not exceed 7½ miles from the endpoints of the HCA segment or the segment that could affect an HCA. An operator may request an exemption from

the compliance deadline requirements of this section for valve installation at the specified valve spacing if it can demonstrate to PHMSA, in accordance with the notification procedures in § 30123, that those compliance deadline requirements would be economically, technically, or operationally infeasible. ~~on each mainline at locations along the pipeline system that will minimize damage or pollution from accidental hazardous liquid discharge, as appropriate for the terrain in open country, for offshore areas, or for populated areas;~~ [49 CFR 195.260(c)]

4. on each lateral takeoff from a ~~trunk line~~ pipeline in a manner that permits shutting off the lateral without interrupting the flow in the trunk line; [49 CFR 195.260(d)]

5. on each side of a water crossing that is more than 100 feet (30 meters) wide from high-water mark to high-water mark ~~unless the Commissioner and Administrator finds in a particular case that valves are not justified;~~ as follows:[49 CFR 195.260(e)]

a. Valves must be installed at locations outside of the 100-year flood plain or be equipped with actuators or other control equipment that is installed so as not to be impacted by flood conditions; and [49 CFR 195.260(e)(1)]

b. The maximum spacing interval between valves that protect multiple adjacent water crossings cannot exceed 1 mile in length. [49 CFR 195.260(e)(1)]

6. on each side of a reservoir holding water for human consumption. [49 CFR 195.260(f)]

7. On each highly volatile liquid (HVL) pipeline that is located in a high-population area or other populated area, as defined in § 30420, and that is constructed, or where 2 or more miles of pipe have been replaced within any 5 contiguous miles within any 24-month period, after April 10, 2023, with a maximum valve spacing of 7 1⁄2 miles. The maximum valve spacing intervals may be increased by 1.25 times the distance up to a 9 3/8-mile spacing, provided the operator: [49 CFR 195.260(g)]

a. Submits for PHMSA review a notification pursuant to § 30123 requesting alternative spacing because installation of a valve at a particular location between a 7-mile to a 7 1⁄2-mile spacing would be economically, technically, or operationally infeasible, and that an alternative spacing would not adversely impact safety; and [49 CFR 195.260(g)(1)]

b. Keeps the records necessary to support that determination for the useful life of the pipeline. [49 CFR 195.260(g)(2)]

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)]

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).

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

A. – C.3. …

4. Determining which pipeline facilities are in areas that would require an immediate response by the operator to prevent hazards to the public, property, or the environment if the facilities failed or malfunctioned, including segments that could affect high-consequence areas (HCA) or are in HCAs, and valves specified in §§ 30418 or 30452.I.4. ~~determining which pipeline facilities are located in areas that would require an immediate response by the operator to prevent hazards to the public if the facilities failed or malfunctioned;~~ [49 CFR 195.402(c)(4)]

5. Investigating and analyzing pipeline accidents and failures, including sending the failed pipe, component, or equipment for laboratory testing or examination where appropriate, to determine the cause(s) and contributing factors of the failure and to minimize the possibility of a recurrence. ~~analyzing pipeline accidents to determine their causes;~~ [49 CFR 195.402(c)(5)]

a. Post-failure and -accident lessons learned. Each operator must develop, implement, and incorporate lessons learned from a post-failure and accident review into its written procedures, including in pertinent operator personnel training and qualifications programs, and in design, construction, testing, maintenance, operations, and emergency procedure manuals and specifications. [49 CFR 195.402(c)(5)(i)]

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 accident analysis of all of 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 incident. The analysis must include all relevant factors impacting the release volume and consequences, including, but not limited to, the following: [49 CFR 195.402(c)(5)(ii)]

i. Detection, identification, operational response, system shut-off, and emergency-response communications, based on the type and volume of the release or failure event; ([49 CFR 195.402(c)(5)(ii)(A)]

ii. Appropriateness and effectiveness of procedures and pipeline systems, including supervisory control and data acquisition (SCADA), communications, valve shut-off, and operator personnel; ([49 CFR 195.402(c)(5)(ii)(B)]

iii. Actual response time from identifying a rupture following a notification of potential rupture, as defined at § 30105, to initiation of mitigative actions and isolation of the segment, and the appropriateness and effectiveness of the mitigative actions taken; ([49 CFR 195.402(c)(5)(ii)(C)]

iv. Location and timeliness of actuation of all RMVs or alternative equivalent technologies; and ([49 CFR 195.402(c)(5)(ii)(D)]

v. All other factors the operator deems appropriate. ([49 CFR 195.402(c)(5)(ii)(E)]

c. Rupture post-failure and accident summary. If a failure or accident on an onshore hazardous liquid or carbon dioxide pipeline involves the identification of a rupture following a notification of potential rupture; the closure of an RMV, as those terms are defined in § 30105; or the closure of an alternative equivalent technology, the operator must complete a summary of the post-failure or -accident review required by subparagraph C.5.b of this section within 90 days of the failure or accident. While the investigation is pending, the operator must conduct quarterly status reviews until the investigation is completed and a final post-failure or -accident review is prepared. The final post-failure or -accident summary and all other reviews and analyses produced under the requirements of this section must be reviewed, dated, and signed by the operator's appropriate senior executive officer. An operator must keep, for the useful life of the pipeline, the final post-failure or -accident summary, all investigation and analysis documents used to prepare it, and records of lessons learned. [49 CFR 195.402(c)(5)(iii)]

C.6. – C.11. …

12. Establishing and maintaining adequate means of communication with the appropriate public safety answering point (i.e., 9-1-1 emergency call center), where direct access to a 9-1-1 emergency call center is available from the location of the pipeline, and fire, police, and other public officials. Operators must determine the responsibilities, resources, jurisdictional area(s), and emergency contact telephone numbers for both local and out-of-area calls of each Federal, State, and local government organization that may respond to a pipeline emergency, and inform the officials about the operator's ability to respond to the pipeline emergency and means of communication during emergencies. Operators may establish liaison with the appropriate local emergency coordinating agencies, such as 9-1-1 emergency call centers or county emergency managers, in lieu of communicating individually with each fire, police, or other public entity. ~~establishing and maintaining liaison with fire, police, and other appropriate public officials to learn the responsibility and resources of each government organization that may respond to a hazardous liquid or carbon dioxide pipeline emergency and acquaint the officials with the operator's ability in responding to a hazardous liquid or carbon dioxide pipeline emergency and means of communication;~~ [49 CFR 195.402(c)(12)]

C.13. – E. …

1. Receiving, identifying, and classifying notices of events that need immediate response by the operator or notice to the appropriate public safety answering point (i.e., 9-1-1 emergency call center), where direct access to a 9-1-1 emergency call center is available from the location of the pipeline, and fire, police, and other appropriate public officials, and communicating this information to appropriate operator personnel for prompt corrective action. Operators may establish liaison with the appropriate local emergency coordinating agencies, such as 9-1-1 emergency call centers or county emergency managers, in lieu of communicating individually with each fire, police, or other public entity. ~~receiving, identifying, and classifying notices of events which need immediate response by the operator or notice to fire, police, or other appropriate public officials and communicating this information to appropriate operator personnel for corrective action;~~ [49 CFR 195.402(e)(1)]

E.2. – E.3. …

4. Taking necessary actions, including but not limited to, emergency shutdown, valve shut-off, or pressure reduction, in any section of the operator's pipeline system, to minimize hazards of released hazardous liquid or carbon dioxide to life, property, or the environment. Each operator must also develop written rupture identification procedures to evaluate and identify whether a notification of potential rupture, as defined in § 30105, is an actual rupture event or non-rupture event. These procedures must, at a minimum, specify the sources of information, operational factors, and other criteria that operator personnel use to evaluate a notification of potential rupture, as defined at § 30105. For operators installing valves in accordance with § 30258.C, § 30258.D, or that are subject to the requirements in § 30418, those procedures should provide for rupture identification as soon as practicable. ~~taking necessary action, such as emergency shutdown or pressure reduction, to minimize the volume of hazardous liquid or carbon dioxide that is released from any section of a pipeline system in the event of a failure;~~ [49 CFR 195.402(e)(4)]

E.5. – E.6. …

7. Notifying the appropriate public safety answering point (i.e., 9-1-1 emergency call center), where direct access to a 9-1-1 emergency call center is available from the location of the pipeline, and fire, police, and other public officials, of hazardous liquid or carbon dioxide pipeline emergencies to coordinate and share information to determine the location of the release, including both planned responses and actual responses during an emergency, and any additional precautions necessary for an emergency involving a pipeline transporting a highly volatile liquid (HVL). The operator must immediately and directly notify the appropriate public safety answering point or other coordinating agency for the communities and jurisdiction(s) in which the pipeline is located after notification of potential rupture, as defined at § 30105, has occurred to coordinate and share information to determine the location of the release, regardless of whether the segment is subject to the requirements of §§ 30258.C or D, 30418, or 30419. ~~notifying fire, police, and other appropriate public officials of hazardous liquid or carbon dioxide pipeline emergencies and coordinating with them preplanned and actual responses during an emergency, including additional precautions necessary for an emergency involving a pipeline system transporting a highly volatile liquid;~~ [49 CFR 195.402(e)(7)]

E.8. – E.9. …

10. Actions required to be taken by a controller during an emergency, in accordance with the operator's emergency plans and §§ 30418 and 30446. ~~§30446~~. [49 CFR 195.402(e)(10)]

F. …

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).

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

A. As used in this part, a notification of potential rupture means refers to 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 from a pipeline: [49 CFR 195.417(a)]

1. An unanticipated or unexplained pressure loss outside of the pipeline's normal operating pressures, as defined in the operator's written procedures. The operator must establish in its written procedures that an unanticipated or unplanned pressure loss is outside of the pipeline's normal operating pressures when there is a pressure loss greater than 10 percent occurring within a time interval of 15 minutes or less, unless the operator has documented in its written procedures the operational need for a greater pressure-change threshold due to pipeline flow dynamics (including changes in operating pressure, flow rate, or volume), that are caused by fluctuations in product demand, receipts, or deliveries; [49 CFR 195.417(a)(1)]

2. An unanticipated or unexplained flow rate change, pressure change, equipment function, or other pipeline instrumentation indication at the upstream or downstream station that may be representative of an event meeting Paragraph A.1 of this Section; or [49 CFR 195.417(a)(2)]

3. Any unanticipated or unexplained rapid release of a large volume of hazardous liquid, 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 Paragraph A of this Section. [49 CFR 195.417(b)]

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

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

§30418. Valves: Onshore valve shut-off for rupture mitigation. [49 CFR 195.418]

A. *Applicability.* For newly constructed and entirely replaced onshore hazardous liquid or carbon dioxide pipeline segments, as defined at § 30105, with diameters of 6 inches or greater that could affect high-consequence areas or are located in high consequence areas (HCA), and that have been installed after April 10, 2023 an operator must install or use existing rupture-mitigation valves (RMV), as defined at § 30105, or alternative equivalent technologies according to the requirements of this section and § 30419. RMVs and alternative equivalent technologies must be operational within 14 days of placing the new or replaced pipeline segment in service. An operator may request an extension of this 14-day operation requirement if it can demonstrate to PHMSA, in accordance with the notification procedures in § 30123, that application of that requirement would be economically, technically, or operationally infeasible. The requirements of this section apply to all applicable pipe replacements, even those that do not otherwise directly involve the addition or replacement of a valve. [49 CFR 195.418(a)]

B. Maximum spacing between valves. RMVs and alternative equivalent technology must be installed in accordance with the following requirements: [49 CFR 195.418(b)]

1. *Shut-off Segment.* For purposes of this Section, a "shut-off segment" means the segment of pipeline located between the upstream valve closest to the upstream endpoint of the replaced pipeline segment in the HCA or the pipeline segment that could affect an HCA and the downstream valve closest to the downstream endpoint of the replaced pipeline segment of the HCA or the pipeline segment that could affect an HCA so that the entirety of the segment that could affect the HCA or the segment within the HCA is between at least two RMVs or alternative equivalent technologies. If any crossover or lateral pipe for commodity receipts or deliveries connects to the replaced segment between the upstream and downstream valves, the shut-off segment also extends to a valve on the crossover connection(s) or lateral(s), such that, when all valves are closed, there is no flow path for commodity to be transported to the rupture site (except for residual liquids already in the shut-off segment). Multiple segments that could affect HCAs or are in HCAs may be contained within a single shut-off segment. All entirely replaced onshore hazardous liquid or carbon dioxide pipeline segments, as defined in § 30105, that could affect or are in an HCA must include a minimum of one valve that meets the requirements of this section and section 30419. The operator is not required to select the closest valve to the shut-off segment as the RMV or alternative equivalent technology. An operator may use a manual pump station valve at a continuously manned station as an alternative equivalent technology. Such a manual valve used as an alternative equivalent technology would not require a notification to PHMSA in accordance with § 30123. [49 CFR 195.418(b)(1)]

2. *Shut-off segment valve spacing.* Pipeline segments subject to Subsection A of this Section must be protected on the upstream and downstream side with RMVs or alternative equivalent technologies. The distance between RMVs or alternative equivalent technologies must not exceed: [49 CFR 195.418(b(2)]

a. For pipeline segments carrying non-highly volatile liquids (HVL): 15 miles, with a maximum distance not to exceed 7½ miles from the endpoints of a shut-off segment: or [49 CFR 195.418(b)(2)(i)]

b. For pipeline segments carrying non-highly volatile liquids (HVL): 15 miles, with a maximum distance not to exceed 7½ miles from the endpoints of a shut-off segment: or [49 CFR 195.418(b)(2)(ii)]

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 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 a such a valve as an alternative equivalent technology must submit a request to PHMSA in accordance with § 30123. [49 CFR 195.418(b)(3)]

4. Crossovers. An operator may use a manual valve as an alternative equivalent technology for a crossover connection if, during normal operations, the valve is closed to prevent the flow of hazardous liquid or carbon dioxide with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator. The operator must document that the valve has been closed and locked in accordance with the operator's lock-out and tag-out procedures to prevent the flow of hazardous liquid or carbon dioxide. An operator using a such a valve as an alternative equivalent technology must submit a request to PHMSA in accordance with § 30123. [49 CFR 195.418(b)(4)]

C. Manual operation upon identification of a rupture. Operators using a manual valve as an alternative equivalent technology pursuant to paragraph (a) of this section must develop and implement operating procedures and appropriately designate and locate nearby personnel to ensure valve shut-off in accordance with this section and § 30419. 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 manually shut off all valves, not to exceed the response time in § 30419.B. [49 CFR 195.418(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,

§30419. Valve capabilities. [49 CFR 195.419]

A. Scope. The requirements in this section apply to rupture-mitigation valves (RMV), as defined in § 30105, or alternative equivalent technology, installed pursuant to §§ 30258 and 30418. [49 CFR 195.419(a)]

B. Rupture identification and valve shut-off time. If an operator observes or is notified of a release of hazardous liquid or carbon dioxide that may be representative of an unintentional or uncontrolled release event meeting a notification of potential rupture (see §§ 30105 and 30417), including any unexplained flow rate changes, pressure changes, equipment functions, or other pipeline instrumentation indications observed by the operator, the operator must, as soon as practicable but within 30 minutes of rupture identification (see § 30402.E.4, identify the rupture and fully close any RMVs or alternative equivalent technologies necessary to minimize the volume of hazardous liquid or carbon dioxide released from a pipeline and mitigate the consequences of a rupture. [49 CFR 195.419(b)]

C. Valve shut-off capability. A valve must have the actuation capability necessary to close an RMV or alternative equivalent technology to mitigate the consequences of a rupture in accordance with the requirements of this section. [49 CFR 195.419(c)]

D. Valve monitoring and operational capabilities. An RMV, as defined in § 30105, or alternative equivalent technology, must be capable of being monitored or controlled by either remote or onsite personnel as follows: [49 CFR 195.419(d)]

1. Operated during normal, abnormal, and emergency operating conditions; [49 CFR 195.419(d)(1)]

2. Monitored for valve status (i.e., open, closed, or partial closed/open), upstream pressure, and downstream pressure. For automatic shut-off valves (ASV), an operator does not need to monitor remotely a valve's status if the operator has the capability to monitor pressures or flow rate within each pipeline segment located between RMVs or alternative equivalent technologies to identify and locate a rupture. Pipeline segments that use an alternative equivalent technology must have the capability to monitor pressures and hazardous liquid or carbon dioxide flow rates on the pipeline in order to identify and locate a rupture; and [49 CFR 195.419(d)(2)]

3. Have a back-up power source to maintain supervisory control and data acquisition (SCADA) systems or other remote communications for remote-control valve (RCV) or ASV operational status or be monitored and controlled by on-site personnel. [49 CFR 195.419(d)(3)]

E. Monitoring of valve shut-off response status. The position and operational status of an RMV must be appropriately monitored through electronic communication with remote instrumentation or other equivalent means. An operator does not need to monitor remotely an ASV's status if the operator has the capability to monitor pressures or hazardous liquid or carbon dioxide s flow rate on the pipeline to identify and locate a rupture. [49 CFR 195.419(e)]

F. Flow modeling for automatic shut-off valves. Prior to using an ASV as an RMV, the operator must conduct flow modeling for the shut-off segment and any laterals that feed the shut-off segment, so that the valve will close within 30 minutes or less following rupture identification, consistent with the operator's procedures, and in accordance with § 30105 and this section. The flow modeling must include the anticipated maximum, normal, or any other flow volumes, pressures, or other operating conditions that may be encountered during the year, not to exceed a period of 15 months, and it must be modeled for the flow between the RMVs or alternative equivalent technologies, and any looped pipelines or hazardous liquid or carbon dioxide receipt tie-ins. If operating conditions change that could affect the ASV set pressures and the 30-minute valve closure time following a notification of potential rupture, as defined at § 30105, an operator must conduct a new flow model and reset the ASV set pressures prior to the next review for ASV set pressures in accordance with § 30420. The flow model must include a time/pressure chart for the segment containing the ASV if a rupture event occurs. An operator must conduct this flow modeling prior to making flow condition changes in a manner that could render the 30-minute valve closure time unachievable. [49 CFR 195.419(f)]

G. Pipelines Not Affecting HCAs. For pipeline segments that are not in a high-consequence area (HCA) or that could not affect an HCA, an operator submitting a notification pursuant to §§ 30123 and 30258 for use of manual valves as an alternative equivalent technology may also request an exemption from the valve operation requirements of § 30419.B.[49 CFR 195.419(g)]

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

§30420. Valve Maintenance [49 CFR 195.420]

A. …

B. ~~Each operator shall, at intervals not exceeding seven and one-half months, but at least twice each calendar year, inspect each mainline valve to determine that it is functioning properly.~~ Each operator must, at least twice each calendar year, but at intervals not exceeding 71⁄2 months, inspect each valve to determine that it is functioning properly. Each rupture-mitigation valve (RMV), as defined in § 30105, 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 drill; 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. …

D. For each remote-control valve (RCV) installed in accordance with §§ 30258.C or 30418, an operator must conduct a point-to-point verification between SCADA system displays and the installed valves, sensors, and communications equipment, in accordance with § 195.446(c) and (e). [49 CFR 195.420(d)]

E. For each alternative equivalent technology installed under §§ 30258.C, 30258.D, or 30418.A that is manually or locally operated (i.e., not an RMV, as that term is defined in § 30105: [49 CFR 195.420(e)]

1. Operators must achieve a response time of 30 minutes or less, as required by § 30419.B, through an initial drill and through periodic validation as required by Subsection E.2 of this Section. An operator must review each phase of the drill response and document the results to validate the total response time, including the identification of a rupture, and valve shut-off time as being less than or equal to 30 minutes after rupture identification. [49 CFR 195.420(e)(1)]

2. Within each pipeline system, and within each operating or maintenance field work unit, operators must randomly select an authorized rupture-mitigation alternative equivalent technology for an annual 30-minute-total response time validation drill simulating worst-case conditions for that location to ensure compliance with § 30419. Operators are not required to close the alternative equivalent technology fully during the drill; a minimum 25 percent valve closure is sufficient to demonstrate compliance with the drill requirements unless the operator has operational information that requires an additional closure percentage for maintaining reliability. The response drill must occur at least once each calendar year, at intervals not to exceed 15 months. Operators must include in their written procedures the method they use to randomly select which alternative equivalent technology is tested in accordance with this paragraph. [49 CFR 195.420(e)(2)]

3. If the 30-minute-maximum response time cannot be achieved in the drill, the operator must revise response efforts to achieve compliance with § 30419 no later than 12 months after the drill. Alternative valve shut-off measures must be in accordance with Subsection F of this Section within 7 days of the drill. [49 CFR 195.420(e)(3)]

4. Based on the results of the response-time drills, the operator must include lessons learned in: [49 CFR 195.420(e)(4)]

a. Training and qualifications programs; [49 CFR 195.420(e)(4)(i)]

b. Design, construction, testing, maintenance, operating, and emergency procedures manuals; and [49 CFR 195.402(e)(4)(ii)]

c. Any other areas identified by the operator as needing improvement. [49 CFR 195.402(e)(4)(ii)]

F. Each operator must implement remedial measures as follows to correct any valve installed on an onshore pipeline in accordance with § 30258.C, or an RMV or alternative equivalent technology installed in accordance with § 30418, that is indicated to be inoperable or unable to maintain effective shut-off: [49 CFR 195.420(f)]

1. Repair or replace the valve as soon as practicable but no later than 12 months after finding that the valve is inoperable or unable to maintain shut-off. An operator may request an extension of the compliance deadline requirements of this section if it can demonstrate to PHMSA, in accordance with the notification procedures in § 30123, that repairing or replacing a valve within 12 months would be economically, technically, or operationally infeasible; and [49 CFR 195.420(f)(1)]

2. Designate an alternative compliant valve within 7 calendar days of the finding while repairs are being made and document an interim response plan to maintain safety. Alternative compliant valves are not required to comply with valve spacing requirements of this part. [49 CFR 195.420(f)(2)]

G. An operator using an ASV as an RMV, in accordance with §§ 30105, 30260, 30418, and 30419, must document, in accordance with § 30419.F, and confirm the ASV shut-in pressures on a calendar year basis not to exceed 15 months. ASV shut-in set pressures must be proven and reset individually at each ASV, as required by § 30419.F, at least each calendar year, but at intervals not to exceed 15 months. [49 CFR 195.420(g)]

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§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 to protect a high consequence area in the event of a hazardous liquid pipeline release, an operator must install the EFRD. In making this determination, an operator must, at least, consider 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 between the pipeline segment and the high consequence area, and benefits expected by reducing the spill size.~~ 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. [49 CFR 195.452(i)(4)]

a. Where EFRDs are installed on pipeline segments in HCAs and that could affect HCAs with diameters of 6 inches or greater and that are placed into service or that have had 2 or more miles of pipe replaced within 5 contiguous miles within a 24-month period after April 10, 2023, the location, installation, actuation, operation, and maintenance of such EFRDs (including valve actuators, personnel response, operational control centers, supervisory control and data acquisition (SCADA), communications, and procedures) must meet the design, operation, testing, maintenance, and rupture-mitigation requirements of §§ 30258, 30260, 30402, 30418, 30419, and 30420. [49 CFR 195.452(i)(4)(i)]

b. The EFRD analysis and assessments specified in Paragraph I.4 of this Section must be completed prior to placing into service all onshore pipelines with diameters of 6 inches or greater and that are constructed or that have had 2 or more miles of pipe within any 5 contiguous miles within any 24-month period replaced after April 10, 2023. Implementation of EFRD findings for RMVs must meet § 301418. [49 CFR 195.452(i)(4)(ii)]

c. An operator may request an exemption from the compliance deadline requirements of this section if it can demonstrate to PHMSA, in accordance with the notification procedures in § 30418, that installing an EFRD by that compliance deadline would be economically, technically, or operationally infeasible. [49 CFR 195.452(i)(4)(ii)]

J. – 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).

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., May 1, 2023, 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 2021-01. All inquiries should be directed to Michael Peikert at the above addresses or by phone to (225) 219-3799. No preamble was prepared.

Richard P. Ieyoub
Commissioner